STATE OF NEW MEXICO
REVISED PROPOSED REGIONAL HAZE STATE IMPLEMENTATION PLAN REVISION
SECOND PLANNING PERIOD (2019-2028)

Prepared by staff of the
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Air Quality Bureau

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List of Abbreviations

2SLB RICE	Two-Stroke Lean Burn Reciprocating Internal Combustion Engine
4SLB RICE	Four-Stroke Lean Burn Reciprocating Internal Combustion Engine
4SRB RICE	Four-Stroke Rich Burn Reciprocating Internal Combustion Engine
40 CFR § 51.308	Title 40 of the Code of Federal Regulations, Part 51, Subpart P, Section 308
40 CFR § 51.309	Title 40 of the Code of Federal Regulations, Part 51, Subpart P, Section 309
AQCB	Albuquerque – Bernalillo County Air Quality Control Board
AQB	New Mexico Environment Department Air Quality Bureau
ATS	Amine Treatment System
BAND1	Bandelier IMPROVE Monitor Site
BART	Best Available Retrofit Technology
b_{ext}	Atmospheric Light Extinction Coefficient
BOAP1	Bosque del Apache IMPROVE Monitor Site
CAA or Act	Clean Air Act
CAVE1	Carlsbad Caverns IMPROVE Monitor Site
CFR	Code of Federal Regulations
CM	Coarse Mass
CT	Combustion Turbine
dv	Deciview(s)
EC	Elemental Carbon
EGU	Electrical Generating Unit
EHD	City of Albuquerque Environmental Health Department
EIB	State of New Mexico Environmental Improvement Board
EPA	U.S. Environmental Protection Agency
Fed. Reg.	Federal Register
FIP	Federal Implementation Plan
FLM	Federal Land Manager
g/bhp-hr	Grams per Brake Horsepower-Hour
GCP	Good Combustion Practices
GCVTC	Grand Canyon Visibility Transport Commission
GICL1	Gila IMPROVE Monitor Site
GUMO1	Guadalupe Mountains IMPROVE Monitor Site
IMPROVE	Interagency Monitoring of Protected Visual Environments
km	Kilometer(s)
LNB	Low NO_X Burner
MID	Most Impaired Days
Mm^{-1}	Inverse Megameters
MMBtu	Million British Thermal Units
MW	Megawatts
NAAQS	National Ambient Air Quality Standard(s)
NH_3	Ammonia
NH_4NO_3	Ammonium Nitrate
$(NH_4)_2SO_4$	Ammonium Sulfate
NMAC	New Mexico Administrative Code
NMED	New Mexico Environment Department
NMSA	New Mexico Statutes Annotated 1978
NO_X	Nitrogen Oxides

NSCR	Non-Selective Catalytic Reduction
NSR	New Source Review
NWR	National Wildlife Refuge
OC	Organic Carbon
$PM_{2.5}$	Particulate Matter 2.5 Microns or Smaller in Diameter
PM_{10}	Particulate Matter 10 Microns or Smaller in Diameter
PNM	Public Service Company of New Mexico
POM	Particulate Organic Matter
ppmvd	Parts per Million by Volume, Dry
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
Q/d	Quantity of Emissions Divided by Distance in kilometers to the Nearest Class I Area
ROA	Revised Ordinances Albuquerque, New Mexico, 1994
RPG	Reasonable Progress Goal
RPO	Regional Planning Organization
SACR1	Salt Creek Wilderness IMPROVE Monitor Site
SAPE1	San Pedro Parks IMPROVE Monitor Site
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SIPr	State Implementation Plan Revision
SJGS	San Juan Generating Station
SMP	Smoke Management Program
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
TPY	Tons per Year
URP	Uniform Rate of Progress
USFS	U.S. Forest Service
USFWS	U.S. Fish and Wildlife Service
USNPS	U.S. National Park Service
VOC	Volatile Organic Compound
WESTAR	Western States Air Resources Council
WHIT1	White Mountain IMPROVE Monitor Site
WHPE1	Wheeler Peak IMPROVE Monitor Site
WRAP	Western Regional Air Partnership
WRAP TSS	Western Regional Air Partnership Technical Support System (Version 2)

Executive Summary

In the 1977 Clean Air Act amendments, Congress declared as a national goal "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from man-made air pollution." The amendments also required the EPA to issue regulations to assure "reasonable progress" toward meeting this national goal. The Regional Haze Rule, promulgated in 1999 and amended in 2017, calls for state and federal agencies to work together to improve visibility in the 156 national parks and wilderness areas designated as federal Class I Areas. New Mexico is home to nine Class I Areas: Bandelier Wilderness Area, Bosque del Apache Wilderness Area, Carlsbad Caverns National Park, Gila Wilderness Area, Pecos Wilderness Area, Salt Creek Wilderness Area, San Pedro Parks Wilderness Area, Wheeler Peak Wilderness Area, and White Mountain Wilderness Area.

Regional haze is visibility impairment from pollutants that absorb and scatter light, reducing overall visibility. These pollutants are emitted by many anthropogenic sources located across a broad geographic area. Under the Regional Haze Rule, states must develop periodic state implementation plan (SIP) revisions that include long-term strategies addressing regional haze visibility impairment for Class I Areas within their borders and Class I Areas in other states that may be affected by emissions from sources within their borders. In establishing their long-term strategies, states must evaluate and determine the emission reduction measures necessary to make reasonable progress toward the goal of no "impairment . . . from man-made air pollution" in Class I Areas by 2064. The rule also requires states to establish goals for each affected Class I Area that provide for improved visibility on the most impaired days and ensure no degradation in visibility on the clearest days.

This document, consisting of 12 chapters, represents the latest comprehensive revision to the State of New Mexico's Regional Haze SIP and covers the second planning period (2019 to 2028). It describes visibility conditions in New Mexico's Class I Areas; the methodology used by NMED to select sources for an analysis of emission control measures; the control measures NMED determined are necessary to make reasonable progress and corresponding emissions limitations and compliance schedules; NMED's "robust demonstration" for Salt Creek Wilderness Area, which is the sole Class I Area in New Mexico currently not on track to achieve natural visibility conditions by 2064; and coordination and consultation with Federal Land Managers, EPA, states, Tribes, and other interested parties. It also includes a periodic progress report describing the status of implementation of the control measures in New Mexico's Regional Haze SIP for the first planning period as required by the Regional Haze Rule. An overview of the structure of this Regional Haze SIP revision and the contents of the individual chapters is provided below.

Chapter 1 provides definitions of important visibility-related terms, a summary of the Regional Haze Rule's history and regulatory requirements, and an overview of the regional haze planning process and the roles of the various entities involved.

Chapter 2 provides a brief introduction to each of New Mexico's nine Class I Areas and to the Interagency Monitoring of Protected Visual Environments (IMPROVE) network monitor sites that provide data on visibility conditions in each area.

Chapter 3 provides detailed IMPROVE monitoring data for New Mexico's Class I Areas. For each Class I Area, changes in visibility conditions on the most impaired and clearest days over time are assessed, as are the contributions to visibility interference of each of the major haze-forming aerosol species.

NMED's analysis of monitoring trends shows that ammonium nitrate (NH_4NO_3) and ammonium sulfate ($(NH_4)_2SO_4$) are important contributors to visibility impairment at all Class I Areas on both the most impaired days and clearest days. It also shows improving visibility at all areas since the baseline period (2000-2004) on both the most impaired days and clearest days. Chapter 3 also provides the Uniform Rate of Progress (URP) for each New Mexico Class I Area. The URP represents the uniform rate of visibility improvement that would need to be maintained during each planning period to attain natural visibility conditions by 2064.

Chapter 4 describes New Mexico's analysis of the potential impact of emissions from sources within New Mexico on visibility in out-of-state Class I Areas. The analysis suggests possible impacts on Class I Areas in Colorado and Texas from sources in the San Juan Basin in the Four Corners region in northwestern New Mexico, and in the Permian Basin in southeastern New Mexico. New Mexico addresses these potential out-of-state impacts in this SIP revision through a robust source selection process and control measures determinations that will provide for significant reductions in nitrogen oxides (NO_X) and sulfur dioxide (SO_2) emissions in these areas, which can be reasonably expected to improve visibility at both in-state and out-of-state Class I Areas.

Chapter 5 contains an embedded progress report describing the status of implementation of the control measures included in New Mexico's Regional Haze SIP for the first planning period during the five years following the required submittal of a mid-period progress report in 2013. All first period measures were fully implemented during this time, resulting in thousands of tons of NO_X and SO_2 emissions reductions. These reductions are responsible, in part, for improving visibility conditions at New Mexico's Class I Areas since the baseline period.

Chapter 6 describes NMED's source selection process for the second planning period. NMED worked closely with the City of Albuquerque Environmental Health Department (EHD) and consulted with Federal Land Managers on the methodology used to select sources for an analysis of emission control measures. Based on recommendations from the Western Regional Air Partnership (WRAP), NMED and EHD collectively used the Q/d method, which involved calculating Q/d scores for all New Mexico Title V facilities (excluding those on Tribal lands) and comparing them to a threshold necessary to capture 80% of the total NO_X and SO_2 emissions from all Title V facilities combined. This resulted in the selection of 24 facilities statewide for analysis, including 23 in NMED's jurisdiction, which encompasses all areas of New Mexico, except Bernalillo County and Tribal lands. NMED then applied a secondary (tier two) screen based on allowable emissions to select 133 individual emissions units at the 23 facilities within its jurisdiction for an analysis of emission control measures for NO_X and/or SO_2, which are precursors to the primary haze-forming aerosol species impacting visibility in New Mexico's Class I Areas.

Chapter 7 describes NMED's analyses of emission control measures for individual emissions units, which took into consideration four statutory factors (costs of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of the source), and its subsequent reasonable progress control measures determinations. Cost effectiveness was the predominant factor in NMED's decision-making, with controls below $10,000/ton cost generally deemed cost effective and necessary for reasonable progress. Based on this threshold and other decision-making criteria, NMED determined that reasonable progress requires new controls on 50 of the emissions units evaluated. Emissions reductions from these controls, coupled with emission reductions due to recent retirements and previously installed controls, are estimated to result in approximately 17,964 tons/yr of NO_X reductions and 5,348 tons/yr of SO_2 reductions during the second planning period.

Chapter 8 provides New Mexico's long-term strategy for the second planning period, which is the core of this SIP revision. The long-term strategy includes all measures NMED determined are necessary to make reasonable progress. These include new emissions limitations and compliance schedules for the 50 emissions units NMED determined require new controls; the permanent retirement of 34 emissions units at facilities that have shut down or made significant operational changes since the start of the second planning period; new emissions limitations to ensure the continued use of in-place controls on eight (8) emissions units; and the incorporation into the SIP of certain NSR permit conditions to ensure the continued use of in-place controls on the amine treatment systems at four (4) facilities. Chapter 8 also examines the anticipated net effect on visibility due to projected changes in emissions during the second planning period. These changes are projected to result in decreased anthropogenic contributions to aerosol light extinction at all New Mexico Class I Areas at the end of the period.

Chapter 9 and Chapter 10 provide reasonable progress goals and URP glidepath checks for New Mexico's nine Class I Areas. Reasonable progress goals reflect the visibility conditions that are projected to be achieved by the end of the second planning period as a result of the long-term strategy and must provide for improvement in visibility on the most impaired days and no degradation in visibility on the clearest days. URP glidepath checks involve comparing reasonable progress goals to the URP glidepath to ensure they provide for a rate of visibility improvement that equals or exceeds the URP. NMED's glidepath checks show that eight of New Mexico's nine Class I Areas are projected to fall below the URP glidepath in 2028, which is indicative of a faster rate of improvement than the URP. Only Salt Creek Wilderness Area in Chaves County is projected to be above the glidepath, indicating a slower rate of improvement than the URP. As such, Chapter 10 also includes a "robust demonstration" for Salt Creek Wilderness Area showing that that all reasonable measures to improve visibility have been included in the long-term strategy, as required by the Regional Haze Rule.

Chapter 11 gives an overview of how NMED has made efforts to keep open paths of communication and coordination with outside entities throughout the process and development of this SIP Revision and to fulfill specific regulatory requirements on consultations with states and FLMs. Monthly meetings with WRAP and EPA, along with weekly check-ins with EHD, helped answer any questions that arose during the source selection and SIPr development processes. NMED's dedicated Regional Haze website at https://www.env.nm.gov/air-quality/reg-haze/ has allowed NMED to engage with members of the public and stakeholders throughout the planning process, along with providing a platform to post relevant updates and background information on the Regional Haze Rule.

Finally, Chapter 12 covers additional requirements pertaining to Regional Haze SIPs, including an assessment of NMED's current monitoring strategy for measuring, characterizing and reporting visibility impairment in New Mexico's Class I Areas, and various emission inventory-related provisions.

In addition to the main SIP narrative provided in Chapters 1-12, this SIP revision includes a number of appendices providing reference materials, technical support, and other documentation. These include WRAP's emission inventory and modeling references (Appendices A and B), NMED's four-factor analyses and control measures determinations technical support document (Appendix C), four-factor analyses supporting documentation (Appendix D), coordination and outreach supporting documentation (Appendix E), federal land manager formal consultation supporting documentation (Appendix F), and proposed rule 20.2.68 NMAC – Regional Haze Requirements (Appendix G).

Chapter 1: Introduction

The New Mexico Environment Department (NMED) Air Quality Bureau (AQB) prepared this Regional Haze State Implementation Plan Revision (SIPr) element in accordance with U.S. Environmental Protection Agency (EPA) regulations for consideration by the New Mexico Environmental Improvement Board (EIB). The plan element describes how New Mexico meets the requirements of the federal regulation known as the Regional Haze Rule, which appears in Title 40 of the Code of Federal Regulations, Part 51, Subpart P, Sections 308 and 309 (40 CFR §§ 51.308 and 309). The purpose of the Regional Haze Rule is to reduce visibility impairment in 156 national parks and wilderness areas across the country due to haze caused by emissions of manmade air pollutants known to result in such impairment. Further details about the Regional Haze Rule appear in this chapter and throughout this Regional Haze SIPr element for New Mexico.

NMED refers to this document as a plan "element" for the state because it functions in tandem with a similar plan element, to be proposed separately by the City of Albuquerque Environmental Health Department (EHD) for consideration by the Albuquerque - Bernalillo County Air Quality Control Board (AQCB) for application to the City of Albuquerque and Bernalillo County, which are a separate air quality jurisdiction from the rest of New Mexico. The two plan elements together will function as a single plan for the entire state of New Mexico, excluding Tribal lands. As discussed below, EPA has requested this cooperative approach because the Regional Haze Rule applies to entire states, not to political subdivisions of states.

This introductory chapter provides an overview of the Regional Haze Rule and its requirements, how this SIPr satisfies those requirements, and the organizations involved in preparing and approving this SIPr at the local, state, regional, and federal level. For simplicity, this New Mexico Regional Haze State Implementation Plan Revision element for the second planning period (2019-2028) for the entire state, excluding the City of Albuquerque/Bernalillo County and Tribal lands, will be referred to as the “Regional Haze SIPr Rd 2 (2019-2028)” throughout the remainder of this document.

1.1 Definitions of Visibility-Related Concepts

Implementation of the Regional Haze Rule depends on sound technical methods to characterize visibility in protected areas, which are known as mandatory Federal Class I areas (Class I Area). A list of selected definitions from 40 CFR § 51.301,[1] which apply to 40 CFR § 51.308 that covers EPA’s Regional Haze Rule requirements, is provided in Section 1.1.1: 40 CFR § 51.301 Definitions. These definitions will help to serve as a reference for some of the technical terms that will be used throughout this Regional Haze SIPr Rd 2 (2019-2028). Other relevant definitions and explanations of visibility-related terms are provided in Section 1.1.2: Other definitions.

1.1.1 40 CFR § 51.301 definitions

- **Baseline visibility condition** means the average of the five annual averages of the individual values of daily visibility for the period 2000–2004 unique to each Class I Area for either the most impaired days or the clearest days.

[1] https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-51/subpart-P/section-51.301.

- **Best Available Retrofit Technology (BART)** means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

- **Clearest days** means the twenty percent of monitored days in a calendar year with the lowest values of the deciview index.

- **Current visibility condition** means the average of the five annual averages of individual values of daily visibility for the most recent period for which data are available unique to each Class I Area for either the most impaired days or the clearest days.

- **Deciview (dv)** is the unit of measurement on the deciview index scale for quantifying in a standard manner human perceptions of visibility.

- **Deciview index** means a value for a day that is derived from calculated or measured light extinction, such that uniform increments of the index correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to very obscured. The deciview index is calculated based on the following equation (for the purposes of calculating deciview using IMPROVE data, the atmospheric light extinction coefficient must be calculated from aerosol measurements and an estimate of Rayleigh scattering):

$$10 \ln (b_{ext}/10\ Mm{-}1)$$

  where, b_{ext} = atmospheric light extinction coefficient, expressed in inverse megameters (Mm−1).

- **Federal Land Manager (FLM)** means the Secretary of the department with authority over the Federal Class I Area (or the Secretary's designee) or, with respect to Roosevelt-Campobello International Park, the Chairman of the Roosevelt-Campobello International Park Commission.

- **Federally enforceable** means all limitations and conditions which are enforceable by the Administrator under the Clean Air Act including those requirements developed pursuant to parts 60 and 61 of [Title 40], requirements within any applicable State Implementation Plan, and any permit requirements established pursuant to § 52.21 of [Chapter I] or under regulations approved pursuant to part 51, 52, or 60 of [Title 40].

- **Fixed capital cost** means the capital needed to provide all of the depreciable components.

- **Fugitive emissions** means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

- **Implementation plan** means, for the purposes of [Part 51], any State Implementation Plan, Federal Implementation Plan, or Tribal Implementation Plan.

- **Native American tribe or tribe** means any Native American tribe, band, nation, or other organized group or community, including any Alaska Native village, which is federally recognized as eligible for the special programs and services provided by the United States to Native Americans because of their status as Native Americans.

- **In existence** means that the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time.

- **Installation** means an identifiable piece of process equipment.

- **Integral vista** means a view perceived from within the mandatory Class I Federal area of a specific landmark or panorama located outside the boundary of the mandatory Class I Federal area.

- **Least impaired days** means the twenty percent of monitored days in a calendar year with the lowest amounts of visibility impairment.

- **Major stationary source** and major modification mean major stationary source and major modification, respectively, as defined in [40 CFR § 51.166].

- **Mandatory Class I Federal Area or Mandatory Federal Class I Area** means any area identified in part 81, subpart D of [Title 40].

- **Most impaired days** means the twenty percent of monitored days in a calendar year with the highest amounts of anthropogenic visibility impairment.

- **Natural conditions** reflect naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration, and may refer to the conditions on a single day or a set of days. These phenomena include, but are not limited to, humidity, fire events, dust storms, volcanic activity, and biogenic emissions from soils and trees. These phenomena may be near or far from a Class I Area and may be outside the United States.

- **Natural visibility** means visibility (contrast, coloration, and texture) on a day or days that would have existed under natural conditions. Natural visibility varies with time and location, is estimated or inferred rather than directly measured, and may have long-term trends due to long-term trends in natural conditions.

- **Natural visibility condition** means the average of individual values of daily natural visibility unique to each Class I Area for either the most impaired days or the clearest days.

- **Potential to emit** means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its

design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

- **Prescribed fire** means any fire intentionally ignited by management actions in accordance with applicable laws, policies, and regulations to meet specific land or resource management objectives.

- **Regional haze** means visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources.

- **Secondary emissions** means emissions which occur as a result of the construction or operation of an existing stationary facility but do not come from the existing stationary facility. Secondary emissions may include, but are not limited to, emissions from ships or trains coming to or from the existing stationary facility.

- **Stationary Source** means any building, structure, facility, or installation which emits or may emit any air pollutant.

- **Visibility** means the degree of perceived clarity when viewing objects at a distance. Visibility includes perceived changes in contrast, coloration, and texture elements in a scene.

- **Visibility impairment or anthropogenic visibility impairment** means any humanly perceptible difference due to air pollution from anthropogenic sources between actual visibility and natural visibility on one or more days. Because natural visibility can only be estimated or inferred, visibility impairment also is estimated or inferred rather than directly measured.

- **Visibility in any mandatory Class I Federal area** includes any integral vista associated with that area.

1.1.2 Other definitions

These additional definitions are from the Western Regional Air Partnership Technical Support System glossary,[2] unless otherwise noted.

- **Aerosol** means suspensions of tiny liquid and/or solid particles in the air.

- **Anthropogenic** means produced by human activities.

- **Class I Area** as defined by the Clean Air Act, include national parks greater than 6,000 acres, wilderness areas and national memorial parks greater than 5,000 acres, and international parks that existed as of August 1977.[3]

- **Extinction Budget** means apportioning the extinction coefficient to atmospheric constituents to analysis estimate the change in visibility caused by a change in constituent concentrations.

[2] https://views.cira.colostate.edu/tssv2/Pub/Glossary.aspx.

[3] Equivalent to Section 1.1.1 - Mandatory Class I Federal Area or Mandatory Federal Class I Area

- **Extinction coefficient** means a measure of the ability of particles or gases to absorb and scatter photons from a beam of light; a number that is proportional to the number of photons removed from the sight path per unit length.

- **Haze** means an atmospheric aerosol of sufficient concentration to be visible. The particles are so small that they cannot be seen individually, but are still effective in scene distortion and visual range restriction.

- **Light Extinction** means the attenuation of light due to scattering and absorption as it passes through a medium.

- **Particulate matter** means particles found in the air, including dust, dirt, soot, smoke, and liquid droplets. Some particles are large or dark enough to be seen as soot or smoke. Others are so small that individually they can only be detected with an electron microscope.[4]

- **$PM_{2.5}$** means particulate matter smaller than 2.5 microns in diameter.[5]

- **PM_{10}** means particulate matter less than 10 microns in diameter.[6]

- **Rayleigh Scattering** means the scattering of light by particles much smaller than the wavelength of the light, e.g., molecular scattering in the natural atmosphere.[7]

- **Secondary aerosols** means aerosols formed by the interaction of two or more gas molecules and/or primary aerosols.

- **URP framework** means the interrelated Regional Haze Rule requirements regarding the quantification of historical and projected visibility conditions using specific metrics, the quantification of natural conditions, the quantification of the uniform rate of progress (URP) that would achieve natural visibility conditions for the 20 percent most anthropogenically impaired days in 2064, the URP glidepath, the setting of reasonable progress goals (RPG) for the end of the implementation period, and the comparison of the RPG for the 20 percent most anthropogenically impaired days to the URP glidepath.[8]

- **URP glidepath** means the hypothetical straight-line path on the deciview scale between the baseline period visibility condition in 2000-2004 (associated with December 31, 2004) and the sum of the natural visibility condition and optional adjustments for international anthropogenic impacts and impacts from certain wildland prescribed fires (associated with December 31, 2064), for the 20 percent most anthropogenically impaired days for a particular Class I Area.[9]

- **Visual Range** means the distance at which a large black object just disappears from view.

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[4] https://www.nps.gov/subjects/air/glossary.htm.
[5] *Id*.
[6] *Id*.
[7] *Id*.
[8] https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.
[9] *Id*.

- **Western Regional Air Partnership (WRAP)** is one of five Regional Planning Organizations. It includes the states and Tribal areas encompassed by Arizona, California, Colorado, Idaho, Montana, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming and is affiliated with the Western States Air Resources Council.

1.2 A Brief History of the Regional Haze Rule

In 1977, Congress adopted amendments to the federal Clean Air Act (CAA or Act) protecting visibility in Class I Areas.[10] This early provision of the CAA focused on emissions from major sources of human-caused (i.e. anthropogenic) air pollutants that "may reasonably be anticipated to cause or contribute" to visibility impairment at Class I Areas located close to the contributing major sources. Over time, EPA and other stakeholders realized that further action was necessary to address more numerous, widely scattered sources that may not be located close to a Class I Area. In light of this need, Congress amended the visibility protection provisions of the CAA in 1990.[11] In accordance with these CAA provisions, as amended, EPA adopted the Regional Haze Rule in 1999.[12] The rule addressed the more numerous, widely scattered sources responsible for Class I Area visibility issues. It required states to take gradual steps over time to improve visibility at Class I Areas, returning visibility to "natural conditions," free of anthropogenic interference, by the year 2064. To that end, the rule required states to submit Regional Haze State Implementation Plans (SIPs) beginning in 2003 and at ten-year intervals thereafter, corresponding with ten-year planning periods. However, litigation substantially delayed the SIP submittal process and required EPA to amend the Regional Haze Rule.[13] The initial Regional Haze SIPs were ultimately due to EPA by December 17, 2007.[14]

On December 1, 2003 (received by EPA December 22, 2003) and June 24, 2011 (received by EPA July 5, 2011), the State of New Mexico submitted Regional Haze SIPs to meet the requirements of 40 CFR § 51.309 (the Section 309 SIP) and 51.309(g) (the Section 309(g) SIP), respectively. The Section 309 SIP addressed the first phase of Regional Haze Rule requirements, with an emphasis on stationary source sulfur dioxide (SO_2) emission reductions and a focus on improving visibility in the 16 Class I Areas on the Colorado Plateau (including San Pedro Parks Wilderness Area in New Mexico). Under 40 CFR § 51.309(g)(2)(i), states that prepare Section 309 SIPs can take credit for improved visibility in Class I Areas not on the Colorado Plateau. The Section 309(g) SIP extended the scope of the Section 309 SIP to all Class I Areas within the state, addressing the visibility requirements and improvements in New Mexico's remaining eight Class I Areas, including Bandelier Wilderness Area, Bosque del Apache Wilderness Area, Carlsbad Caverns National Park, Gila Wilderness Area, Pecos Wilderness Area, Salt Creek Wilderness Area, Wheeler Peak Wilderness Area, and White Mountain Wilderness Area.

On November 27, 2012, EPA published final approval of New Mexico's 2003 and 2011 SIP submittals with the exception of the Best Available Retrofit Technology (BART) determination for nitrogen oxides (NO_X) for San Juan Generating Station (SJGS).[15] EPA had previously issued a federal implementation plan

[10] 42 U.S.C. § 7491.
[11] 42 U.S.C. § 7492.
[12] 64 Fed. Reg. 35714 (July 1, 1999) (Regional Haze Regulations).
[13] 71 Fed. Reg. 60612 (October 13, 2006) (Regional Haze Regulations; Revisions to Provisions Governing Alternative to Source-Specific Best Available Retrofit Technology (BART) Determinations).
[14] 40 CFR § 51.308(b).
[15] 77 Fed. Reg. 70693 (November 27, 2012) (Approval and Promulgation of State Implementation Plans; State of New Mexico; Regional Haze Rule Requirements for Mandatory Class I Areas).

(FIP) containing a different NO_X BART determination for SJGS.[16] New Mexico challenged EPA's NO_X BART FIP for SJGS, and the case was filed in the U.S. Court of Appeals for the Tenth Circuit.[17] To resolve litigation arising from New Mexico's and EPA's incompatible SJGS NO_X BART determinations, New Mexico, EPA, and the Public Service Company of New Mexico (PNM, operator of the SJGS) reached a tentative agreement (contained in a Term Sheet) on February 15, 2013, on an alternative plan to address pollution control requirements for SJGS under the CAA's requirements for regional haze and interstate transport for visibility. The agreement called for a new BART determination based on the retirement of Units 2 and 3 at the facility by December 31, 2017; the installation of Selective Non-Catalytic Reduction technology on the remaining Units 1 and 4, with a NO_X emission rate of no greater than 0.23 lbs/MMBtu; and further reductions in SO_2 emissions. On September 5, 2013, the EIB unanimously approved a SIP revision incorporating the terms of the tentative agreement as a revised BART determination. The revised SIP was submitted to EPA on October 8, 2013, and on December 17, 2013, EPA determined that the revised SIP submission was administratively complete.

On October 9, 2014, EPA approved a revision to the New Mexico Regional Haze SIP that addressed BART for SJGS, making the emission limitations federally enforceable, satisfying CAA 110(a)(2)(D)(i)(II) with respect to interstate transport of air pollution and visibility protection for the 8-hour ozone National Ambient Air Quality Standard (NAAQS) and the $PM_{2.5}$ NAAQS.[18] EPA simultaneously withdrew its FIP for New Mexico that applied to SJGS.[19] Therefore, the requirement for New Mexico under Section 110(a)(2)(D)(i)(II) is satisfied by the SIP revisions approved on November 27, 2012.

Originally, Regional Haze SIPs for the second planning period (2019 to 2028) were to be submitted to EPA in 2018. However, on January 10, 2017, EPA revised the Regional Haze Rule so that the SIPs for the second planning period would instead be due July 31, 2021.[20] However, the years for the second planning period remain 2019 to 2028 despite the revised SIP submittal deadline.

Future Regional Haze SIP submittals are due by July 31, 2028, and at ten-year intervals thereafter, unless EPA revises the Regional Haze Rule again.[21]

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[16] 76 Fed. Reg. 52388 (August 22, 2011) (Approval and Promulgation of Implementation Plans; New Mexico; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determination).

[17] NMED filed a "Petition for Reconsideration and Stay of Final Rule" on or about October 21, 2011. The Navajo Nation joined in the PNM and NMED petitions for reconsideration and for administrative stay. The petitions for reconsideration and administrative requests for stay of the Final Rule are still pending." (Page 22 / Page 28 Bate Stamp, Appellate Case: 11-9552, 1/13/12). On April 27, 2012, New Mexico's Governor Susana Martinez sent a letter to EPA Administrator Lisa Jackson urging EPA to work with PNM and the NMED to find an alternative to the federal and state plans. Both the Governor and PNM asked for a stay of the federal rule to delay the implementation since significant dollars were at stake. On July 16, 2012, EPA issued an administrative 90-day stay. PNM agreed to work with the parties to find an alternative. (Pat Vincent-Collawn and Maureen Gannon, Regional Haze and the San Juan Generating Station, EM Magazine, May 2014, available at http://www.awma.org/EM).

[18] 79 Fed. Reg. 60985 (October 9, 2014) (Approval and Promulgation of Implementation Plans; New Mexico; Regional Haze and Interstate Transport Affecting Visibility State Implementation Plan Revisions).

[19] 79 Fed. Reg. 60978 (October 9, 2014) (Approval and Promulgation of Implementation Plans; New Mexico; Regional Haze and Interstate Transport Affecting Visibility State Implementation Plan Revisions; Withdrawal of Federal Implementation Plan for the San Juan Generating Station).

[20] 82 Fed. Reg. 3078 (January 10, 2017) (Protection of Visibility: Amendments to Requirements for State Plans).

[21] 40 CFR § 51.308(f). On December 23, 2024, EPA proposed revising the due date for the next required regional haze SIP revision from the current due date of July 31, 2028, to a revised due date of July 31, 2031. 89 Fed. Reg.

1.3 Overview of Regulatory Provisions in the Regional Haze Rule

This Section summarizes the major requirements of the Regional Haze Rule.[22] More detailed discussion of specific requirements will be presented in individual chapters of this Regional Haze SIPr Rd 2 (2019-2028), as warranted. The following discussion refers to regional haze requirements for a state. As a practical matter, a separate air quality jurisdiction within a state, such as Albuquerque – Bernalillo County, typically works in conjunction with state agencies to achieve a Regional Haze planning approach that works in an integrated fashion for the entire state.

1.3.1 Clean Air Act distinction between protection of visibility versus protection of health

The Regional Haze Rule, and the Clean Air Act visibility protection provisions upon which it is based, are not health-based air quality standards. They protect visibility in Class I Areas by gradually reducing visibility-impairing anthropogenic air pollutants over time.[23] Such pollutants are also known to have effects on human health, but the federal regulatory scheme addresses health effects by a different mechanism: the National Ambient Air Quality Standards.[24] The NAAQS define the maximum amount of six common air pollutants that can be present in outdoor air without harming public health.[25]

1.3.2 Specific regulatory provisions

The Regional Haze Rule establishes a multi-step process to improve visibility at Class I Areas. The Regional Haze Rule divides the process into ten-year planning periods. During each period, states undertake a series of steps to achieve gradual improvement in visibility, which must be documented in a Regional Haze SIP revision. The current planning period covers the years from 2019 to 2028. However, Regional Haze SIP revisions for this period were not due until July 31, 2021. EPA designed the Regional Haze Rule to achieve the Clean Air Act goal for visibility to be restored to natural conditions for each Class I Area.

The Regional Haze Rule requires a Regional Haze SIP revision that estimates emissions from natural sources (such as sea salt, dust, and wildfire smoke), emissions from anthropogenic sources, and amounts of pollution which are beyond the control of states (such as international emissions and some transportation-related emissions). Before submitting their Regional Haze SIP revisions for a ten-year planning period, states must complete a series of steps, described below. Further details about each step will appear throughout this Regional Haze SIPr Rd 2 (2019-2028).

104471 (December 23, 2024) (Regional Haze Third Implementation Period; Extension of the State Implementation Plan Due Date). At the time of preparation of this Regional Haze SIPr Rd2 (2019-2018), EPA had not taken final action on this proposal.

[22] This subsection is substantially based on an overview of the Regional Haze Rule prepared by the Western Regional Air Partnership. See WRAP, Overview of Regional Haze Planning, Regional Haze Planning Work Group Consensus, May 7, 2019, available at https://westar.org/wp-content/uploads/2022/09/Overview-of-RH-Planning-RHPWG-consensus-May7_2019.pdf.

[23] 42 U.S.C. §§ 7491 and 7492; 40 CFR §§ 51.300 to 51.309.

[24] 42 U.S.C. §§ 7408 and 7409; 40 CFR §§ 50.1 to 50.19.

[25] The six pollutants for which EPA must set National Ambient Air Quality Standards are carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and sulfur dioxide.

1) States review the data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring network, [26] which measures the visibility-impairing pollutant concentrations at Class I Areas throughout the U.S.
2) States calculate the amount of air pollutants known to contribute to poor visibility that is emitted within their boundaries from a variety of different sources.
3) States analyze this data on visibility and pollutants to identify pollution sources likely contributing to visibility problems at particular areas, both inside their own borders and in other states.
4) Each state identifies "reasonable" pollution control methods that will reduce emissions from human-caused sources and thus improve visibility at Class I Areas.
5) Technical experts at Regional Planning Organizations (RPO), which assist states in preparing Regional Haze SIPs, use computer modeling or other technical approaches to understand how pollution control measures at particular anthropogenic pollutant sources can reasonably be expected to improve visibility at each Class I Area over a ten-year Regional Haze planning period.
6) Throughout Regional Haze SIP development, states consult informally with the Federal Land Managers (FLMs) of the Class I Areas within their jurisdiction to communicate the intended benefits of proposed regulatory actions, and then ask the FLMs for a formal review of the plan before a formal public hearing on the plan is held. The Regional Haze Rule requires states to consult with other states that have emissions reasonably anticipated to contribute to visibility impairment in the same Class I Area or areas. EPA and RPOs also encourage states to consult informally with Tribes, local authorities, and any stakeholder that may desire to comment on a state's proposed approach to protecting visibility at Class I Areas.
7) EPA encourages states to consult with their respective EPA regional offices throughout the SIP planning process. This may help identify and resolve potential technical, policy, and legal issues before plan finalization and adoption by the state. This also improves the likelihood that the state will submit an approvable SIP revision. EPA recommends submission of a draft plan for review and feedback in advance of formal plan submission to EPA.
8) After public review, states hold public hearings of their air quality boards or commissions to adopt plans to implement the identified pollution control methods, make them legally binding, and thus strive to achieve visibility improvement at each Class I Area over the course of the planning period.
9) A Regional Haze SIP revision must include a progress report on past visibility trends and the implementation status of previously adopted pollution control measures to improve Class I Area visibility.

A Regional Haze SIP revision does not go into effect until EPA completes its review and approves the SIP following the state adoption process.

1.4 Overview of How this SIPr Document is Organized

This Regional Haze SIPr Rd 2 (2019-2028) is organized into twelve chapters. Each chapter presents information on a specific aspect of Regional Haze planning. Considered as a whole, the twelve chapters collectively meet Regional Haze Rule requirements for the State of New Mexico. Requirements for

[26] http://vista.cira.colostate.edu/Improve.

Albuquerque – Bernalillo County are addressed in a separate Regional Haze SIPr element, prepared by EHD and proposed to the Albuquerque-Bernalillo County AQCB.

The twelve chapters of this SIPr for the State of New Mexico cover the following topics:

- Chapter 1. Introductory material presenting an overview of the Regional Haze planning process.
- Chapter 2. An overview of the nine Class I Areas located in New Mexico, as well as the IMPROVE monitors providing data about the visibility conditions at these areas and visibility-impairing pollutants present at each area.
- Chapter 3. Detailed IMPROVE monitor data for each New Mexico Class I Area, monitoring trends analyses, and tracking visibility progress.
- Chapter 4. Provides approach of considering potentially affected Class I Areas in other states.
- Chapter 5. Progress report on implementation of the State of New Mexico Regional Haze SIP for the second half of the first Regional Haze planning period (i.e., 2014 – 2018).
- Chapter 6. A description of the process by which NMED cooperated with EHD on a common, statewide screening process to select facilities throughout New Mexico that are major sources of visibility-impairing pollutants, with a potential impact on Class I Area visibility, that would be subject to an analysis identifying potential new pollutant control measures at each facility. This process identified 24 sources total, including one source in Albuquerque – Bernalillo County.
- Chapter 7. A description of the technical analysis of potential new pollutant control measures for the 23 screened facilities outside of Albuquerque – Bernalillo County.
- Chapter 8. A description of the long-term strategy for control of visibility-impairing pollutants in the State of New Mexico during the second planning period. In the Regional Haze Rule, a long-term strategy is a set of legally enforceable control measures upon which an air quality jurisdiction (typically a state) will rely to improve visibility at Class I Areas within its borders and in other states during a Regional Haze planning period.
- Chapter 9. A description of 2028 visibility goals, which the Regional Haze Rule calls reasonable progress goals, for the nine Class I Areas in New Mexico and the relation of those goals to the long-term strategy.
- Chapter 10. Uniform rate of progress glidepath checks for the most impaired and clearest days for the nine Class I Areas in New Mexico, and additional information needed for a robust demonstration for areas that are not on the glidepath to natural visibility conditions by 2064.
- Chapter 11. A description of how NMED conducted outreach to stakeholders during preparation of this Regional Haze SIPr Rd 2 (2019-2028). This chapter also details how NMED met Regional Haze Rule requirements for consultation with FLMs who supervise the Class I Areas in New Mexico.
- Chapter 12 A final chapter addressing certain other aspects of the Regional Haze Rule, including provisions for future monitoring of visibility-impairing pollutants and future progress reports on implementation of this Regional Haze SIPr Rd 2 (2019 – 2028).

1.5 Technical Assistance from the Western Regional Air Partnership

The Western Regional Air Partnership (WRAP) is a voluntary partnership of government agencies from 15 western states involved in air quality regulation and planning. [27] WRAP members include state and

[27] WRAP membership is open to agencies located in the geographical area encompassed by the States of Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming.

local air quality regulatory agencies, Native American Tribes, EPA, and the federal land management agencies, which are the National Park Service, U.S. Forest Service, U.S. Fish and Wildlife Service, and the Bureau of Land Management. [28] As an RPO, WRAP pools and coordinates the efforts of its member agencies to provide the technical assistance necessary for them to pursue air quality regulatory initiatives, including those related to Regional Haze.

1.5.1 WRAP Role in SIP Preparation

For the current Regional Haze planning period, WRAP has provided substantial resources for use by state, local, and Tribal air quality agencies in preparing Regional Haze SIPs. These resources include quantitative data in the form of air quality monitoring results, emissions inventory estimates, and computer modeling outputs. They also include two types of written documentation: 1) technical support documents describing how the quantitative data was assembled; and 2) written guidance on approaches states may wish to take (but are not required to take) in researching and writing their Regional Haze SIPs.

WRAP is not a regulatory body, but it does play an important role in the Regional Haze process. It has no legal authority to make decisions for its members. Rather, it provides technical resources and advice to those members, based on consensus decisions among them. States may then use the resulting technical resources based on their best judgment about their own circumstances and the applicable regulatory requirements. In meeting those requirements, the Regional Haze Rule allows states to rely on the technical data and advice of WRAP and other RPOs in deciding on control measures for a Regional Haze SIP. [29] This is the key role played by WRAP. It provides data and advice that the individual air agency members would otherwise lack the staff and resources to provide for themselves.

1.5.2 WRAP Technical Support System

For the second Regional Haze planning period, WRAP prepared an online resource and data portal called the Technical Support System (TSS). [30] The TSS provides data that state, local, and Tribal air agencies may use in preparing their Regional Haze SIPs. The TSS includes air monitor data, emissions inventory data, and modeling data. Explanations and documentation of the data and the methods by which it was obtained are provided on the TSS and on the WRAP website. [31] The TSS hosts the visibility monitoring, emissions, and air quality modeling analyses that support the 15 western states in developing Regional Haze SIPs. The Emissions Methods, Results, and References document, and the Modeling Methods, Results, and References document describe the WRAP emissions and modeling analyses and illustrate how the TSS products can be applied and interpreted to support the 2028 visibility progress demonstrations for western U.S. Class I Areas. These reports are included as Appendices A and B to this Regional Haze SIPr Rd 2 (2019 – 2028).

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[28] The full list of WRAP member agencies is available at https://westar.org/wrap-council-members/.

[29] 40 CFR § 51.308(f)(2)(iii). WRAP is one of five U.S. regional planning organizations that assist states in preparing Regional Haze SIPs. See https://www.epa.gov/visibility/visibility-regional-planning-organizations.

[30] The TSS is available online at https://views.cira.colostate.edu/tssv2/default.aspx. The TSS for the current planning period is the second version (v2) of the TSS.

[31] The WRAP Regional Haze Planning Work Group web page provides thorough documentation of the process by which WRAP collated and generated data for air quality monitoring, emissions, and modeling. See the links and documents available at https://westar.org/regional-haze-planning-work-group/. Important technical documentation of WRAP Regional Haze planning also appears on the organization's Regional Tech Operations Work Group web page, available at https://westar.org/regional-tech-operations-work-group/.

1.6 Supplementary Data from non-WRAP Sources

This Regional Haze SIPr Rd 2 (2019-2028) also relies on data from sources other than WRAP. These will be noted in specific chapters/appendices, as appropriate.

1.7 Joint Regional Haze Planning by NMED and EHD

Because of the scope and design of the Regional Haze Rule, NMED prepared this Regional Haze SIPr Rd 2 (2019-2028) in close cooperation with EHD. Under state and local law, EHD prepares SIPs applicable to the City of Albuquerque and Bernalillo County, proposing these for consideration by the Albuquerque - Bernalillo County AQCB. [32] Separately, NMED prepares SIPs for the rest of the state and proposes these plans for consideration by the EIB. [33]

Subsequent chapters of this SIPr element will describe in detail the statewide Regional Haze analytical framework. This SIPr element should be read in conjunction with the SIPr element prepared by EHD for the City of Albuquerque and Bernalillo County.

1.8 Role of NMED

State law requires NMED to develop SIPs and SIP revisions for proposal to the EIB. [34] In accordance with that requirement, NMED staff developed and wrote this Regional Haze SIPr Rd 2 (2019-2028) and proposed it for consideration by the EIB in the form of a request for a formal, public hearing to consider the plan. [35] If the EIB adopts this Regional Haze SIPr Rd 2 (2019-2028), the Board will authorize NMED to submit the plan to EPA in accordance with EPA regulations.

This Regional Haze SIPr Rd 2 (2019-2028), developed and proposed by NMED, is a narrative document describing how the state will meet federal regulatory requirements in the Regional Haze Rule at 40 CFR §§ 51.308 and 51.309. This SIPr is not in itself an enforceable regulation, but it is legally mandatory for the state to submit it to EPA in order to meet the federal regulatory requirements.

1.9 Role of the New Mexico Environmental Improvement Board

The New Mexico Air Quality Control Act requires the EIB to promulgate air quality regulations [36] and adopt a plan for the "regulation, control, prevention, or abatement of air pollution." [37] The Board may also adopt regulations "to protect visibility in mandatory class I areas." [38] These regulatory provisions provide authority for the Board to consider the Regional Haze SIPr Rd 2 (2019 – 2028) proposed by NMED, including any new or amended legally enforceable regulations necessary to implement the SIP, in order to meet federal Regional Haze Rule requirements.

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[32] NMSA 1978 §§ 74-2-5 and 74-2-5.1; ROA 1994 §§ 9-5-4 and 9-5-1-5; Bernalillo County Code §§ 30-33 and 30-34.
[33] NMSA 1978 §§ 74-2-5 and 74-2-5.1.
[34] NMSA 1978 § 74-2-5. The language in this section requires NMED to develop an air quality "plan" but, in practice, NMED develops many different plans that collectively satisfy the requirement of the federal Clean Air Act for a single SIP. *See* 42 U.S.C. § 7410.
[35] State law governing the conduct of an air quality rulemaking hearing is at NMSA 1978 § 74-2-6. The regulation governing NMED's request for a rulemaking hearing by the Environmental Improvement Board is 20.1.1 NMAC, *Rulemaking Procedures -- Environmental Improvement Board*.
[36] NMSA 1978 § 74-2-5(B)(1).
[37] NMSA 1978 § 74-2-5(B)(2).
[38] NMSA 1978 § 74-2-5(D)(1).

In considering a proposed SIP or SIPr and any accompanying proposed regulations, the EIB must "give weight it deems appropriate to all facts and circumstances," including facts and circumstances specified in the state Air Quality Control Act, related to the following:

1) "character and degree of injury to or interference with . . . visibility;" [39]
2) "social and economic value of the sources and subjects of air contaminants;" [40] and
3) "technical practicability and economic reasonableness" of emission reduction measures, with consideration of previous experience and available methods. [41]

Under state law, any emission control requirement, such as those contained in this Regional Haze SIPr Rd 2 (2019 – 2028), may be adopted by the EIB only after a duly noticed public hearing. [42] Regulations or emission control requirements adopted based on a rulemaking hearing cannot become effective until 30 days after filing with the State Records Center and Archives in accordance with the State Rules Act. [43] A rulemaking hearing must be held in accordance with procedural requirements in the state Air Quality Control Act [44] and the Board's regulation governing such hearings. [45]

1.10 Role of the U.S. EPA

This Regional Haze SIPr Rd 2 (2019-2028) is subject to several federal regulatory requirements implemented and enforced by EPA.

1) The Regional Haze Rule requires submittal of this SIPr to EPA, [46] with content in the SIPr that addresses specific requirements. [47]
2) The public rulemaking hearing held by the EIB to consider this SIPr must be held only after reasonable notice provided at least 30 days prior to the date of the hearing. [48]
3) The State of New Mexico must submit this SIPr to EPA with appropriate documentation, including documentation of the public hearing in accordance with federal, state, and local law. [49]

After a state submits a SIP to EPA, EPA has six months to certify that a state has made a complete submittal. [50]

Failure to submit an approvable Regional Haze SIPr Rd 2 (2019-2028) to EPA may result in federal action against the State of New Mexico. If a state fails to submit a SIP, EPA has until six months after the

[39] NMSA 1978 § 74-2-5(F)(1).
[40] NMSA 1978 § 74-2-5(F)(2).
[41] NMSA 1978 § 74-2-5(F)(3).
[42] NMSA 1978 § 74-2-6(B) and (C).
[43] NMSA 1978 § 74-2-6(F).
[44] NMSA 1978 § 74-2-6(A), (D), and (E).
[45] 20.1.1 NMAC, Rulemaking Procedures -- Environmental Improvement Board.
[46] 40 CFR § 51.308(f).
[47] 40 CFR §§ 51.308(f)(1) to (f)(6), 51.308(g), and 51.309.
[48] 40 CFR § 51.102(d). Note that the Board's regulation governing rulemaking hearings requires that notice be given at least 60 days prior to the date of the hearing. *See* Subsection A of 20.1.1.301 NMAC.
[49] 40 CFR § 51.103 and 40 CFR Part 51, Appendix V.
[50] 42 U.S.C. § 7410(k)(1)(B).

deadline for submittal to make a finding of failure to submit.[51] EPA must, within two years of such a finding, approve a SIP or issue a Federal Implementation Plan (FIP) that accomplishes the purposes for which the SIP should have been submitted.[52] In the case of the Regional Haze Rule, EPA may issue a FIP that unilaterally imposes Regional Haze control measures on facilities in the State of New Mexico in order to protect visibility at Class I Areas.

[51] 42 U.S.C. § 7410(k)(1)(B). EPA has already issued a finding of failure to submit second period Regional Haze SIPs for 15 states, including New Mexico. 87 Fed. Reg. 52856 (Aug. 30, 2022) (Finding of Failure to Submit Regional Haze State Implementation Plans for the Second Planning Period).

[52] 42 U.S.C. § 7410(c)(1). The current deadline for EPA to approve a Regional Haze SIP or issue a FIP for New Mexico is September 29, 2024.

Chapter 2: New Mexico Class I Areas and IMPROVE Monitor Sites

This chapter provides a brief description of the Interagency Monitoring of Protected Visual Environments ("IMPROVE") monitoring network, followed by an overview of New Mexico's nine Class I Areas and the eight IMPROVE monitor sites that provide visibility-related data for those areas.

2.1 IMPROVE Monitoring Network

The IMPROVE program is a cooperative measurement effort governed by a steering committee from federal, regional, and state organizations. The program was established in 1985 to aid the creation of Federal and State Implementation Plans for the protection of visibility in Class I Areas, as stipulated in the 1977 amendments to the Clean Air Act and expanded upon in the 1990 amendments. As required by the Act, as amended, the U.S. Environmental Protection Agency (EPA) promulgated regulations designating 156 national parks and wilderness areas as Class I Areas. The IMPROVE monitoring network began operating in 1988 with 20 monitor sites in Class I Areas and has subsequently grown to 110 monitor sites sponsored by the Federal Land Managers (FLMs) plus an additional 48 "protocol sites" sponsored by state, regional, Tribal, and national organizations that provide expanded spatial coverage for the network. [53]

The IMPROVE monitoring network consists of individual monitor sites across the United States containing aerosol speciation samplers, which measure the types, i.e., "species," and amounts of visibility-impairing pollutants present in the air in or around Class I Areas. A small number of IMPROVE monitor sites, in addition to measuring the type and amount of pollutants, also perform direct optical measurements of visibility impairment.

The regulatory objectives of the IMPROVE monitoring network are: [54]

- to establish current visibility and aerosol conditions in Class I Areas;
- to identify chemical species responsible for existing man-made visibility impairment, thereby allowing inference of emission sources for those species;
- to document long-term trends for assessing progress towards the Clean Air Act's national visibility goal, which is returning Class I Areas to natural visibility conditions; and,
- beginning with the EPA's enactment of the Regional Haze Rule in 1999, to provide regional haze monitoring representing all visibility-protected Class I Areas, using specific metrics and approaches defined in the Rule.

It is important to note that not every Class I Area has its own monitor. Sometimes, practicality requires that a single monitor provide representative data for more than one Class I Area. As discussed later in this chapter, IMPROVE monitor site WHPE1 provides data for two New Mexico Class I Areas, Pecos Wilderness Area and Wheeler Peak Wilderness Area. All other Class I Areas in New Mexico currently have their own monitors.

[53] *See* http://vista.cira.colostate.edu/Improve/improve-program/. *See also* http://vista.cira.colostate.edu/improve/wp-content/uploads/2022/09/IMPROVE_Sites_Active_Updated_September_2022.xlsx (current site list spreadsheet).
[54] https://vista.cira.colostate.edu/improve/wp-content/uploads/2023/01/IMPROVE-Charter.pdf.

In addition to the above regulatory functions, the IMPROVE program has also been a key participant in visibility-related research, including the advancement of monitoring instrumentation, analysis techniques, visibility modeling, policy formulation, and source attribution field studies.

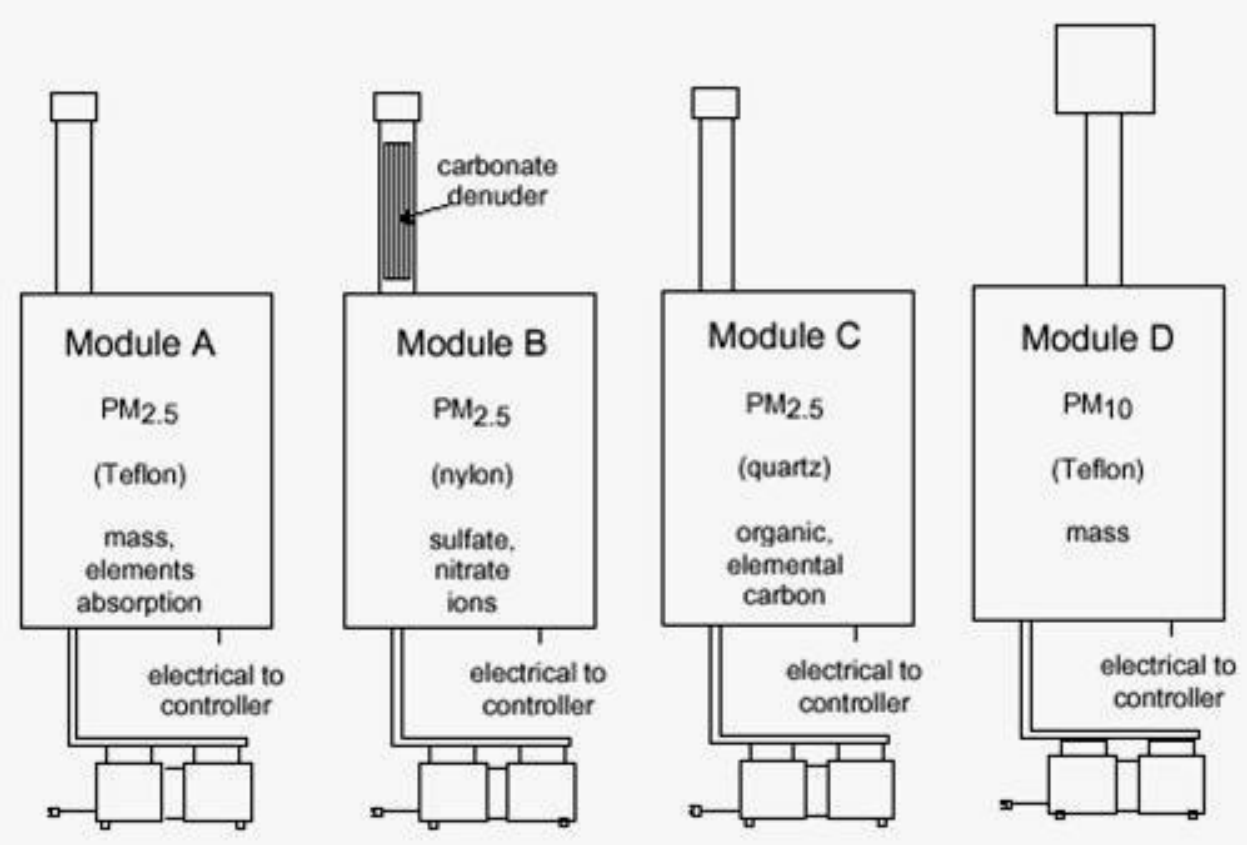
Figure 2-1 shows a typical IMPROVE monitor site, in this case located at Bosque del Apache Wilderness Area, which is one of the nine Class I Areas in New Mexico. Like the other IMPROVE monitor sites, the one at Bosque del Apache contains four separate modules used for sampling the particulate species responsible for visibility impairment, as diagrammed in Figure 2-2. Each module consists of a size-cut filter cassette with appropriate filter material for species of interest, flow control, and a sample pump. IMPROVE samplers collect 24-hour samples, every three days. The collected filter samples are subsequently analyzed at the UC-Davis Crocker Nuclear Laboratory and other analytical laboratories for the indicated particulate species.

Figure 2-1: IMPROVE Monitor Site at Bosque del Apache Wilderness Area.



Photo credit: Kip Carrico

Figure 2-2: Four Aerosol Modules Used for Regional Haze Monitoring at IMPROVE Monitor Sites.



For purposes of this Regional Haze SIPr Rd 2 (2019 – 2028), the primary point of note here is that IMPROVE monitor sites provide technically reliable information about visibility conditions and causes of visibility interference for each Class I Area, by methods that meet all applicable federal regulatory requirements. Chapter 3 of this SIPr provides additional technical details on how the IMPROVE network carries out this function.

2.2 New Mexico Class I Areas and IMPROVE Monitor Sites

Table 2-1 lists the eight IMPROVE monitor sites that collect regional haze monitoring data for New Mexico's nine Class I Areas.[55] Note that the IMPROVE monitor for Wheeler Peak Wilderness Area is also used to represent visibility conditions at nearby Pecos Wilderness Area. Note too that the IMPROVE monitor for Carlsbad Caverns National Park is located in Texas at Guadalupe Mountains National Park. Figure 2-3 shows the locations of the eight IMPROVE monitors listed in Table 2-1 (and new monitor site CAVE1) relative to their associated Class I Areas. Each individual Class I Area in New Mexico is discussed further below.

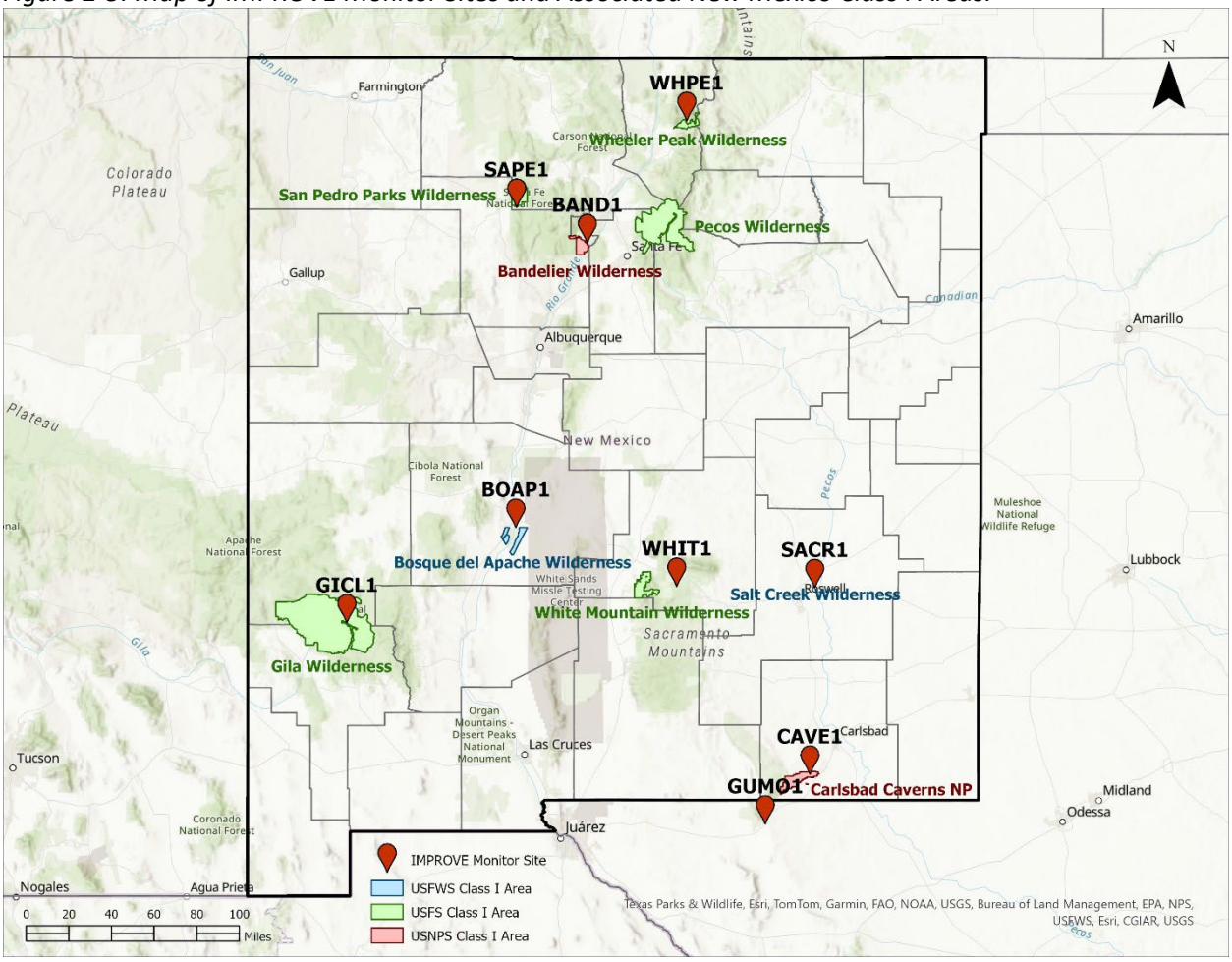
[55] A new monitor site (CAVE1) was recently established closer to Carlsbad Caverns National Park but is not considered here because data collection only began in 2017. Likewise, one past New Mexico monitoring site (SAAN1) only operated from 1997-1999 and is not considered here because that data predates the time period covered by the Regional Haze Rule (2000-2064).

Table 2-1: IMPROVE Monitoring Network and Associated Class I Areas in New Mexico.

Site Name	Site Code and Geographic Coordinates	Location (County)	Associated Class I Area	Federal Land Manager	Elevation (feet) [1]	Start Date
Bandelier	BAND1 35.7797° N 106.2664° W	Los Alamos	Bandelier Wilderness Area	U.S. National Park Service (USNPS)	6,523	March 1988
Bosque del Apache	BOAP1 33.8695° N 106.852° W	Socorro	Bosque del Apache Wilderness Area	U.S. Fish and Wildlife Service (USFWS)	4,560	April 2000
Gila	GICL1 33.2204° N 108.2351° W	Catron	Gila Wilderness Area	U.S. Forest Service (USFS)	5,825	April 1994
Guadalupe Mountains (TX)	GUMO1 31.833° N 104.8094° W	Culberson (TX)	Carlsbad Caverns National Park	USNPS	5,486	March 1988
Salt Creek Wilderness	SACR1 33.4598° N 104.4042° W	Chaves	Salt Creek Wilderness Area	USFWS	3,518	April 2000
San Pedro Parks	SAPE1 36.0139° N 106.8447° W	Rio Arriba	San Pedro Parks Wilderness Area	USFS	9,629	August 2000
Wheeler Peak	WHPE1 36.5854° N 105.452° W	Taos	Wheeler Peak Wilderness Area, Pecos Wilderness Area	USFS	11,043	August 2000
White Mountain	WHIT1 33.4687° N 105.5349° W	Lincoln	White Mountain Wilderness Area	USFS	6,770	January 2002

[1] Datum = mean sea level.

Figure 2-3: Map of IMPROVE Monitor Sites and Associated New Mexico Class I Areas.



The earliest New Mexico IMPROVE monitor sites, Bandelier and Guadalupe Mountains, have been active since the start of the IMPROVE program in 1988. Several New Mexico monitor sites became operational after January 1, 2000 (start dates are provided in Table 2-1); all, however, are considered by EPA to have complete data records as discussed in Chapter 3. The data from these sites provides a comprehensive record of visibility conditions in the Class I Areas of New Mexico.

2.2.1 Bandelier Wilderness Area

The Bandelier Wilderness Area encompasses approximately 90 percent of Bandelier National Monument, which sits at the southern end of the Pajarito Plateau. The plateau was formed by two eruptions 1.6 and 1.4 million years ago. Elevations at Bandelier range from 5,340 feet at the Rio Grande River to the south to 10,199 feet at the summit of Cerro Grande to the north, which is almost a mile of elevation change in just under 12 miles. This large elevation gradient creates a unique diversity of habitats specific to northern New Mexico. The diversity of habitats and quick access to water supported a relatively large population of ancestral Pueblo peoples. Currently, piñon-juniper woodlands dominate in the southern parts of the monument, transitioning through ponderosa pine savannahs and forests, finally reaching mixed conifer forests at the highest elevations. Scattered throughout the monument are desert grasslands, montane meadows, and riparian areas in the canyon bottoms. Bandelier is home

to a wide variety of wildlife. The backcountry trails at Bandelier climb in and out of deep canyons and cross large flat mesas, showcasing the entire spectrum of volcanic geology.

Additional information about Bandelier is available from the National Park Service at https://www.nps.gov/band/index.htm.

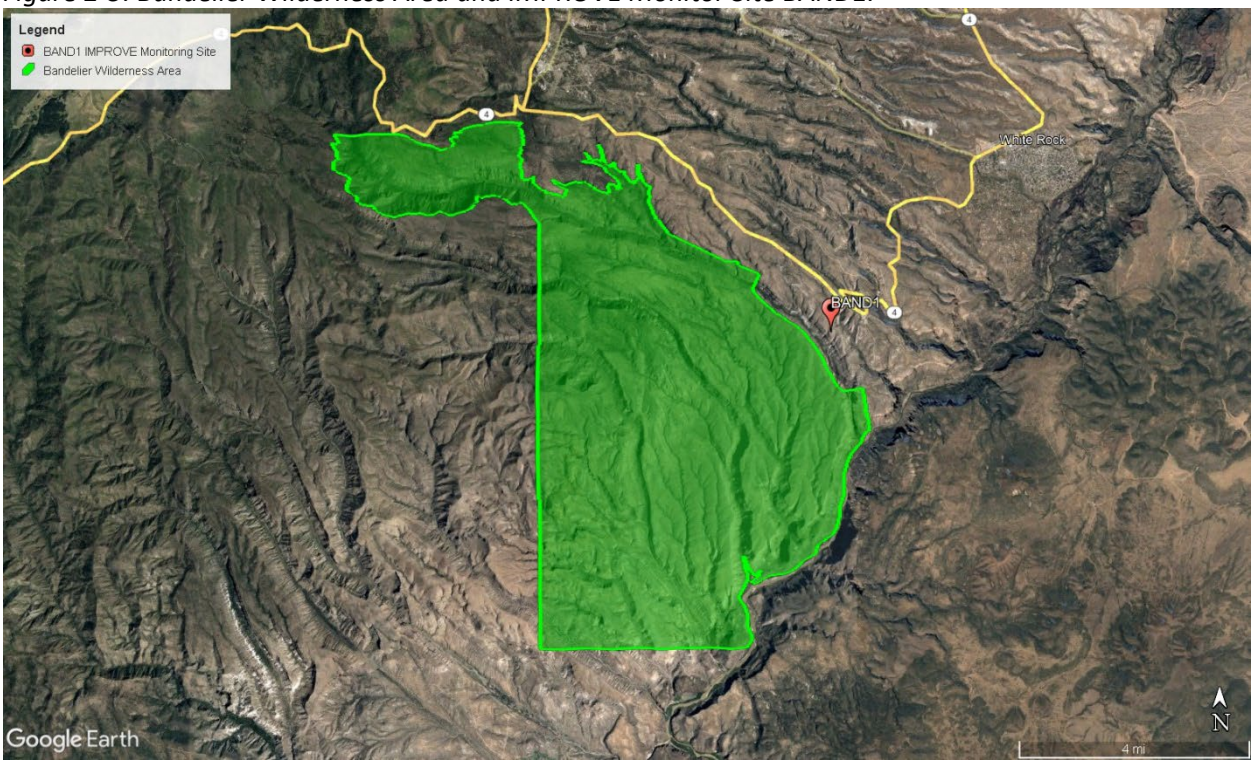
Figure 2-4: Bandelier Wilderness Area in Sandoval, Los Alamos, and Santa Fe Counties, NM.



Photo credit: Kip Carrico.

The IMPROVE monitor site for Bandelier Wilderness Area is BAND1, located near a fire tower on a ridge crest just outside of the eastern Wilderness boundary at an elevation of 6,523 feet. The BAND1 IMPROVE monitor site is in an exposed location at an elevation near the middle of the range of Wilderness elevations and about 1,000 feet above the Rio Grande River at the bottom of the canyon. The highest Bandelier Wilderness Area elevations are typically about 1,000 feet above the monitor site. As a result, BAND1 is considered representative of visibility conditions within Bandelier Wilderness Area.

Figure 2-5: Bandelier Wilderness Area and IMPROVE Monitor Site BAND1.



2.2.2 Bosque del Apache Wilderness Area

The Bosque del Apache Wilderness Area consists of three separate units within the larger Bosque del Apache National Wildlife Refuge (NWR), which is located along the Rio Grande River south of Socorro, New Mexico. The refuge is located at the northern edge of the Chihuahuan Desert and straddles the river. The heart of the refuge is about 12,900 acres of moist bottomlands – 3,800 acres are active floodplain, and 9,100 acres are areas where water is diverted to create extensive wetlands, farmlands, and riparian forests. The rest of Bosque del Apache NWR is made up of arid foothills and mesas, which rise to the Chupadera Mountains to the west and the San Pascual Mountains to the east. Most of these desert lands are preserved as wilderness areas.

Managed by the U.S. Fish and Wildlife Service, Bosque del Apache NWR is an important link in the more than 500 federal wildlife refuges in North America. The goal of refuge management is to provide habitat and protection for migratory birds and endangered species and provide the public with a high-quality wildlife and educational experience.

Additional information about Bosque del Apache is available from the U.S. Fish and Wildlife Service at https://www.fws.gov/refuge/bosque_del_apache/.

Figure 2-6: Bosque del Apache Wilderness Area in Socorro County, NM.

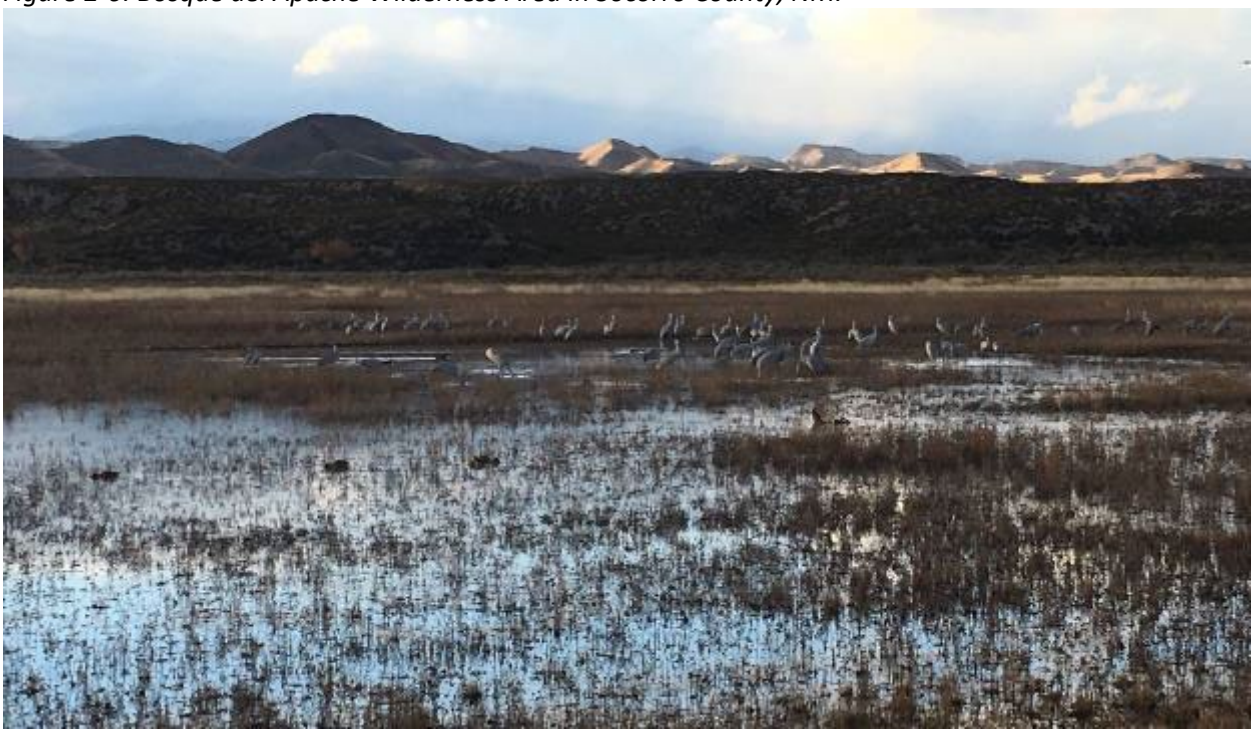
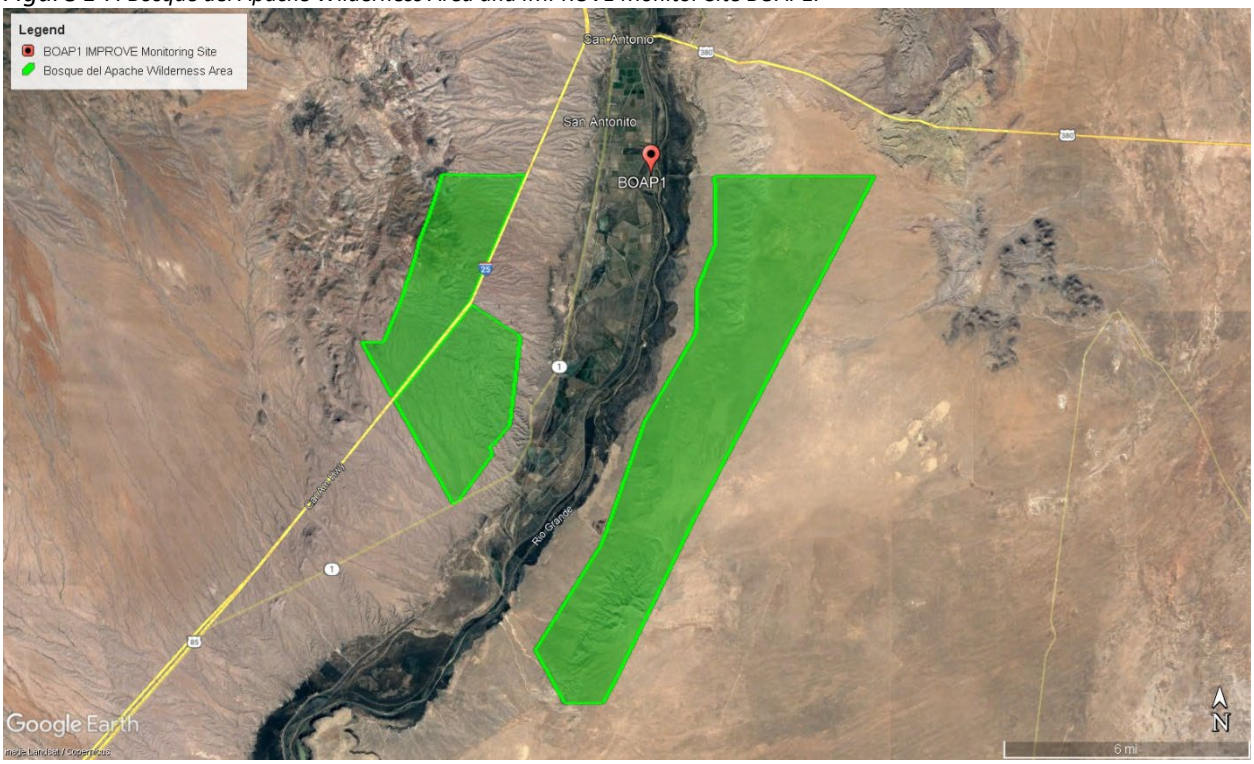


Photo credit: Kip Carrico

The IMPROVE monitor site for Bosque del Apache Wilderness Area is BOAP1, located at the northern boundary near the Rio Grande River at an elevation of 4,560 feet. Given the narrow range of elevations at Bosque del Apache, BOAP1 is considered representative of visibility conditions there.

Figure 2-7: Bosque del Apache Wilderness Area and IMPROVE Monitor Site BOAP1.



2.2.3 Carlsbad Caverns National Park

Carlsbad Caverns National Park is located in the Guadalupe Mountains, a mountain range that runs from west Texas into southeastern New Mexico. The most famous of all the geologic features in the park are the more than 110 limestone caves, the most well-known of which is Carlsbad Caverns. Carlsbad Caverns receives more than 300,000 visitors each year and offers a rare glimpse of the underground worlds preserved under the desert above.

Elevations within the park rise from 3,595 feet in the lowlands to 6,520 feet atop the escarpment. Though there are scattered woodlands in the higher elevations, the park is primarily a variety of grassland and desert shrub land habitats. The park supports a diverse ecosystem, including habitat for many plants and animals that are at the geographic limits of their ranges. For example, the ponderosa pine reaches its extreme eastern limit here and several species of reptiles are at the edges of their distributions.

Additional information about Carlsbad Caverns is available from the National Park Service at https://www.nps.gov/cave/index.htm.

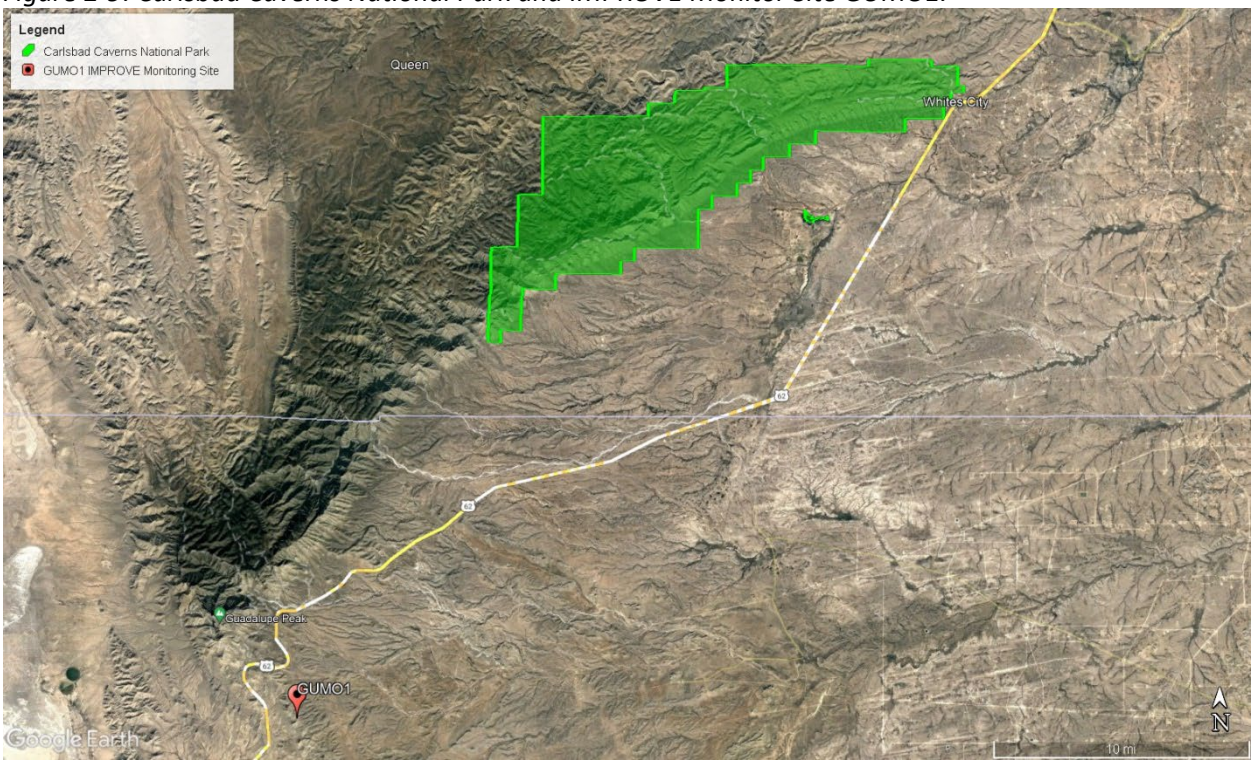
Figure 2-8: Carlsbad Caverns National Park in Eddy County, NM.



Photo credit: National Park Service (https://www.nps.gov/im/chdn/cave.htm).

The IMPROVE monitor site for Carlsbad Caverns National Park is GUMO1, located about 15 miles southwest in mountainous terrain near the crest of the Delaware Mountain Range at an elevation of 5,486 feet. It has good exposure to regional-scale winds and may be influenced by wind-blown dust from the salt flats in western Texas, as well as from the Mexican dry/barren region to the southwest. The ground cover near the monitor site is desert vegetation (e.g., shrubland and grassland). As a result, GUMO1 is considered representative of visibility conditions within Carlsbad Caverns National Park, especially at higher elevations.

Figure 2-9: Carlsbad Caverns National Park and IMPROVE Monitor Site GUMO1.



2.2.4 Gila Wilderness Area

The Gila Wilderness Area in southwestern New Mexico incorporates varied terrain. The northeastern and far eastern sections of the wilderness consist of high mesas and rolling hills, ranging in elevation from approximately 5,000 to 8,000 feet and cut by the deep canyons of the Gila River. The vegetation consists primarily of mixed junipers and piñon pines, grasses, and at the higher elevations and on northern slopes, ponderosa pines, vast stands of which cover the central part of the Gila. The river canyons offer spectacular cliffs, with mixed hardwoods and ponderosa pine growing along the riparian bottoms. The far western and southwestern sections of the Gila consist of high mountains, with the highest elevation reaching 10,895 feet in the Mogollon Range. Steep side canyons are common, and vegetation includes Douglas fir, ponderosa pine, aspen, and a variety of ferns. The area includes the drainage basins of both Mogollon Creek and Turkey Creek.

Additional information about the Gila is available from the U.S. Forest Service at https://www.fs.usda.gov/gila/.

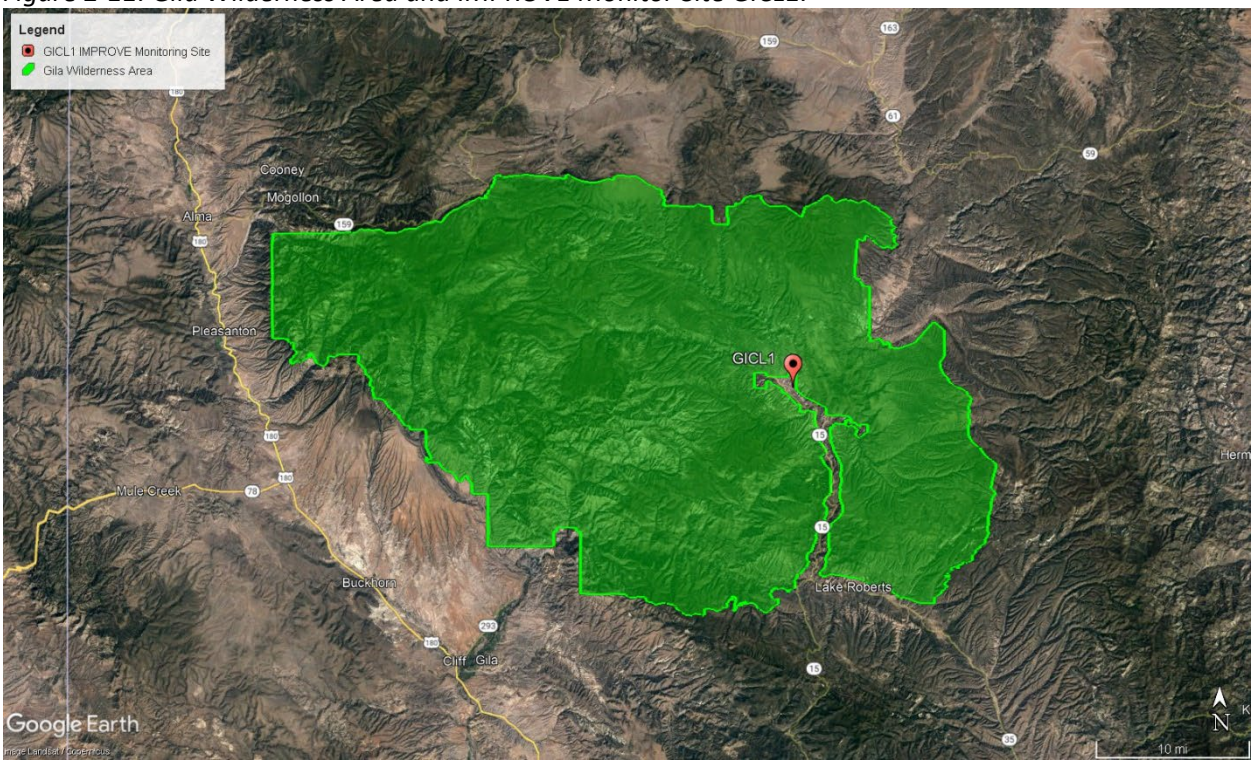
Figure 2-10: Gila Wilderness Area in Grant and Catron Counties, NM.



Photo credit: Elizabeth Sorells.

The IMPROVE site for the Gila Wilderness Area is GICL1, located on a bank overlooking the Gila River in the east-central part of the Wilderness at an elevation of 5,825 feet. As a result of its location near the center of the Wilderness, GICL1 is considered representative of visibility conditions within the area.

Figure 2-11: Gila Wilderness Area and IMPROVE Monitor Site GICL1.



2.2.5 Pecos Wilderness Area

The Pecos Wilderness Area extends through two Ranger Districts in the Santa Fe National Forest and into the Carson National Forest to the north. Within the boundaries of this expansive area are several landmarks including Truchas Peak, which tops out at 13,103 feet, and the southern stretch of the Rocky Mountains. The terrain varies from open meadows in the Pecos River Valley to the steep canyons of the Sangre de Cristo Mountain Range. Wildlife ranges from deer and elk to bighorn sheep, turkeys, and grouse. There are 15 lakes and eight major streams that sustain both plant and animal habitats, including for the native Rio Grande Cutthroat Trout.

Additional information about the Pecos is available from the U.S. Forest Service at https://www.fs.usda.gov/detail/santafe/ and https://www.fs.usda.gov/detail/carson/.

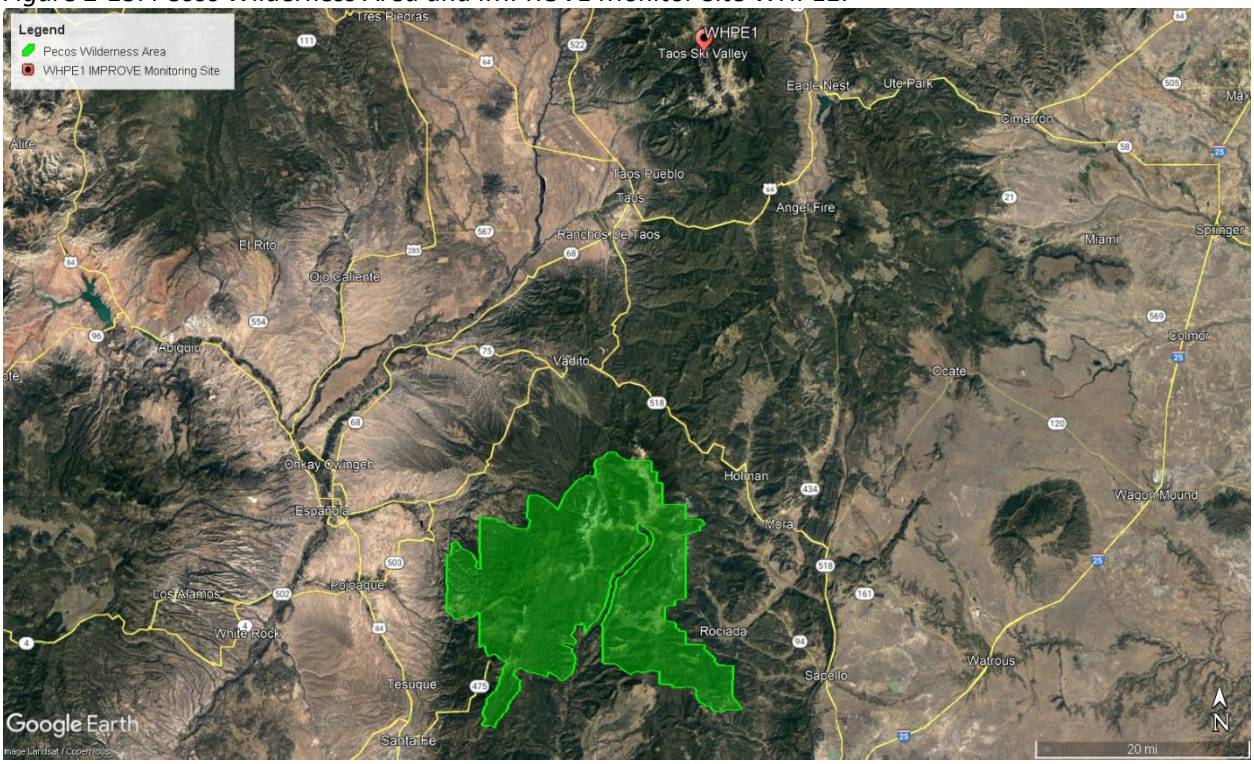
Figure 2-12: Pecos Wilderness Area in Mora, Rio Arriba, San Miguel, Santa Fe, and Taos Counties, NM.



Photo credit: Santa Fe National Forest.

The IMPROVE monitor site for Pecos Wilderness Area is WHPE1, located about 40 miles to the north near Wheeler Peak Wilderness Area at an elevation of 11,043 feet. Because it is at a high elevation, WHPE is considered representative of visibility conditions at high elevations of the Sangre de Cristo Mountains, including the Pecos Wilderness Area.

Figure 2-13: Pecos Wilderness Area and IMPROVE Monitor Site WHPE1.



2.2.6 Salt Creek Wilderness Area

The Salt Creek Wilderness Area is part of the Bitter Lake National Wildlife Refuge. Salt Creek Wilderness Area consists of river bottomlands, grasslands, sand dunes, and mixed shrub communities and comprises the watershed of Salt Creek, which empties into the Pecos River in southeastern New Mexico. The refuge, Bitter Lake, is located near Roswell, New Mexico, immediately west of the Pecos River. Virtually no waterfowl or water birds use the wilderness portion of the refuge because it is devoid of wetlands other than the river and a dozen sinkholes. Two or three of the sinkholes contain rare fish: the Pecos gambusia, which is endangered, and the Pecos pupfish, a species of concern. Part of the reason Salt Creek was established as wilderness was to protect the scenic red bluffs on the north side of Salt Creek.

Further information about Salt Creek is available from the U.S. Fish and Wildlife Service at https://www.fws.gov/refuge/bitter_lake/.

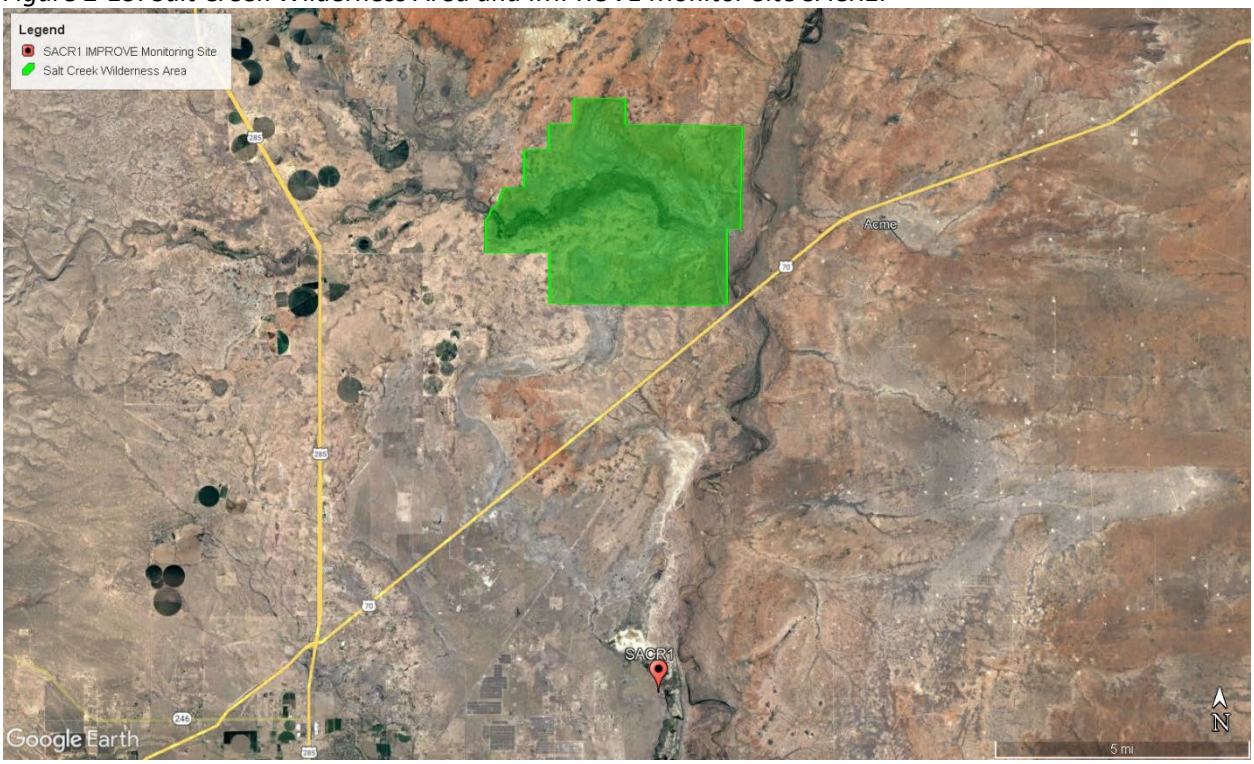
Figure 2-14: Salt Creek Wilderness Area in Chaves County, NM.



Photo credit: Jeff Howland (https://wilderness.net/).

The IMPROVE monitor site for Salt Creek Wilderness Area is SACR1, located about 6 miles south of the Wilderness at an elevation of 3,518 feet. SACR1 is considered representative of visibility conditions in the Salt Creek Wilderness Area since it is at the same elevation with no intervening terrain.

Figure 2-15: Salt Creek Wilderness Area and IMPROVE Monitor Site SACR1.



2.2.7 San Pedro Parks Wilderness Area

The San Pedro Parks Wilderness Area is on the western edge of the Santa Fe National Forest and part of the Colorado Plateau. It occupies 41,132 acres in Southern Rio Arriba County, New Mexico. It is an alpine site with stands of Engelmann spruce, mixed conifers, and aspen punctuated by grassy meadows. Due to its elevation, approximately 10,000 feet on average, it experiences significant rainfall, particularly in the monsoon season of July - August. It has streams that are abundant with trout and standing bodies of water including the San Gregorio Reservoir. The Wilderness is crossed by the Continental Divide National Scenic Trail.

Additional information about San Pedro Parks is available from the U.S. Forest Service at https://www.fs.usda.gov/detail/santafe/about-forest/districts/?cid=fsbdev7_021062".

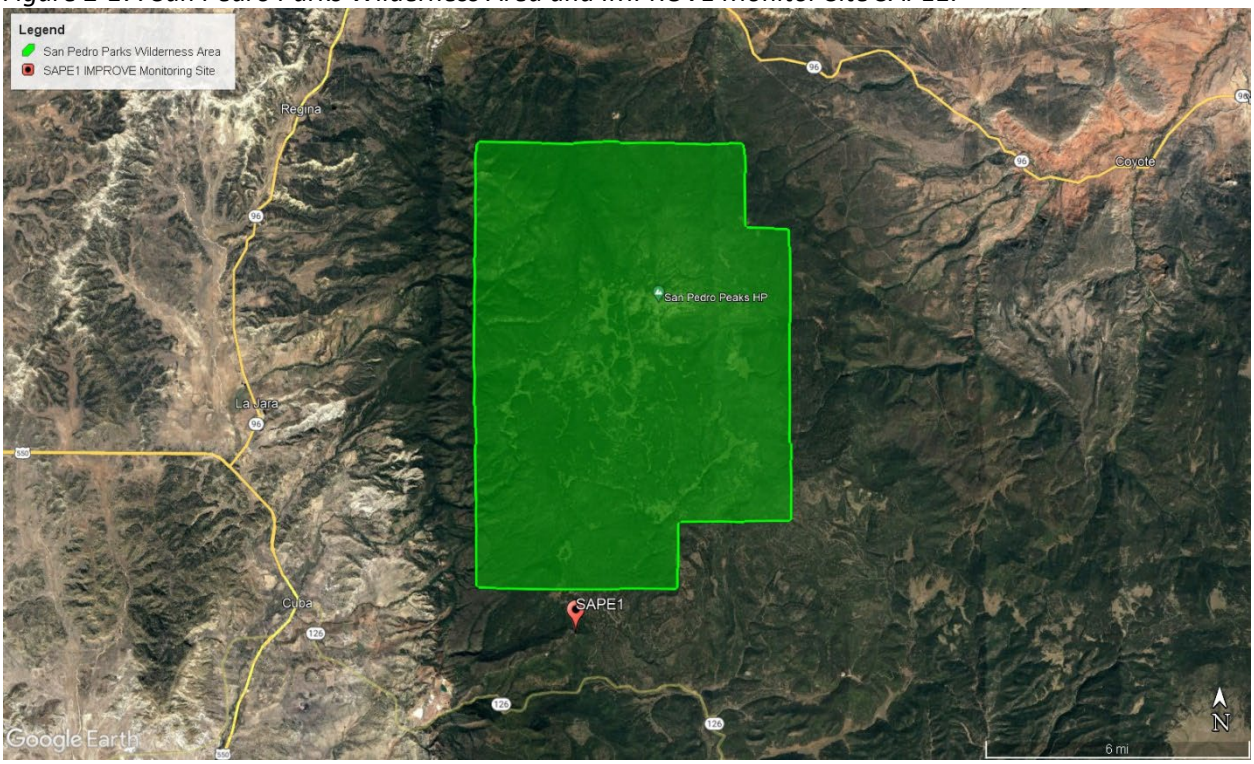
Figure 2-16: San Pedro Parks Wilderness Area in Southern Rio Arriba County, NM.



Photo Credit: Kerry Jones, USFS.

The IMPROVE monitor site for San Pedro Parks Wilderness Area is SAPE1, located on a peak approximately 6 miles due east of Cuba, New Mexico at an elevation of 9,629 feet. It is in the middle of the altitude range of the Wilderness and thus is considered representative of Wilderness visibility conditions.

Figure 2-17: San Pedro Parks Wilderness Area and IMPROVE Monitor Site SAPE1.



2.2.8 Wheeler Peak Wilderness Area

Lying along the top of the Sangre De Cristo Mountain Range, Wheeler Peak Wilderness Area is characterized by high rugged terrain. Elevations range from a low of 7,650 feet to a high of 13,161 feet at Wheeler Peak, the highest point in the State of New Mexico. Marmots, pikas, elk, mule deer, and golden eagles are found in the Wheeler Peak Wilderness. Above Taos Ski Valley, the Rio Hondo has a natural population of cutthroat trout as does Sawmill Creek. From the cottonwoods along the Rio Hondo to the Bristlecone pines guarding the peaks, Wheeler Peak Wilderness has almost all of the trees native to Northern New Mexico. Engelmann spruce and sub-alpine fir are the predominant tree species. Because Wheeler Peak is so high, it is one of the only places in the state to see a true alpine "mat" as opposed to grasses that grow in other high alpine locales. The "mat" produces beautiful brilliantly colored flowers. The average annual precipitation is 34-40 inches, with about half from summer rains and half from winter snows. Average annual temperatures range between 80° Fahrenheit in the summer to -20° Fahrenheit in the winter.

Additional information about the Wheeler Peak Wilderness is available from the U.S. Forest Service at https://www.fs.usda.gov/detail/carson/.

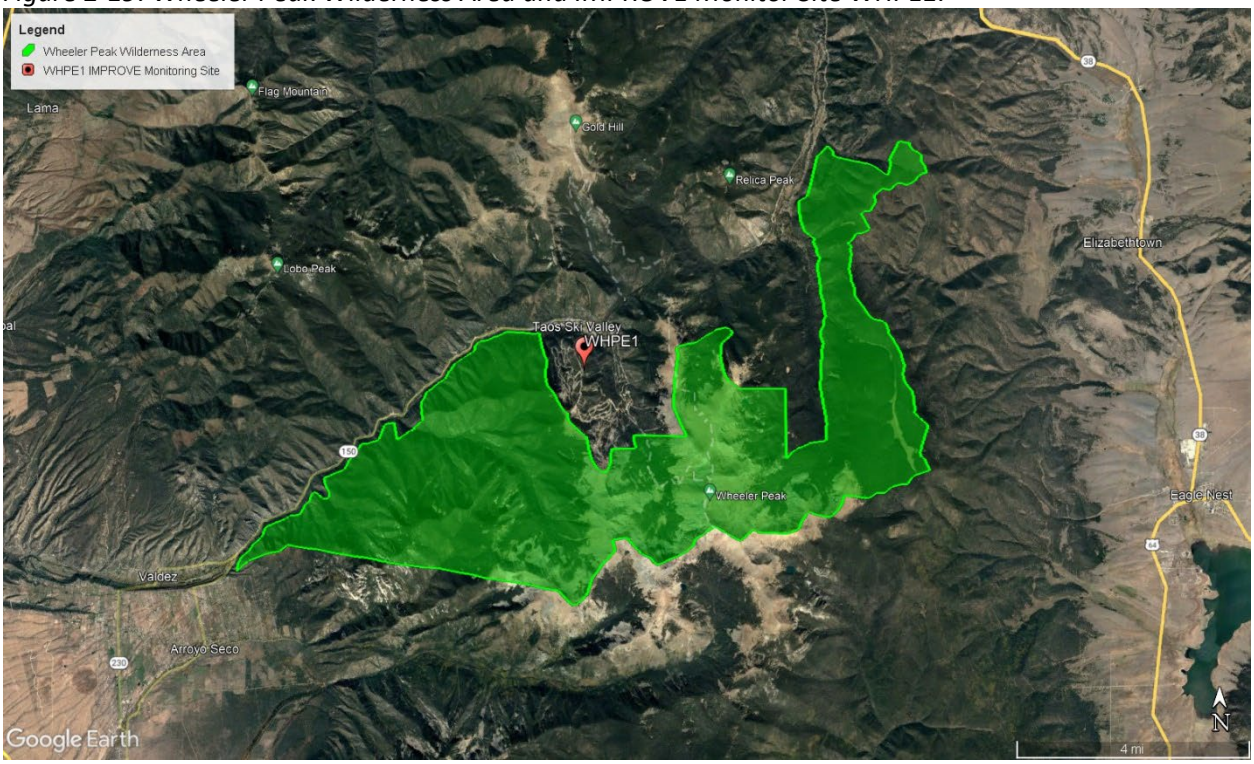
Figure 2-18: Wheeler Peak Wilderness Area in Taos County, NM.



Photo credit: Mark Jones, NMED.

The IMPROVE monitor site for Wheeler Peak Wilderness Area is WHPE1, located at a high point just outside the northern Wilderness boundary at an elevation of 11,043 feet. Because it is at a high elevation, WHPE is considered representative of visibility conditions at high elevations of the Sangre de Cristo Mountains, including the Wheeler Peak Wilderness Area.

Figure 2-19: Wheeler Peak Wilderness Area and IMPROVE Monitor Site WHPE1.



2.2.9 White Mountain Wilderness Area

The White Mountain Wilderness Area lies entirely within the Smokey Bear Ranger District of the Lincoln National Forest. The Wilderness is 12.5 miles long and ranges from 4 to 12 miles wide. The Wilderness consists mainly of a long, northerly running ridge and its branches. The west side of the ridge is steep and extremely rugged with many extensive rock outcroppings. The east side is gentler with broader, forested canyons and a few small streams. Elevations range from a low of 6,400 feet at Three Rivers Campground on the west side to a high of 11,580 feet near Lookout Mountain on the south. From Three Rivers to the crest there are four different life zones: piñon-juniper, ponderosa pine, mixed conifer, and sub-alpine forest. Abrupt changes in elevation, escarpments, rock outcrops, and avalanche chutes make for striking contrast and scenery. Interspersed along the crest are several meadows as well as some grass-oak savannahs, which are the result of fires.

Springtime is usually dry and windy throughout the Wilderness. July and August are the rainy months with frequent afternoon showers. In summer, while the desert is sweltering, the high country will likely be cool. Oak, maple and aspen on hillsides feature striking color changes in the autumn when days are usually cool and sunny with little wind. Winter snowfall usually begins in mid- to late November and can continue through June. During the winter months, the higher elevations may be under six or more feet of snow while it is above freezing at lower elevations.

Additional information about White Mountain Wilderness is available from the U.S. Forest Service at https://www.fs.usda.gov/main/lincoln/home.

Figure 2-20: White Mountain Wilderness Area in Lincoln County, NM.

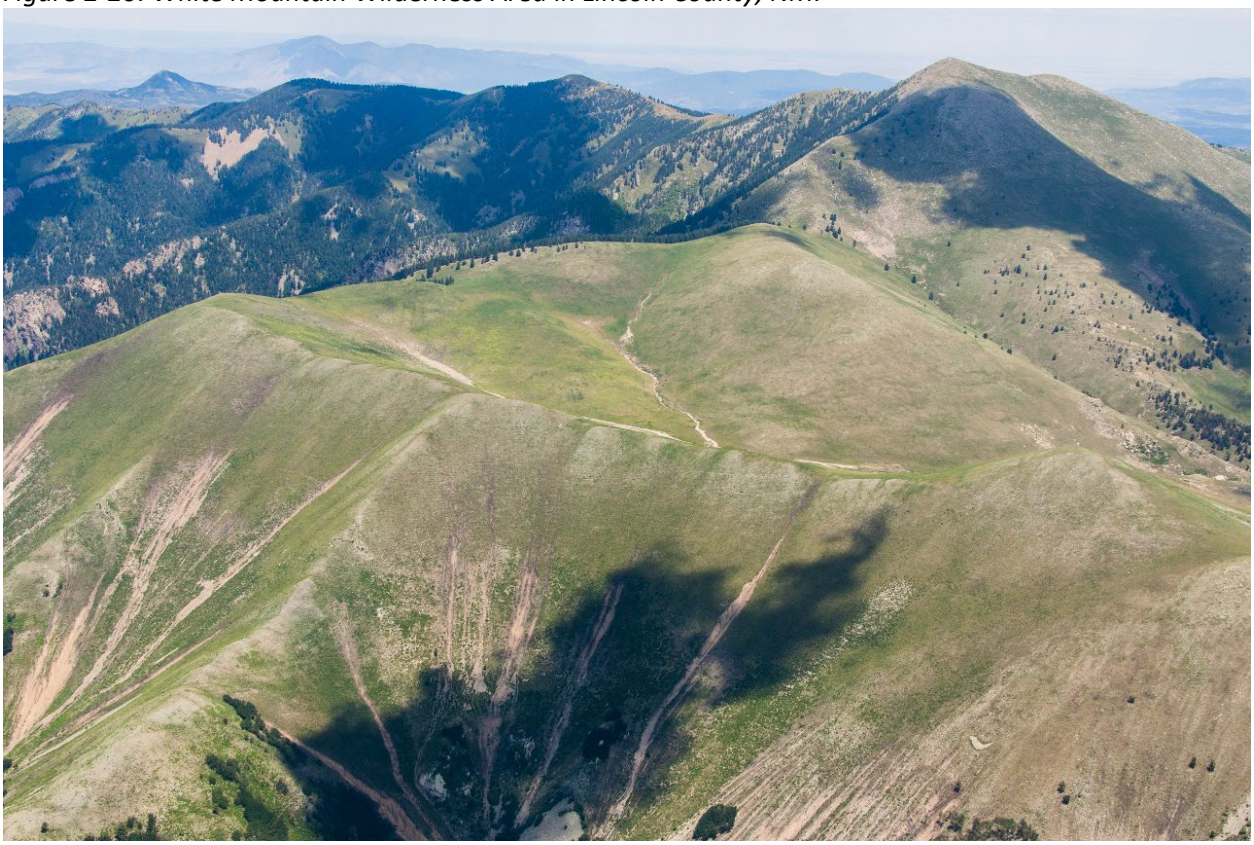
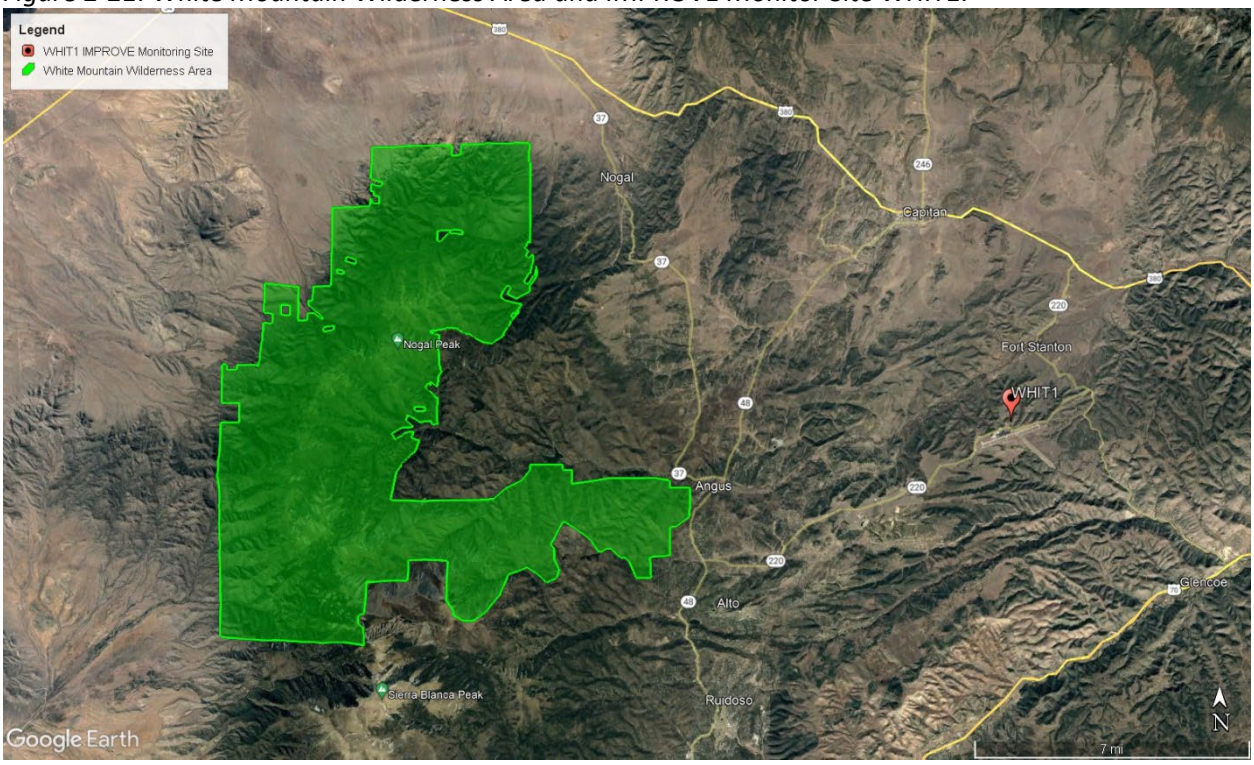


Photo credit: Dan Ryerson, USFS.

The IMPROVE monitor site for White Mountain Wilderness Area is WHIT1, located on a low ridge between the Rio Bonito and Little Creek, near the Sierra Blanca regional airport about nine miles east of the Wilderness, at an elevation of 6,770 feet. WHIT1 is on a well-exposed low ridge at an elevation near lower Wilderness elevations, where downslope flow conditions bring Wilderness air towards the monitor via the Rio Bonito and Little Creek drainages. As a result, WHIT1 is considered representative of visibility conditions in Wilderness locations.

Figure 2-21: White Mountain Wilderness Area and IMPROVE Monitor Site WHIT1.



Chapter 3: Ambient Monitor Data Analysis

This chapter provides an introduction to visibility-related concepts and a detailed look at the data, trends and contributors to light extinction at all New Mexico Class I Areas. Baseline, first period midpoint, first period end point, and current visibility conditions for the most impaired and clearest days are quantified to track visibility improvements over time and show progress to date and progress during the period covered by the embedded progress report in Chapter 5 of this Regional Haze SIPr Rd 2 (2019-2028). Natural visibility conditions for the most impaired and clearest days are also quantified to show the amount by which current visibility conditions exceed natural conditions.

This chapter also provides Regional Haze Rule requirements for ambient monitor data. Unless otherwise noted, all monitor data presented in this chapter comes from the Western Regional Air Partnership (WRAP) Technical Support System (TSS) website. Important definitions and concepts related to visibility can be found in this Regional Haze SIPr Rd 2 (2019 – 2028) (see Section 1.1: Definitions of Visibility-Related Concepts) and on the WRAP TSS website. [56]

3.1 Regulatory Requirements

The Regional Haze Rule requires that this Regional Haze SIPr Rd 2 (2019-2028) contain the following information about each New Mexico Class I Area:

1) The baseline visibility conditions at the site. [57] Baseline visibility conditions are the average of the five annual values for the 20% most impaired days of the year and 20% clearest days of the year during the period from 2000 to 2004. [58,]
2) The natural visibility conditions at the site. Natural visibility conditions are visibility that would exist at a Class I Area when only natural causes of visibility impairment, not anthropogenic causes, are present, on either the 20% most impaired days of the year or 20% clearest days of the year, as estimated by appropriate data analysis techniques. [59]
3) The current visibility conditions at the site. Current visibility conditions are the average of the five annual values for the 20% most impaired days of the year and 20% clearest days of the year during the most recent five-year period for which data are available. [60]
4) Progress to date for most impaired and clearest days. This information consists of the progress made toward natural visibility conditions since the baseline period, including during the

[56] https://views.cira.colostate.edu/tssv2/Pub/Glossary.aspx.

[57] The deciview (dv) or "haze index" is the unit of measurement of haze. It is a measure of visibility derived from light extinction that is designed so that incremental changes in the index correspond to uniform incremental changes in visual perception, across the entire range of conditions from pristine to highly impaired. The index (in units of dv) is calculated directly from the total light extinction (b_{ext} expressed in inverse megameters (Mm^{-1})) as follows: deciviews = 10 ln (b_{ext}/10). The index will be less than 0 for b_{ext} values below 10. All visibility conditions discussed here and elsewhere in this Regional Haze SIPr Rd 2 (2019 – 2028) are expressed in deciviews unless otherwise noted.

[58] 40 CFR §§ 51.301, 51.308(f)(1)(i).

[59] 40 CFR §§ 51.301, 51.308(f)(1)(ii). The provisions of the Regional Haze Rule cited do not specify a time period over which individual daily values must be averaged. The provisions also allow a choice of whether such averaging will occur on the Most Impaired Days "or" the Clearest Days. Based on EPA guidance, WRAP has developed an approach to this feature of the rule, which is discussed in the course of this chapter.

[60] 40 CFR §§ 51.301, 51.308(f)(1)(iii).

previous planning period, for the 20% most impaired days of the year and 20% clearest days of the year. [61]

5) The difference between current visibility conditions and natural visibility conditions for the most impaired days and clearest days. [62]

In addition to the above requirements, the U.S. Environmental Protection Agency's (EPA) August 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period indicates that a Regional Haze State Implementation Plan (SIP) may, but is not required to, include an extinction budget for each Class I Area. [63] An extinction budget shows the measured or estimated light extinction contribution from each ambient particulate matter (PM) species at a Class I Area and the extent to which each is responsible for that visibility interference.

This chapter presents the above-described regulatory information for each of New Mexico's Class I Areas. This information includes the mandatory information regarding visibility conditions described in items 1) through 5), above, as well as optional information related to extinction budgets. Additional information regarding visibility conditions and changes for the embedded progress report in Chapter 5 of this Regional Haze SIPr Rd 2 (2019-2028) is also presented in this chapter and discussed in Section 5.5.

3.2 Trends in Visibility Conditions

This section presents information to satisfy the requirements of 40 CFR § 51.308(f)(1)(i) through (v) and 40 CFR § 51.308(g)(3). These provisions require this Regional Haze SIPr Rd 2 (2019-2028) to present monitor data on visibility conditions for each New Mexico Class I Area to demonstrate progress toward natural visibility conditions. The information presented is as follows.

- Baseline, first period midpoint, first period end point, current, and natural visibility conditions on the 20% most impaired days and 20% clearest days. [64]
- Progress to date for the most impaired and clearest days, represented by the change from baseline to current visibility conditions.
- The difference between current and natural visibility conditions for the most impaired and clearest days.
- The difference between baseline and first period end point visibility conditions for the most impaired and clearest days.
- Progress during the period covered by the embedded progress report in Chapter 5 of this Regional Haze SIPr Rd 2 (2019-2028) for the most impaired and clearest days, represented by the change from first period midpoint to first period end point visibility conditions.

Table 3-1 lists the types of aerosol species measured by the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitor sites in New Mexico and elsewhere. The table also presents the mechanism by which they form in the atmosphere and provides examples of the key sources of each aerosol species. Some of these sources are the result of human activities like industry or transportation,

[61] 40 CFR § 51.308(f)(1)(iv).
[62] 40 CFR § 51.308(f)(1)(v).
[63] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019 ("EPA Regional Haze SIP Guidance"), p. D-2.
[64] NM used the period from 2008 to 2012 to represent first period midpoint conditions, the period from 2014 to 2018 to represent first period end point conditions, and the period from 2019 to 2023 (the most recent five-year period for which data are available) to represent current conditions.

while others occur naturally. Each species listed in the table is part of a broader class of pollutant tracked by EPA for multiple regulatory purposes: particulate matter less than or equal to 2.5 microns in diameter ($PM_{2.5}$). For comparison, a human hair is about 50 to 70 microns in diameter. EPA provides additional background information about particulate matter at https://www.epa.gov/pm-pollution/particulate-matter-pm-basics.

Table 3-1: Aerosol Species Measured by IMPROVE Monitors.

Aerosol species	Alternate names for aerosol	Formation mechanism	Examples of key sources
Fine soil	Soil dust, fine mode mineral dust, windblown dust	Wind effects on earth's surface (global scale)	Long-range transport from global desert areas; dust from construction sites or unpaved road traffic; land areas disturbed from human or natural events
Coarse mass	Coarse particulate matter, mineral dust, CM	Wind effects on earth's surface (local to regional)	Windblown dust from arid regions; dust from construction sites or unpaved road traffic; land areas disturbed from human or natural events
Elemental carbon	Light absorbing carbon, EC	Combustion of carbon containing fuels	Fossil fuel combustion sources; on and off-road mobile engine sources, e.g. cars, trucks, construction equipment; biofuel and biomass (wildfires) burning
Organic mass	Organic carbon, particulate organic mass, particulate organic matter, OC, POM	Combustion of carbon containing fuels, biological processes	Fossil fuel-fired electrical generators; internal combustion engines; biogenic sources (forested areas); biofuel and biomass (wildfires) burning
Ammonium nitrate	NH_4NO_3	Conversion of nitrogen oxide emissions from combustion processes	Coal and natural gas-fired electric power plants; large industrial facilities like Portland cement plants; on and off-road mobile sources, e.g. cars, trucks, construction equipment; small industrial equipment like engines used for oil and gas production
Ammonium sulfate	$(NH_4)_2SO_4$	Conversion of sulfur dioxide emissions from combustion processes	Coal-fired electric power plants; other fuel combustion sources; large industrial facilities such as pulp and papermills, smelters, refineries and Portland cement plants; on and off-road mobile sources, e.g. cars, trucks, construction equipment.
Sea salt		Wind effects on earth's surface (local to global)	Wind over ocean surface, dry lake beds or playas; generally negligible at New Mexico Class I Areas.

Additional information on the above species and related scientific and technical information may be found at https://www.epa.gov/visibility.

Table 3-2 and Table 3-3 present the monitor data on visibility conditions discussed above. As these tables show, current visibility conditions are better than baseline conditions at all New Mexico Class I Areas on both the most impaired and clearest days, demonstrating progress toward natural visibility conditions since the baseline period in all areas. They also show that visibility conditions were better at the end point of the first period than at the midpoint on both the most impaired and clearest days, demonstrating progress toward natural visibility conditions during the period covered by the embedded progress report in Chapter 5 of this Regional Haze SIPr Rd 2 (2019-2028).

*Table 3-2: Visibility Conditions in New Mexico Class I Areas, 20% Most Impaired Days (in dv).**

Class 1 Area	IMPROVE Monitor Site	Baseline Visibility Conditions (2000-2004 avg)	First Period Midpoint Visibility Conditions (2008-2012 avg)	First Period End Point Visibility Conditions (2014-2018 avg)	Current Visibility Conditions (2019-2023 avg)	Natural Visibility Conditions	Change from Baseline to Current Conditions	Difference Between Current and Natural Conditions	Difference Between Baseline and First Period End Point Conditions	Change from First Period Midpoint to First Period End Point Conditions
Bandelier Wilderness	BAND1	9.7	9.3	8.4	8.0	4.6	-1.7	3.4	-1.3	-0.9
Bosque del Apache Wilderness	BOAP1	11.6	11.2	10.5	10.1	5.4	-1.5	4.7	-1.1	-0.7
Carlsbad Caverns National Park	GUMO1	14.6	12.9	12.6	12.5	4.8	-2.1	7.7	-2.0	-0.3
Gila Wilderness	GICL1	9.0	8.3	7.6	7.5	4.2	-1.5	3.3	-1.4	-0.7
Pecos Wilderness	WHPE1	7.3	6.7	6.0	5.7	3.5	-1.6	2.2	-1.3	-0.7
Salt Creek Wilderness	SACR1	16.5	15.3	15.0	14.3	5.5	-2.2	8.8	-1.5	-0.3
San Pedro Parks Wilderness	SAPE1	7.7	7.0	6.4	6.0	3.3	-1.7	2.7	-1.3	-0.6
Wheeler Peak Wilderness	WHPE1	7.3	6.7	6.0	5.7	3.5	-1.6	2.2	-1.3	-0.7
White Mountain Wilderness	WHIT1	11.3	10.5	10.0	9.7	4.9	-1.6	4.8	-1.3	-0.5

*The data in this table addresses the requirements of 40 CFR § 51.308(f)(1)(i) through (f)(1)(v) and 40 CFR § 51.308(g)(3). Source: WRAP TSS, TemplateTable - Product #XATP_VTTB_PTPP, except 2019-2023 data which were obtained from the preliminary TSS v3 website (https://views.cira.colostate.edu/tssv3/).

*Table 3-3: Visibility Conditions in New Mexico Class I Areas, 20% Clearest Days (in dv).**

Class 1 Area	IMPROVE Monitor Site	Baseline Visibility Conditions (2000-2004 avg)	First Period Midpoint Visibility Conditions (2008-2012 avg)	First Period End Point Visibility Conditions (2014-2018 avg)	Current Visibility Conditions (2019-2023 avg)	Natural Visibility Conditions	Change from Baseline to Current Conditions	Difference Between Current and Natural Conditions	Difference Between Baseline and First Period End Point Conditions	Change from First Period Midpoint to First Period End Point Conditions
Bandelier Wilderness	BAND1	5.0	3.9	3.0	2.9	1.3	-2.1	1.6	-2.0	-0.9
Bosque del Apache Wilderness	BOAP1	6.3	5.6	4.6	4.5	2.2	-1.8	2.3	-1.7	-1.0
Carlsbad Caverns National Park	GUMO1	5.9	5.2	4.7	4.7	1.0	-1.2	3.7	-1.2	-0.5
Gila Wilderness	GICL1	3.3	2.5	2.1	2.2	0.5	-1.1	1.7	-1.2	-0.4
Pecos Wilderness	WHPE1	1.2	0.6	0.3	0.2	-0.6	-1.0	0.8	-0.9	-0.3
Salt Creek Wilderness	SACR1	7.8	7.2	6.6	6.7	2.1	-1.1	4.6	-1.2	-0.6
San Pedro Parks Wilderness	SAPE1	1.5	1.1	0.4	0.2	-0.7	-1.3	0.9	-1.1	-0.7
Wheeler Peak Wilderness	WHPE1	1.2	0.6	0.3	0.2	-0.6	-1.0	0.8	-0.9	-0.3
White Mountain Wilderness	WHIT1	3.6	3.3	2.5	2.7	0.7	-0.9	2.0	-1.1	-0.8

*The data in this table addresses the requirements of 40 CFR § 51.308(f)(1)(i) through (f)(1)(v) and 40 CFR § 51.308(g)(3). Source: WRAP TSS, TemplateTable - Product #XATP_VTTB_PTPP, except 2019-2023 data which were obtained from the preliminary TSS v3 website (https://views.cira.colostate.edu/tssv3/).

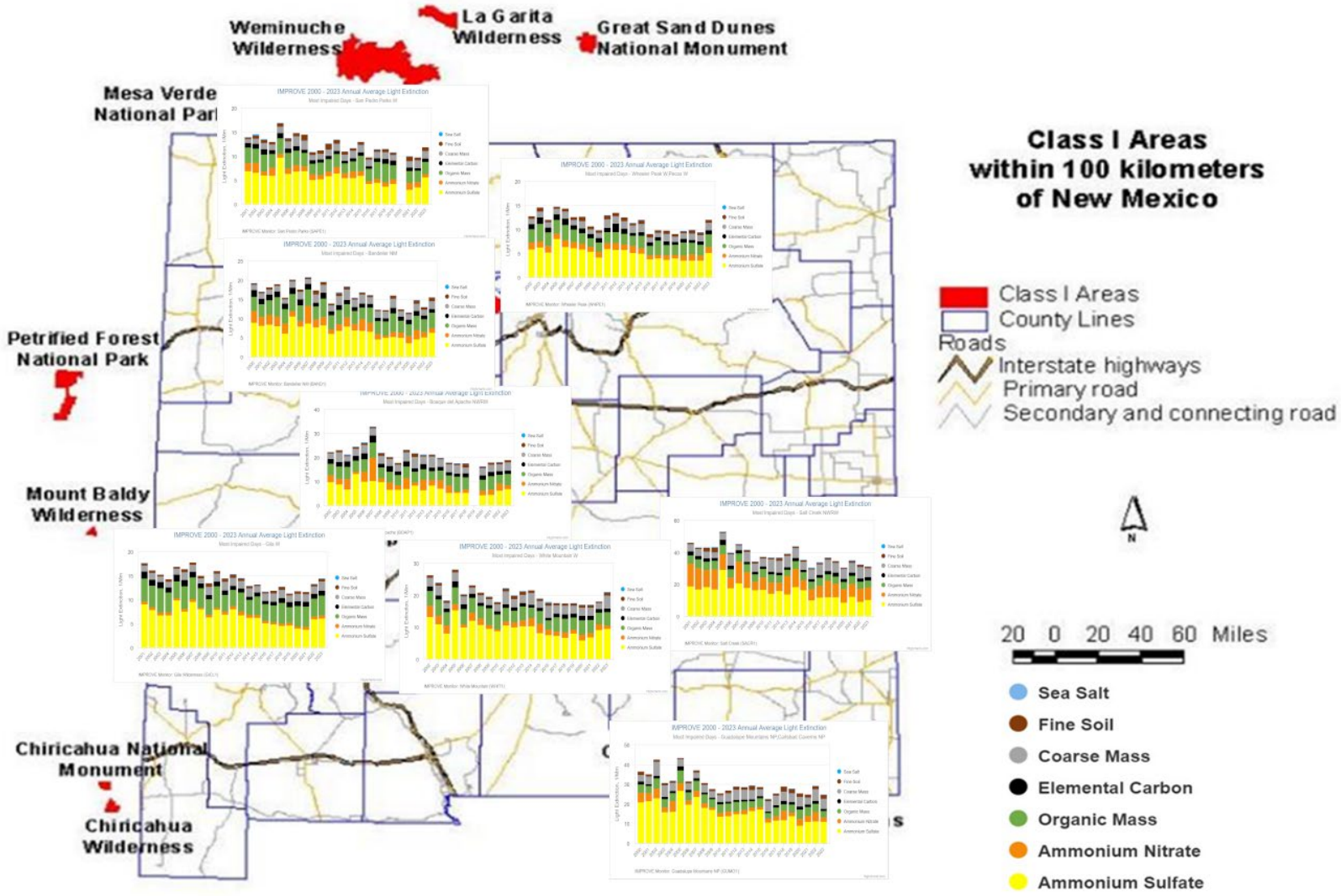
3.3 New Mexico IMPROVE Network Light Extinction Trends Analysis

Figure 3-1 provides an overview of the annual changes in the extinction magnitude and aerosol species contributors on the most impaired days at all New Mexico IMPROVE monitor sites over the 2000-2023 monitoring period. All sites have shown visibility improvement over the monitoring period, as indicated by the downward slope of the uppermost boundary of the bars. The graphs super-imposed over the map are meant to provide only a quick visual reference, not a full-sized rendition of each graph with complete notation. Full versions of the bar graphs in this map, and other detailed visualizations of monitor trends, are available on the WRAP TSS.

Figure 3-2 through Figure 3-9 show deciview trends and the aerosol species contributing to light extinction at each New Mexico IMPROVE monitor site during the five-year periods representing baseline, first period midpoint, first period end point, and current visibility conditions on the most impaired days and the clearest days, as well as the contributing species under natural conditions. The stacked bar charts give speciated contributions, which sum to the total particle light extinction coefficient. Note that the contributions to light extinction by each species are measured in inverse megameters. The total visibility conditions in deciviews appear above each bar for each five-year period represented. Contributions to light extinction from individual species are color-coded and presented in the following order: sea salt (light blue), fine soil (maroon), coarse mass (gray), organic mass from carbon (green), elemental carbon (black), ammonium nitrate (orange), and ammonium sulfate (yellow). Note that the dv value includes the Rayleigh Scattering contribution at each site. [65]

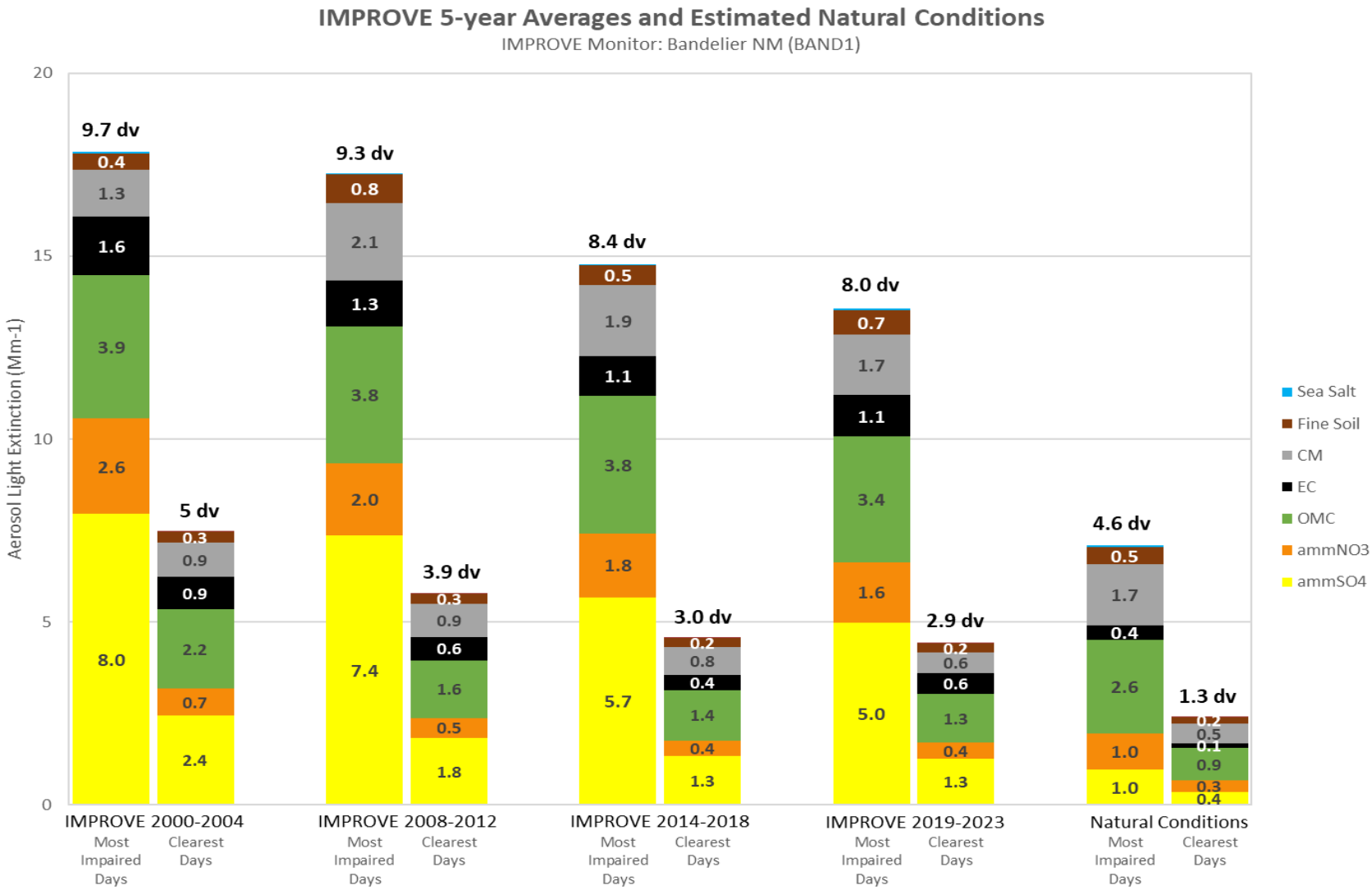
[65] Rayleigh Scattering is defined in 1.1.2: Other Definitions.

Figure 3-1: Map Overview of New Mexico and Adjacent Class I Areas and Progression of Speciated Visibility Impairment on the Most Impaired Days over the 2000-2023 Monitoring Period. Wheeler Peak Wilderness and Pecos Wilderness share a single monitor (WHPE1) as do Carlsbad Caverns NP and Guadalupe Mountains NP (GUMO1).



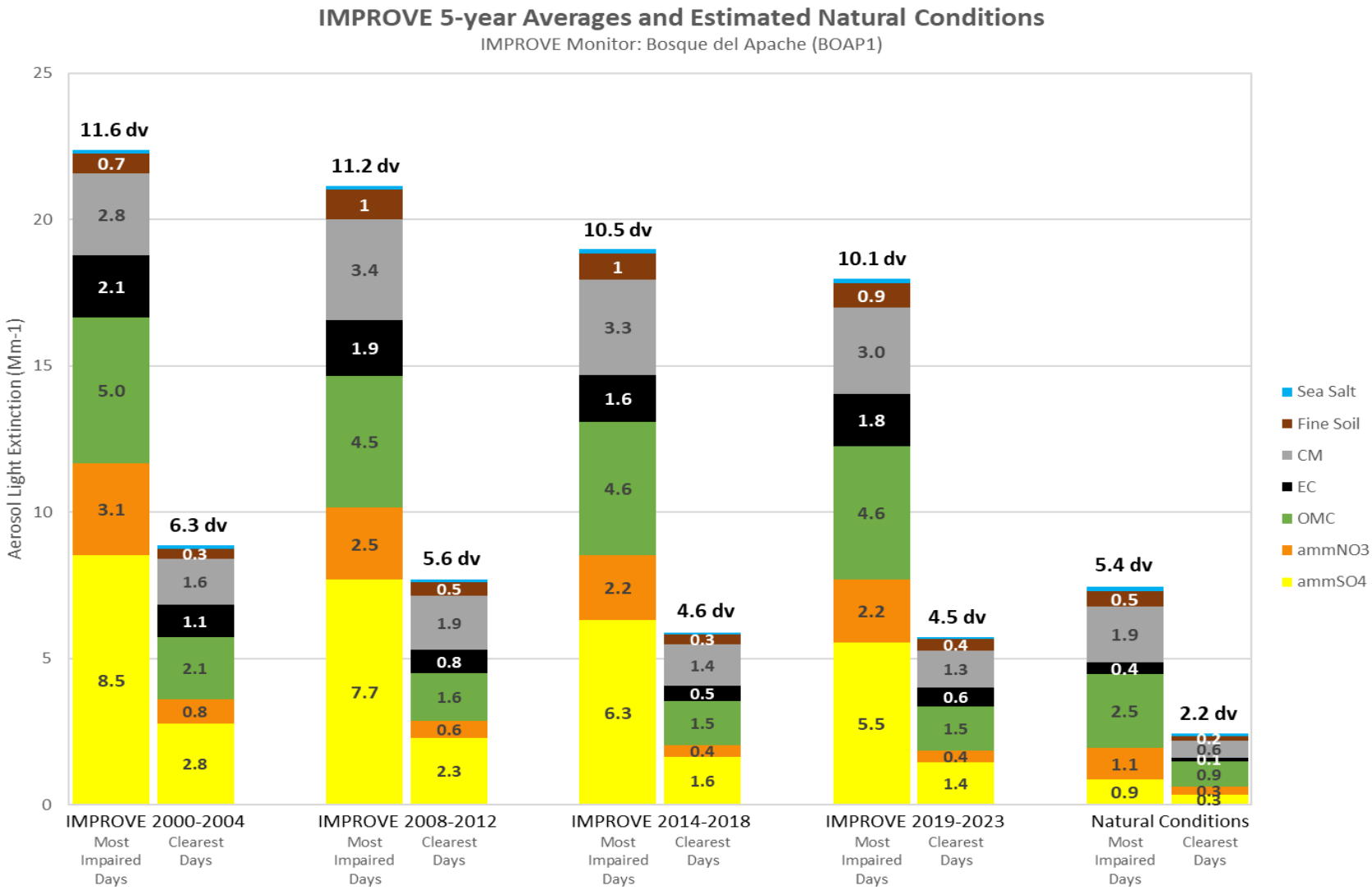
3.3.1 Bandelier Wilderness Area

Figure 3-2: Contributors to Light Extinction, Most Impaired and Clearest Days, Bandelier Wilderness Area.



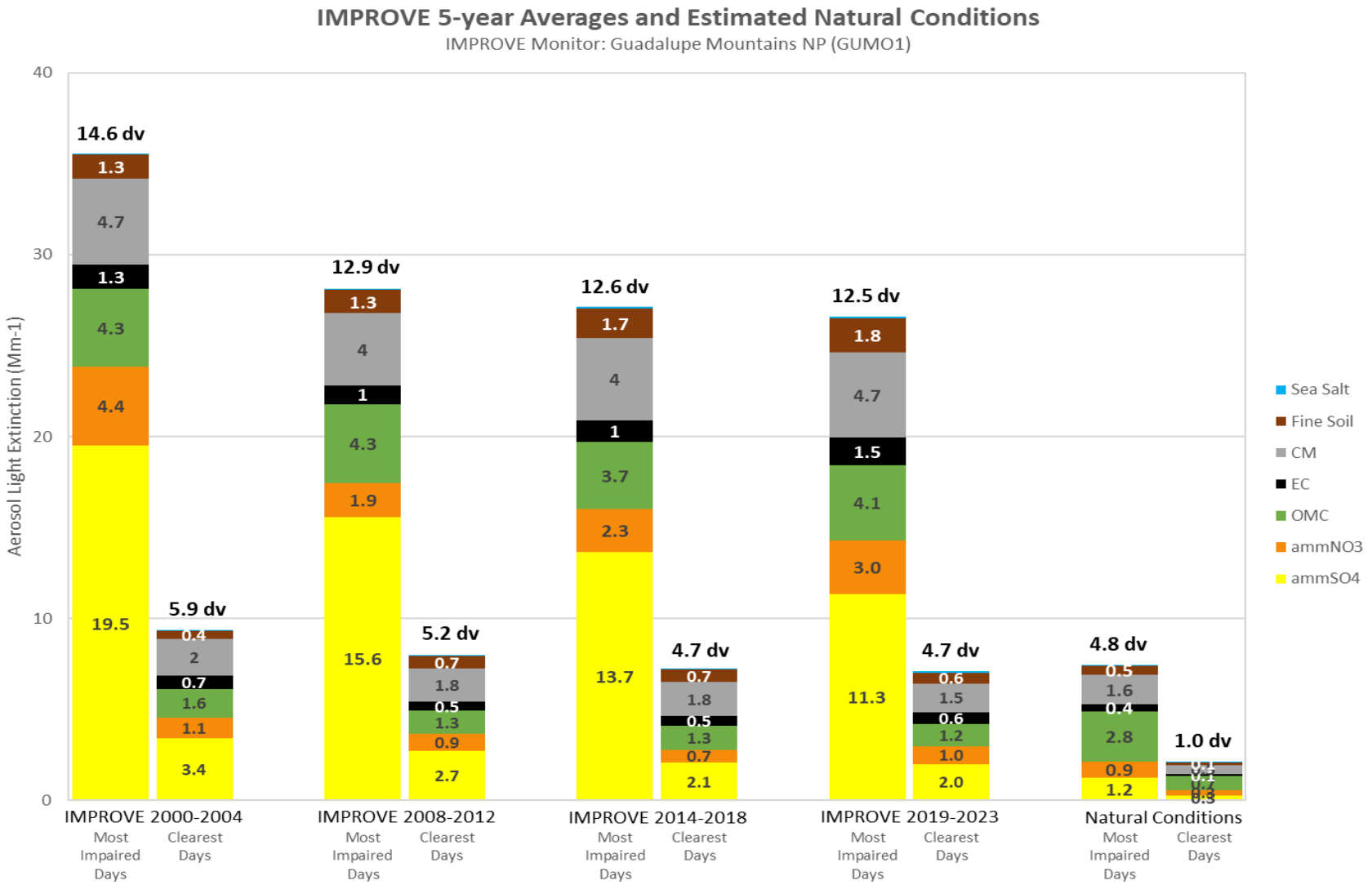
3.3.2 Bosque del Apache Wilderness Area

Figure 3-3: Contributors to Light Extinction, Most Impaired and Clearest Days, Bosque del Apache Wilderness Area.



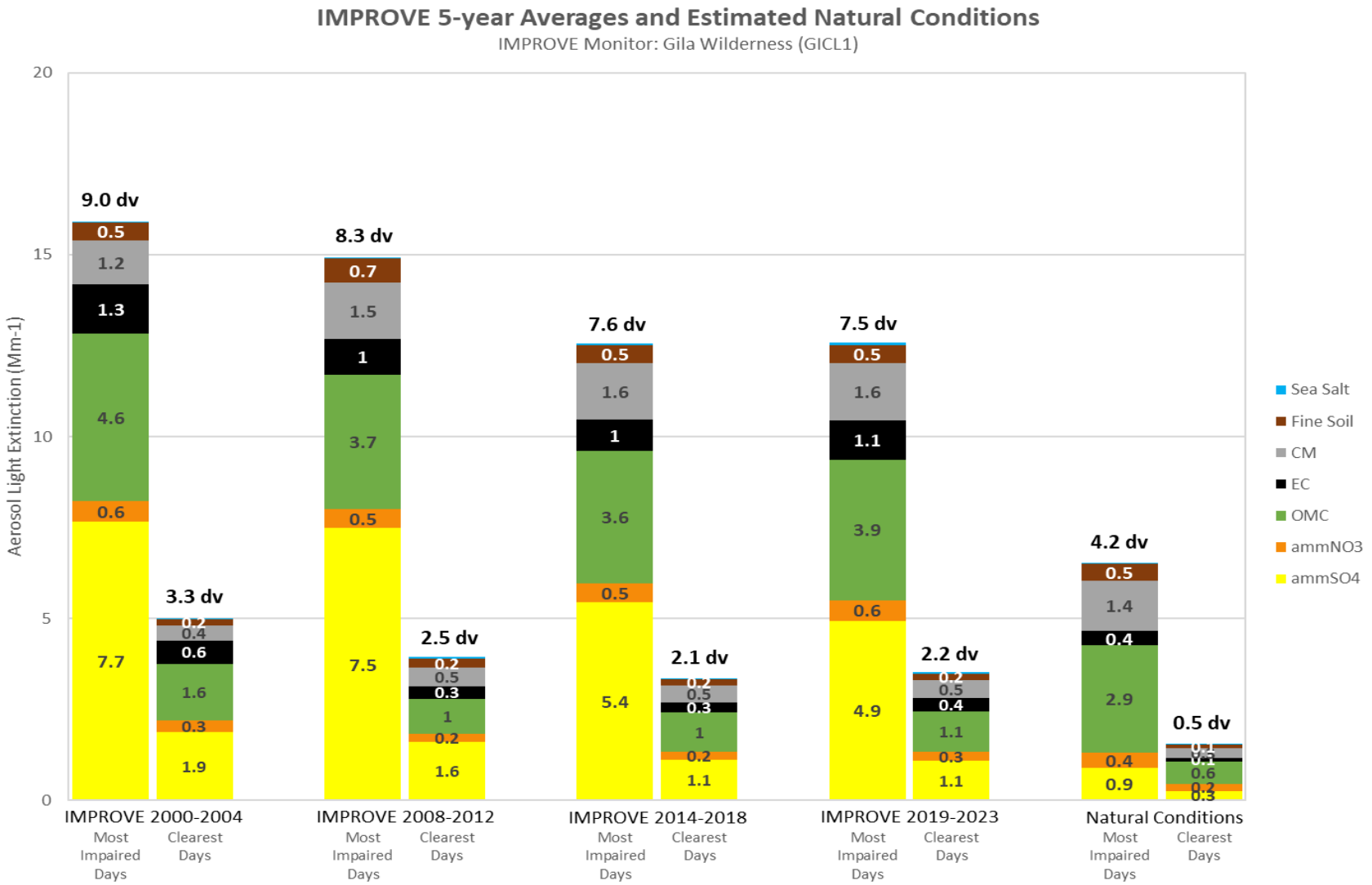
3.3.3 Carlsbad Caverns National Park

Figure 3-4: Contributors to Light Extinction, Most Impaired and Clearest Days, Carlsbad Caverns National Park.



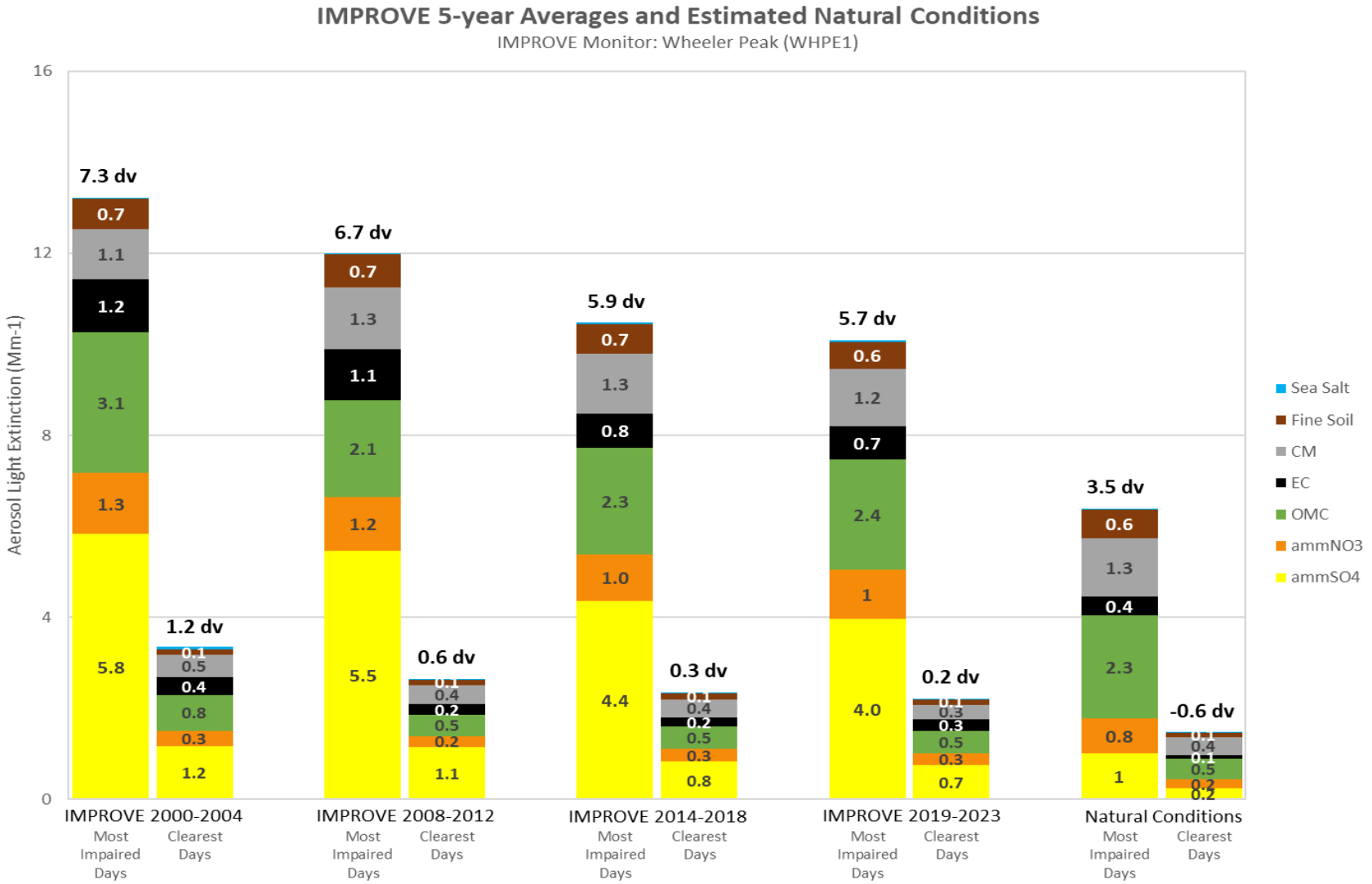
3.3.4 Gila Wilderness Area

Figure 3-5: Contributors to Light Extinction, Most Impaired and Clearest Days, Gila Wilderness Area.



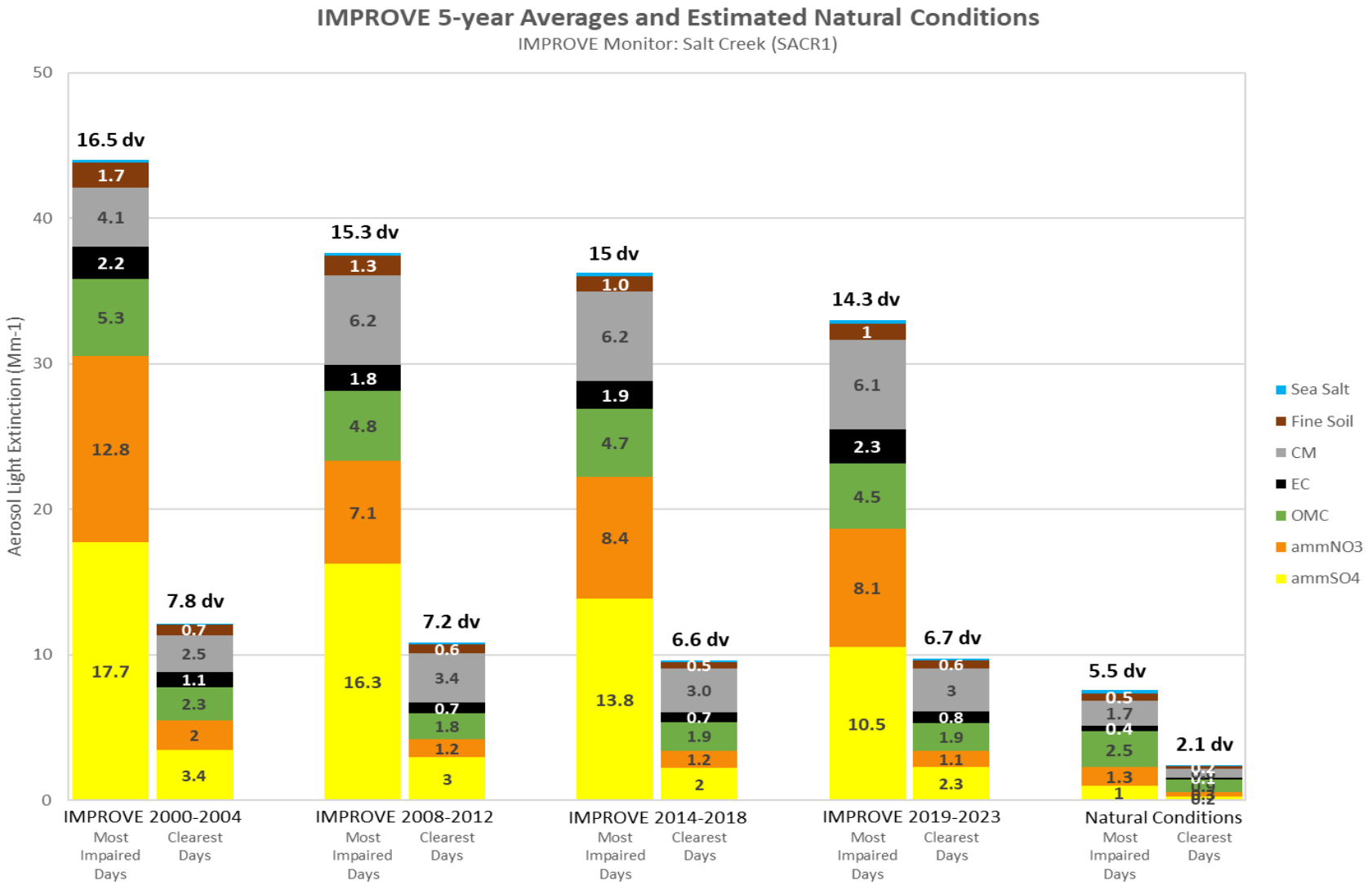
3.3.5 Pecos Wilderness Area and Wheeler Peak Wilderness Area

Figure 3-6: Contributors to Light Extinction, Most Impaired and Clearest Days, Pecos Wilderness Area and Wheeler Peak Wilderness Area.



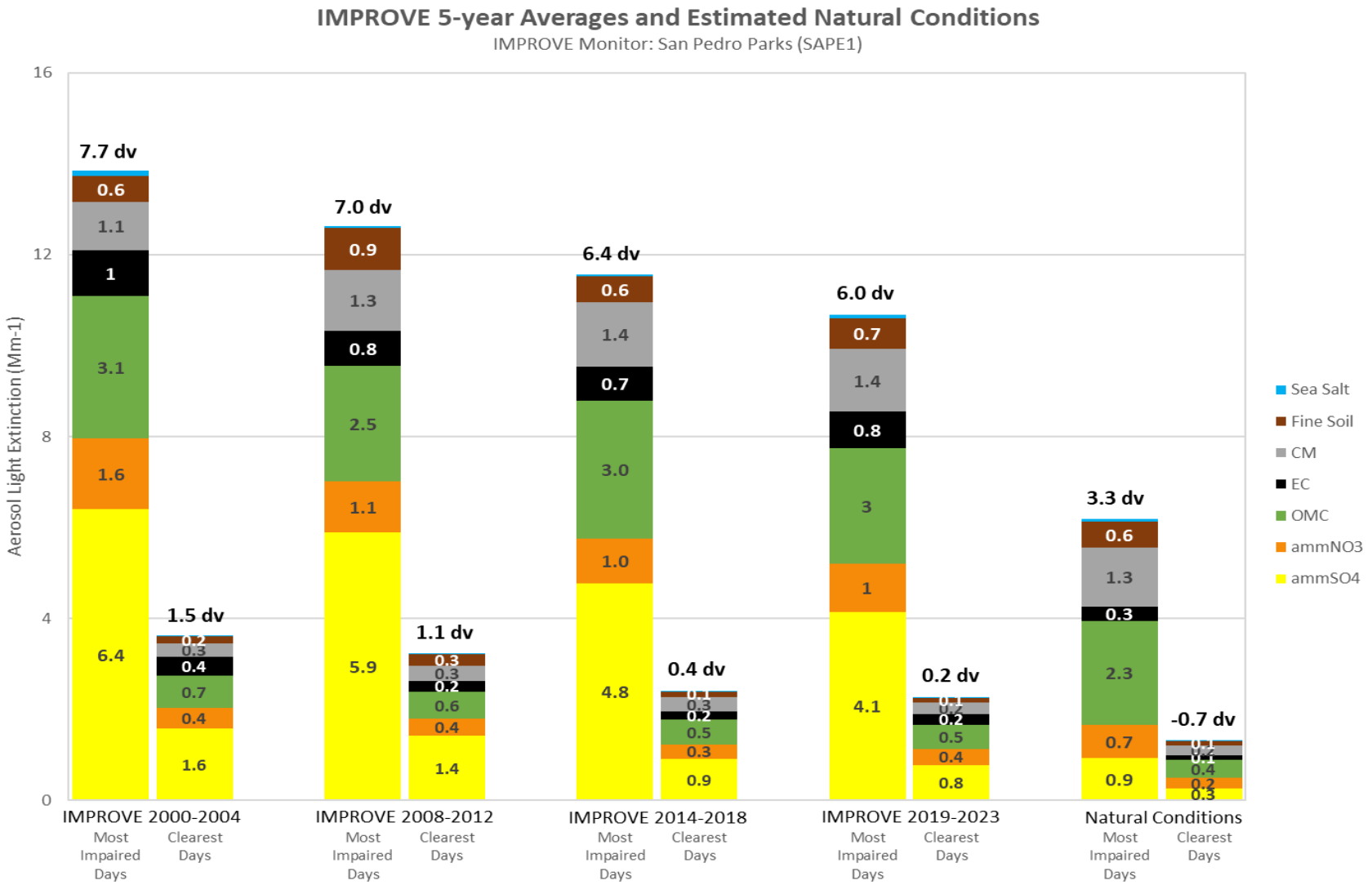
3.3.6 Salt Creek Wilderness Area

Figure 3-7: Contributors to Light Extinction, Most Impaired and Clearest Days, Salt Creek Wilderness Area.



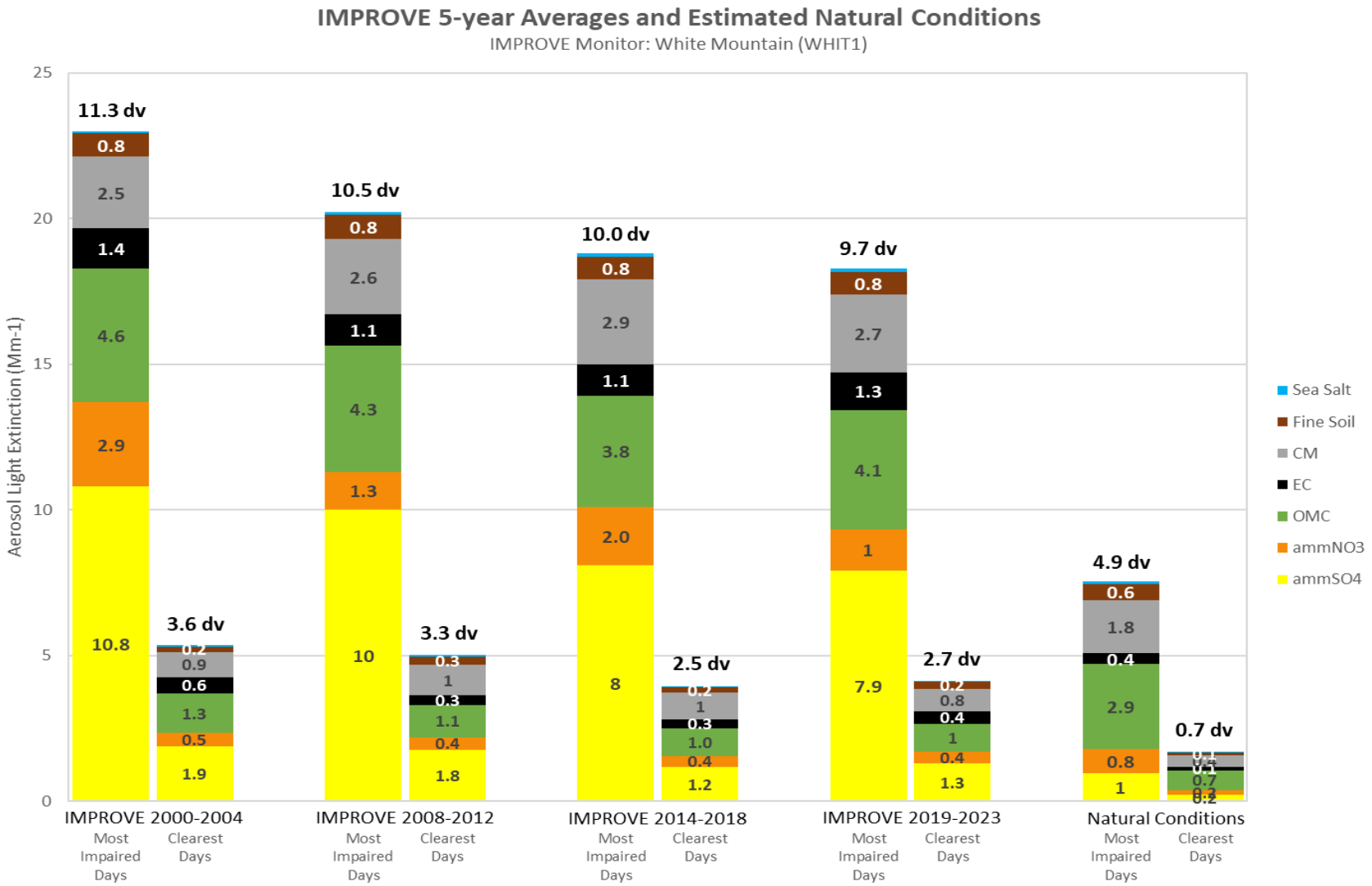
3.3.7 San Pedro Parks Wilderness Area

Figure 3-8: Contributors to Light Extinction, Most Impaired and Clearest Days, San Pedro Parks Wilderness Area.



3.3.8 White Mountain Wilderness Area

Figure 3-9: Contributors to Light Extinction, Most Impaired and Clearest Days, White Mountain Wilderness Area.



3.4 Monitoring Data Summary

Figure 3-2 through Figure 3-9 show deciview trends and the aerosol species contributing to light extinction during the five-year periods representing baseline, first period midpoint, first period end point, and current visibility conditions, as well as the contributing species under natural conditions, at New Mexico Class I Areas. All network sites show improving visibility and progress toward the Regional Haze Rule goals of reducing impacts on the most impaired days while not backtracking during the clearest days.

Noteworthy trends across the network during the current period (2019-2023) include:

1) Ammonium sulfate was the primary driver of light extinction at all New Mexico Class I Areas on the most impaired days. On the clearest days, all sites were dominated by ammonium sulfate except for Gila Wilderness, Bosque del Apache Wilderness and Bandelier Wilderness, where organic mass made an equal or slightly larger contribution to light extinction, and Salt Creek Wilderness, where coarse mass made the largest contribution.
2) Though the order changed from site to site, the top three contributors to light extinction at New Mexico Class I Areas were ammonium sulfate, organic mass, and coarse mass on both the most impaired days and the clearest days. The only exceptions to this were Salt Creek Wilderness on the most impaired days and San Pedro Parks Wilderness on the clearest days, when ammonium nitrate was one of the top three contributors instead of either organic mass or coarse mass.
3) The combined ammonium sulfate and ammonium nitrate contribution to light extinction makes up approximately half of the total contribution at all sites through to the current period (2019-2023) on both the most impaired days and the clearest days. Sulfur dioxide (SO_2) and nitrogen oxides (NO_X), are precursors to ammonium sulfate and ammonium nitrate.
4) The largest haze reductions over time (i.e., the largest reduction in individual species' contributions to light extinction) are generally associated with ammonium sulfate and ammonium nitrate, which have likely occurred due to reduced SO_2 and NO_X emissions since EPA first promulgated the Regional Haze Rule in 1999.

3.5 Tracking Visibility Progress Regulatory Requirements

The Regional Haze Rule requires calculation of a Uniform Rate of Progress (URP) for each Class I Area in the state.[66] To calculate the URP, the state must compare baseline visibility conditions for the most impaired days to natural visibility conditions for the most impaired days in the Class I Area and determine the uniform rate of visibility improvement (measured in deciviews of improvement per year) that would need to be maintained during each planning period in order to attain natural visibility conditions by the end of 2064.

As part of its Regional Haze SIP submission, a state is allowed to propose:

1) an adjustment to the URP for a Class I Area to account for impacts from anthropogenic sources outside the United States;[67] and
2) an adjustment to the URP for a Class I Area to account for impacts from wildland prescribed fires that were conducted with the objective to establish, restore, and/or maintain sustainable and resilient wildland ecosystems, to reduce the risk of catastrophic wildfires, and/or to preserve

[66] 40 CFR § 51.308(f)(1)(vi)(A).
[67] 40 CFR § 51.308(f)(1)(vi)(B).

endangered or threatened species during which appropriate basic smoke management practices were applied. [68]

The WRAP contractor, Ramboll, developed URP adjustments to account for both types of impacts for all Class I Areas in WRAP states. The methods Ramboll used to calculate these adjustments are discussed in Appendix B. [69] NMED is using both of these adjustments for all of New Mexico's Class I Areas. [70]

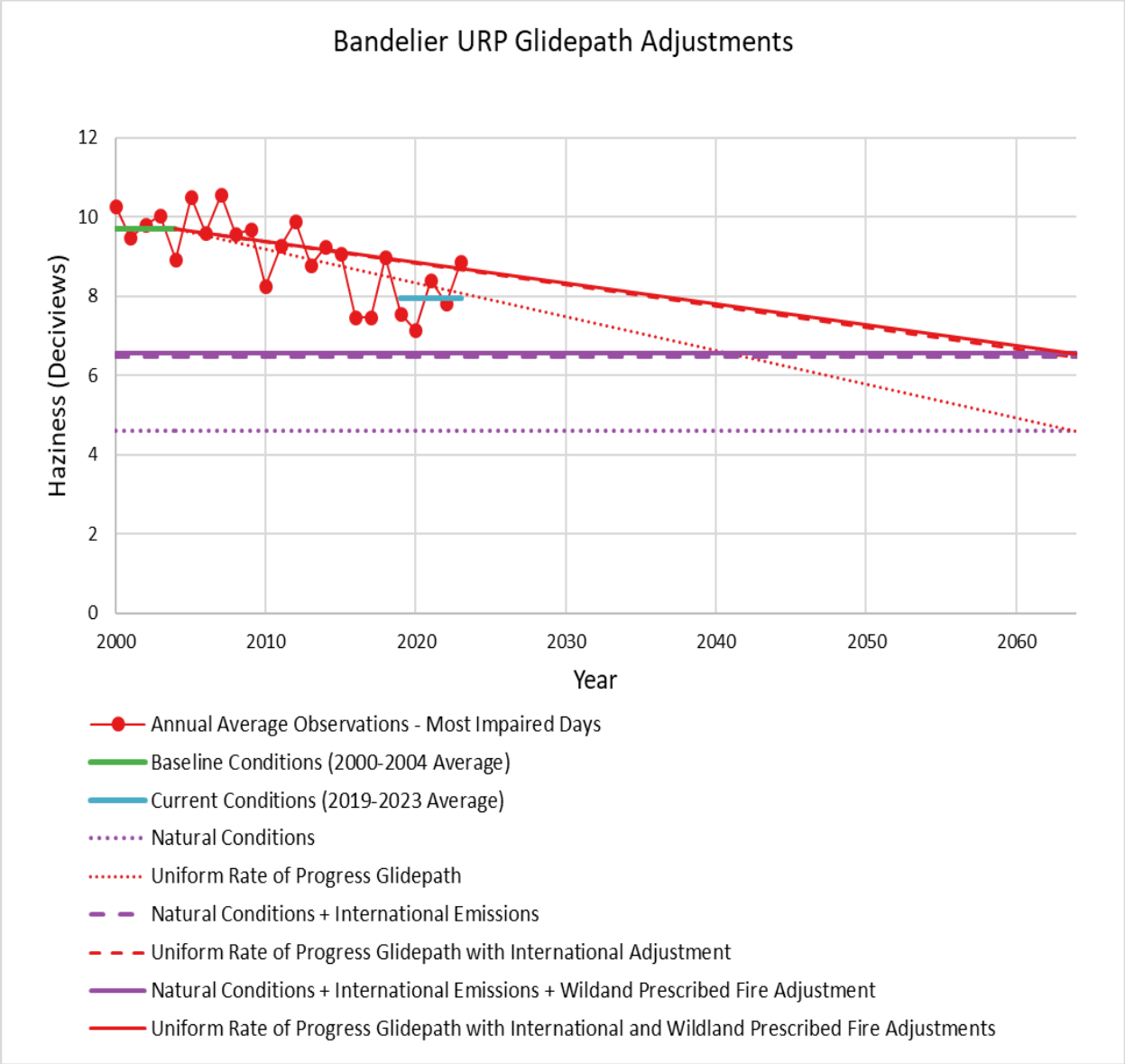
3.6 Uniform Rate of Progress for New Mexico Class I Areas

Figure 3-10 through Figure 3-17 show the adjusted Uniform Rate of Progress (URP) accounting for impacts from anthropogenic sources outside the U.S. and wildland prescribed fires for all New Mexico Class I Areas.

[68] *Id*.
[69] *See* Section 9.0, Adjustments to the Uniform Rate of Progress Glidepath.
[70] URP glidepath adjustments for New Mexico Class I Areas are available on the Modeling Data Analysis page of the WRAP TSS (https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx). *See* Product #5 under Visibility Progress and Projections.

3.6.1 Bandelier Wilderness Area Adjusted URP

Figure 3-10: BAND1 Adjusted URP.

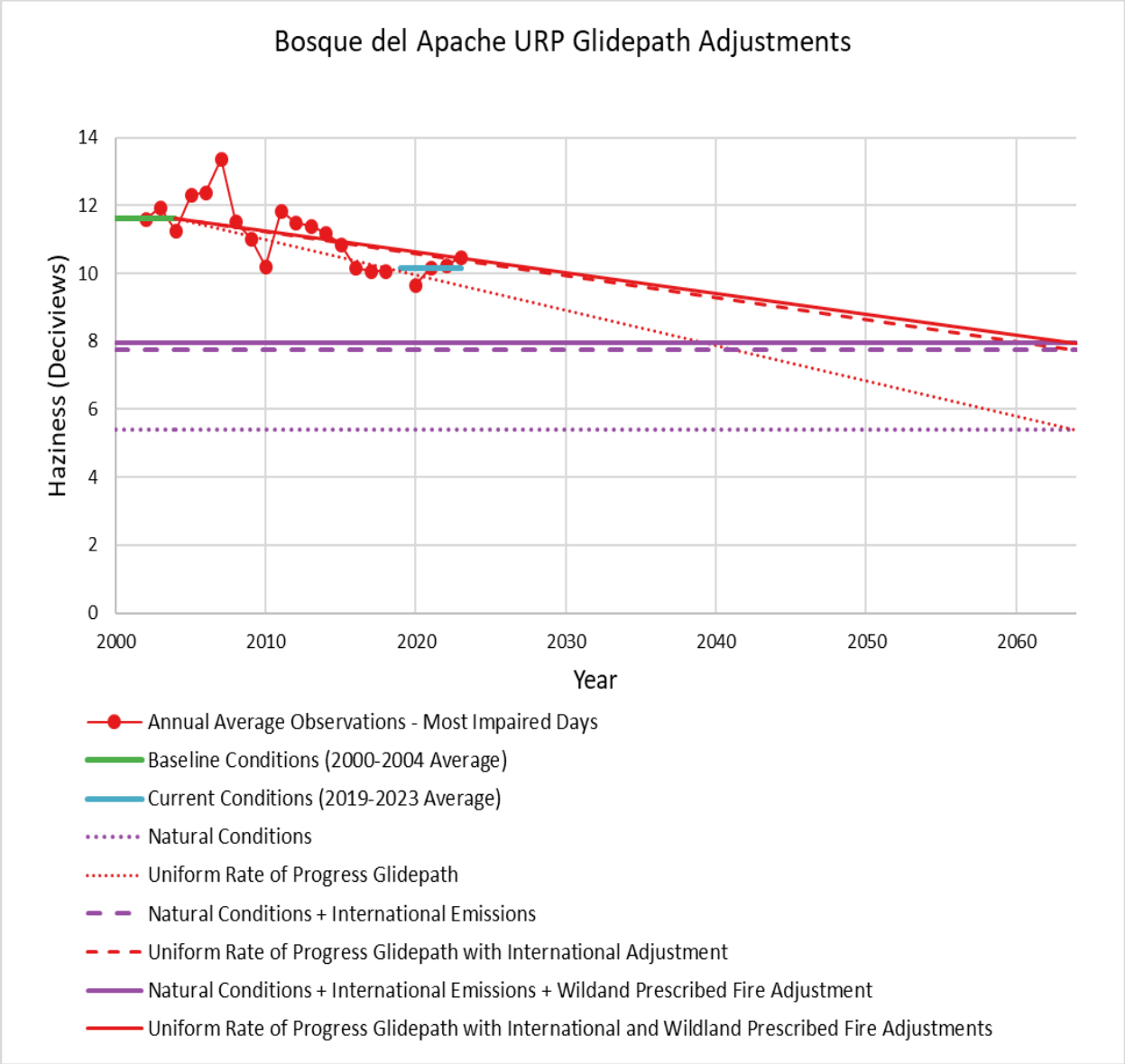


Values for BAND1:

	Deciviews
Baseline Conditions (2000-2004 Average)	9.7
Current Conditions (2019-2023 Average)	8.0
Natural Conditions	4.6
Natural Conditions + International Emissions	6.5
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	6.5

3.6.2 Bosque del Apache Wilderness Area Adjusted URP

Figure 3-11: BOAP1 Adjusted URP.

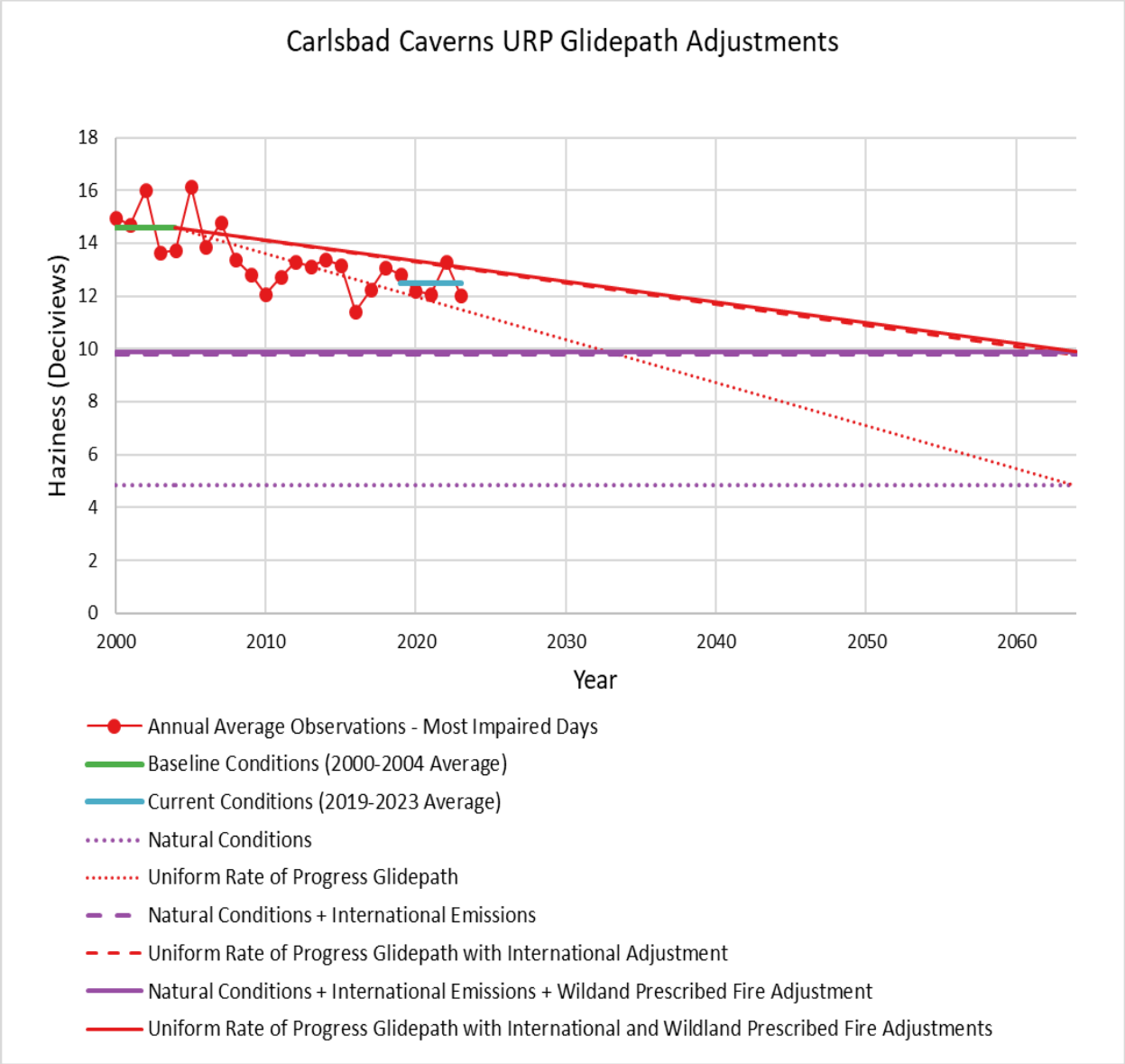


Values for BOAP1:

	Deciviews
Baseline Conditions (2000-2004 Average)	11.6
Current Conditions (2019-2023 Average)	10.1
Natural Conditions	5.4
Natural Conditions + International Emissions	7.7
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	8.0

3.6.3 Carlsbad Caverns National Park Adjusted URP

Figure 3-12: GUMO1 Adjusted URP.

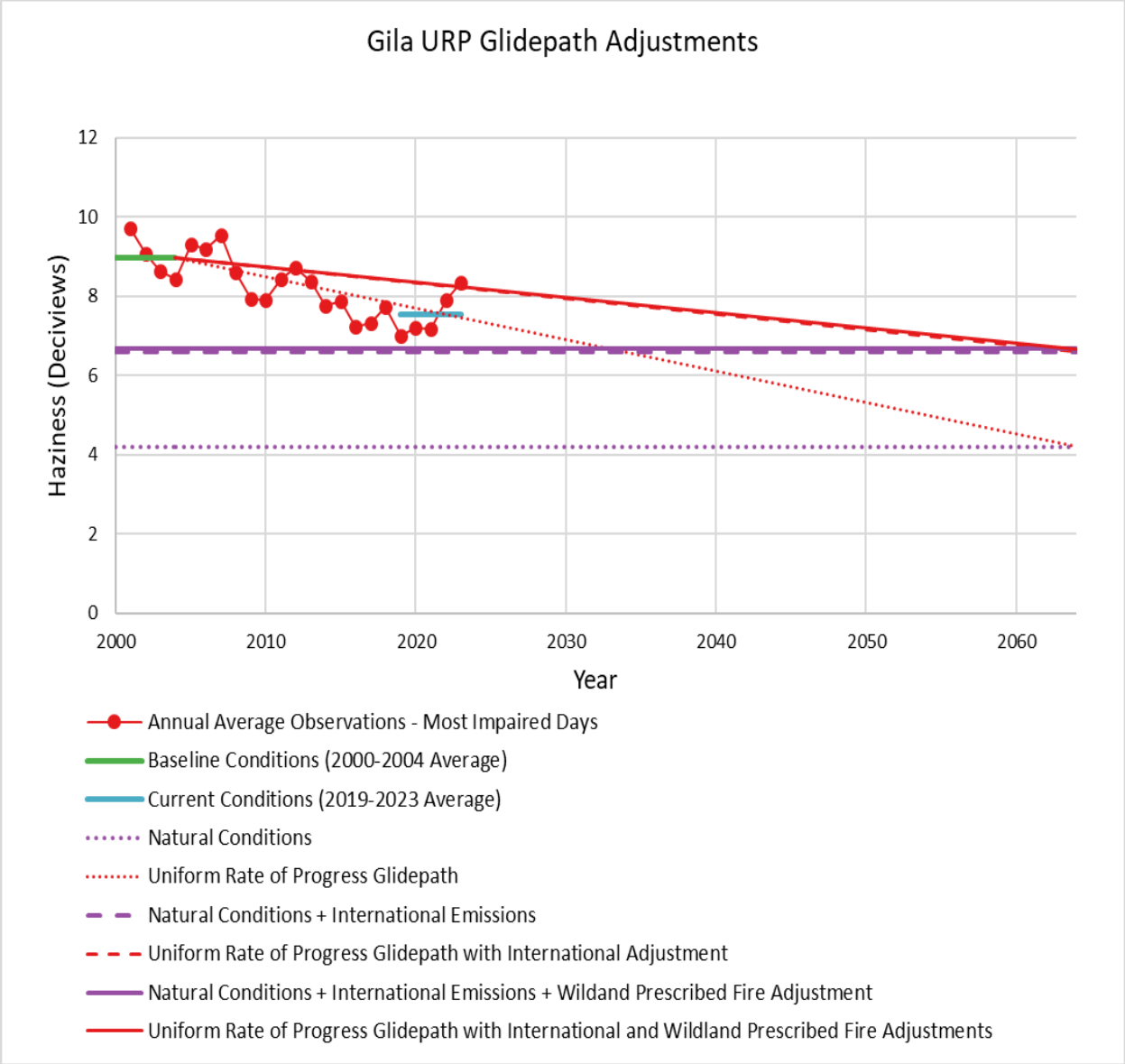


Values for GUMO1:

	Deciviews
Baseline Conditions (2000-2004 Average)	14.6
Current Conditions (2019-2023 Average)	12.5
Natural Conditions	4.8
Natural Conditions + International Emissions	9.8
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	9.9

3.6.4 Gila Wilderness Area Adjusted URP

Figure 3-13: GICL1 Adjusted URP.

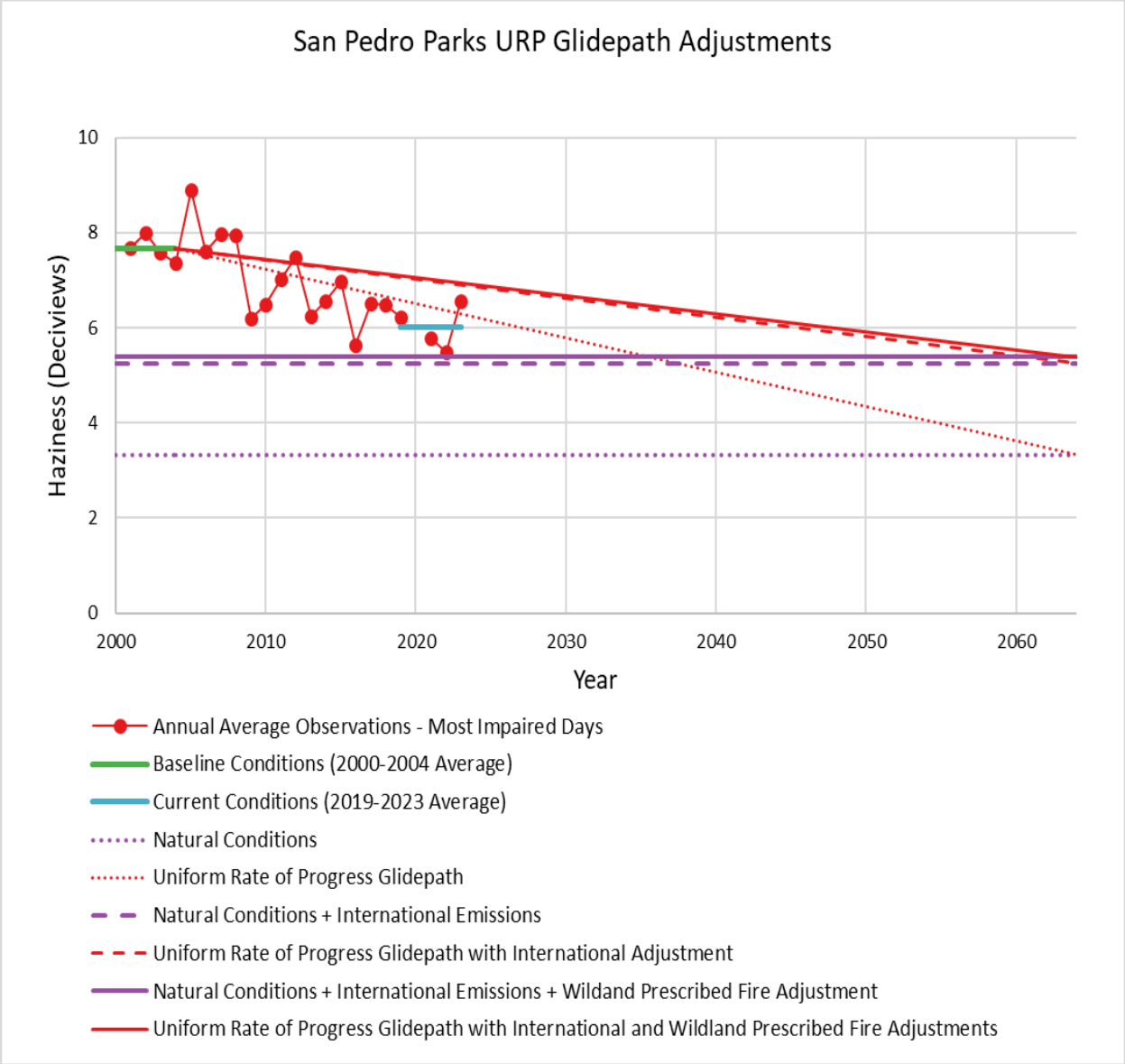


Values for GICL1:

	Deciviews
Baseline Conditions (2000-2004 Average)	9.0
Current Conditions (2019-2023 Average)	7.5
Natural Conditions	4.2
Natural Conditions + International Emissions	6.6
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	6.7

3.6.5 San Pedro Parks Wilderness Area Adjusted URP

Figure 3-14: SAPE1 Adjusted URP.

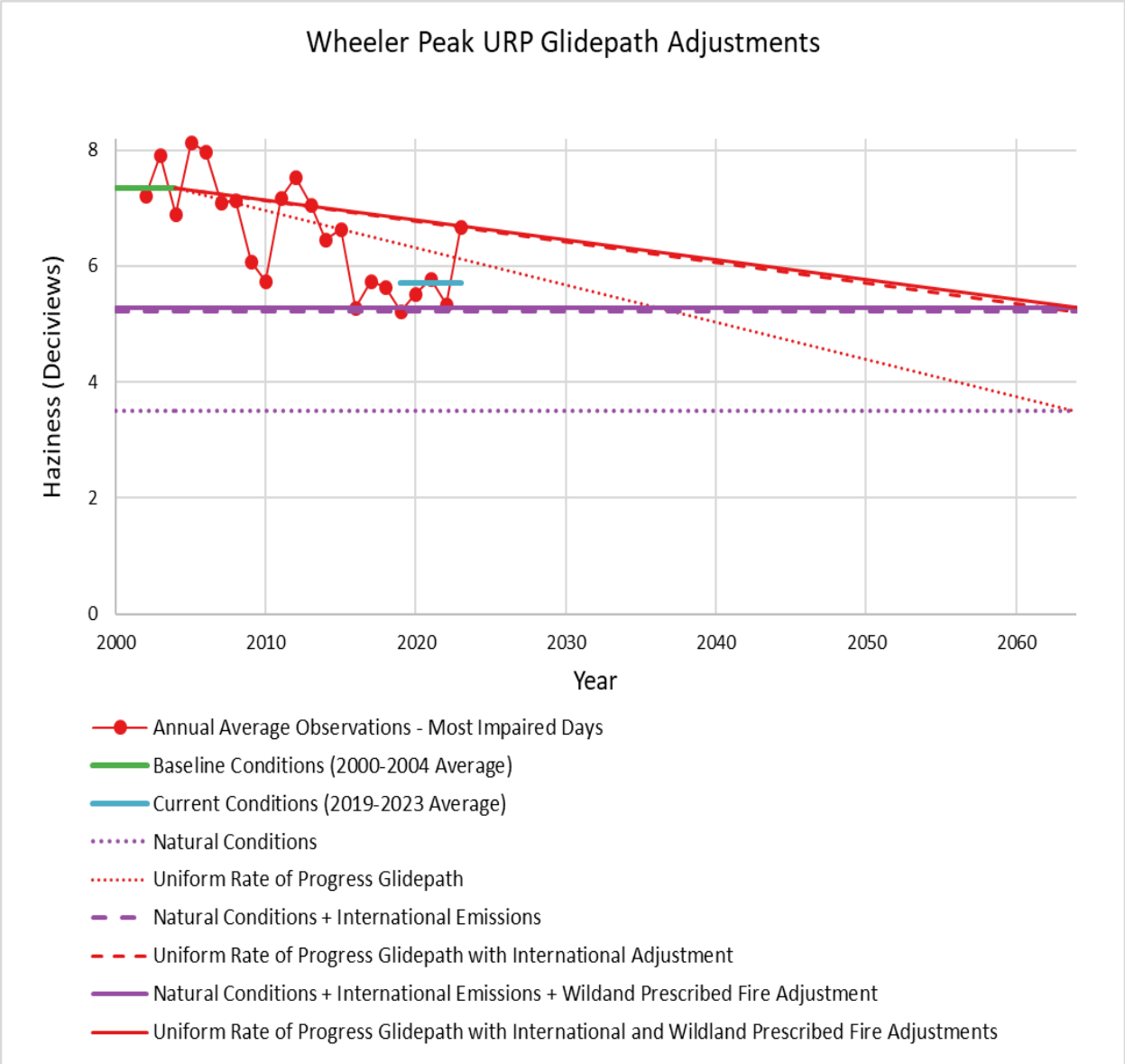


Values for SAPE1:

	Deciviews
Baseline Conditions (2000-2004 Average)	7.7
Current Conditions (2019-2023 Average)	6.0
Natural Conditions	3.3
Natural Conditions + International Emissions	5.3
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	5.4

3.6.6 Pecos Wilderness Area & Wheeler Peak Wilderness Area Adjusted URP

Figure 3-15: WHPE1 Adjusted URP.

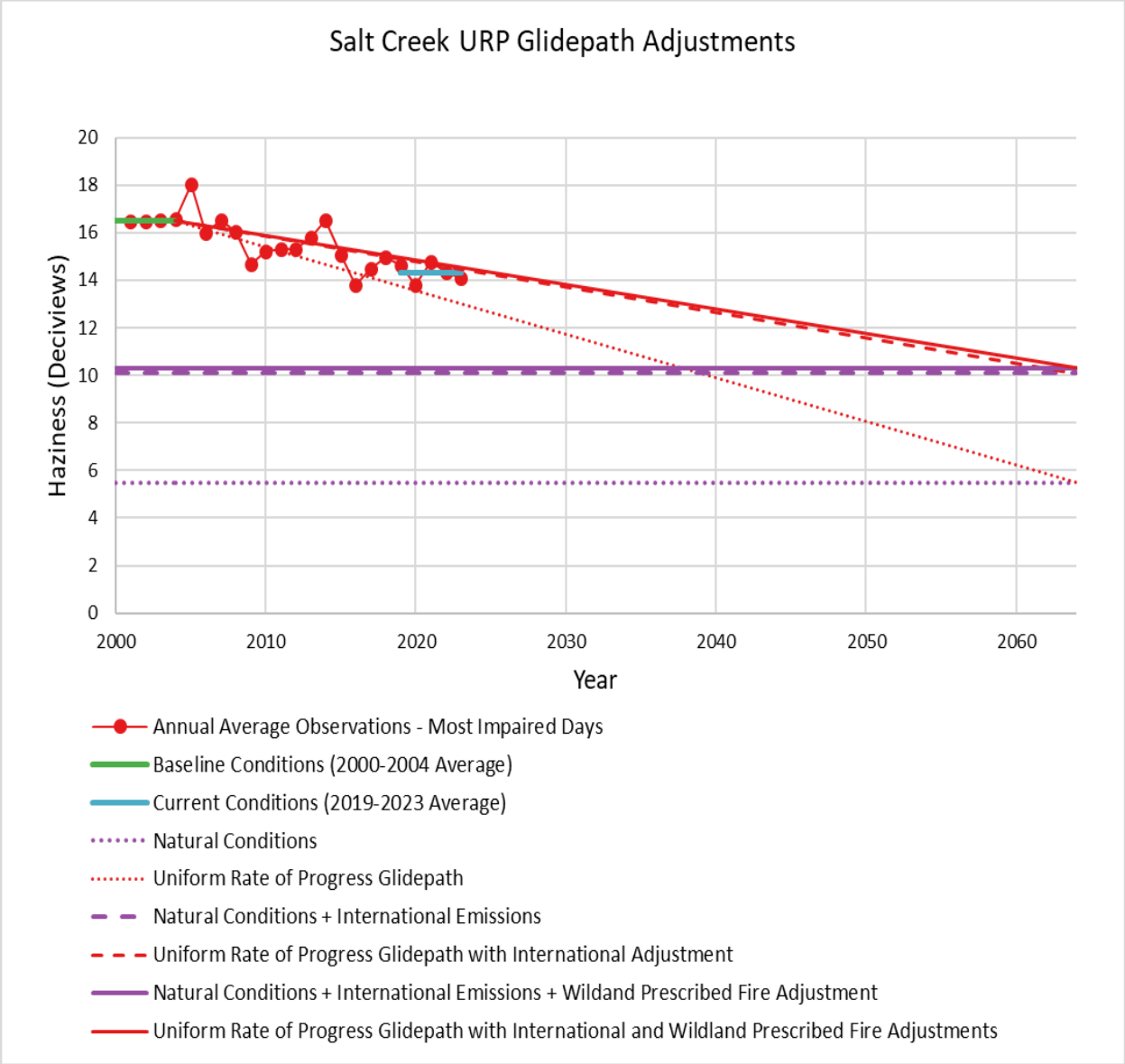


Values for WHPE1:

	Deciviews
Baseline Conditions (2000-2004 Average)	7.3
Current Conditions (2019-2023 Average)	5.7
Natural Conditions	3.5
Natural Conditions + International Emissions	5.2
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	5.3

3.6.7 Salt Creek Wilderness Area Adjusted URP

Figure 3-16: SACR1 Adjusted URP.

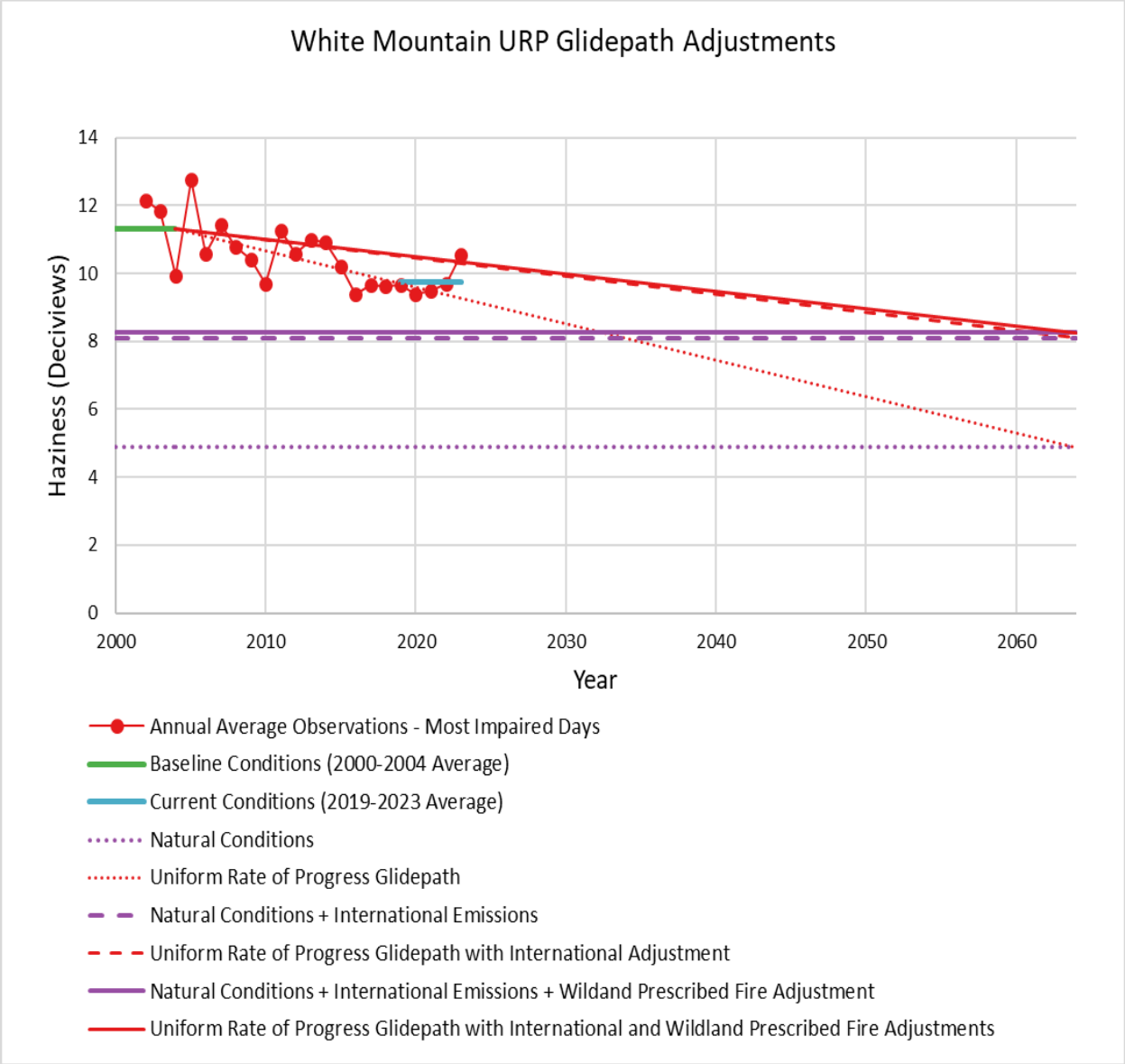


Values for SACR1:

	Deciviews
Baseline Conditions (2000-2004 Average)	16.5
Current Conditions (2019-2023 Average)	14.3
Natural Conditions	5.5
Natural Conditions + International Emissions	10.1
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	10.3

3.6.8 White Mountain Wilderness Area Adjusted URP

Figure 3-17: WHIT1 Adjusted URP.



Values for WHIT1:

	Deciviews
Baseline Conditions (2000-2004 Average)	11.3
Current Conditions (2019-2023 Average)	9.7
Natural Conditions	4.9
Natural Conditions + International Emissions	8.1
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	8.3

Chapter 4: Determination of Affected Class I Areas in Other States

4.1 Regulatory Requirements

The Regional Haze Rule requires that this Regional Haze SIPr Rd 2 (2019-2028) contain a long-term strategy that addresses regional haze visibility impairment for each Class I Area within the state and for each Class I Area located outside the state that may be affected by emissions from the state. [71] According to the U.S. Environmental Protection Agency's (EPA) August 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, states have the flexibility to use any reasonable method for quantifying the impacts of their own emissions on out-of-state Class I Areas, and they may use any reasonable assessment for this determination. [72]

4.2 New Mexico Approach

The New Mexico Environment Department (NMED) integrated its assessment of the potential impacts of New Mexico's emissions on out-of-state Class I Areas into its source selection process. In coordination with other WRAP states and Federal Land Managers (FLMs) in 2019, NMED and the City of Albuquerque Environmental Health Department (EHD) chose to use the Q/d method to select a reasonable set of sources for an analysis of control measures necessary to make reasonable progress for the second planning period. As described in Chapter 6:, this method sums the quantity of aerosol precursor pollutants emitted by a facility (Q) and divides it by the distance from the facility to the nearest Class I Area (d). This provides a screening-level estimate of the potential for pollutants from the facility to impact the Class I Area.

In determining the distance to the nearest Class I Area for the 144 Title V facilities NMED calculated Q/d scores for, NMED considered all Class I Areas, not just those located in New Mexico. Of these, 57 were closest to Class I Areas in other states, i.e., Arizona, Colorado, and Texas. As such, the Q/d scores for more than a third of the facilities NMED screened reflect their potential to impact out-of-state Class I Areas, which was deemed greater than their potential to impact New Mexico Class I Areas due to their closer proximity to out-of-state areas. NMED ultimately selected a number of these facilities for an analysis of control measures, meaning they were evaluated based on their potential to impact out-of-state areas. Approximately half of the facilities selected for an analysis on this basis would not have been selected had NMED only considered Class I Areas in New Mexico when calculating Q/d scores. As a result, NMED's source selection process reasonably accounted for the impacts of New Mexico's emissions on out-of-state Class I Areas.

4.3 Additional Evidence

NMED participated in the Western Regional Air Partnership (WRAP) Regional Haze collaboration and planning process and made use of qualitative tools that were made available through the WRAP Technical Support System (TSS), as they were made available, to help provide context and weight of evidence regarding potential out-of-state emissions impacts. In September 2020, Weighted Emissions Potential and Area of Influence products were initially made available for Regional Haze planning in the western U.S. by WRAP. The analysis was performed for the most impaired days (MID) during each year of the 5-year period from 2014 through 2018 at 76 Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites representing 116 Class I Areas in the 13 contiguous WRAP

[71] 40 CFR § 51.308(f)(2).

[72] EPA Regional Haze SIP Guidance, p. 8.

states and neighboring states. Although not available when NMED completed its source selection process, these products support the conclusion that NMED's process adequately addresses the impacts of New Mexico's emissions on out-of-state Class I Areas.

As an example, Figure 4-1 and Figure 4-2 show calculated residence times from WRAP TSS data for Mesa Verde National Park in Colorado and Guadalupe Mountains National Park in Texas. The residence time is the percentage of air parcels that arrive at a Class I Area on the 2014-2018 most impaired days traveling from various locations. The parts of New Mexico that show some potential anthropogenic influence on Mesa Verde and Guadalupe Mountains based on residence time are the San Juan Basin in the Four Corners Region in northwest New Mexico, and the greater Permian Basin in the southeast part of the state. While it is a challenging exercise to estimate with any degree of certainty what the quantitative impacts of individual point sources are at Class I Areas, especially when projecting visibility into the future, reductions of visibility-impairing pollutant emissions from sources in these areas (as well as other parts of the state) can reasonably be expected to improve visibility at Mesa Verde and Guadalupe Mountains, as well as other out-of-state Class I Areas. NMED's robust source selection, control measures determinations, and long-term strategy (described in Chapters 6, 7, and 8, respectively) provide for significant reductions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions from facilities in these areas of New Mexico.

Figure 4-1: Residence Time Plot for Mesa Verde National Park.

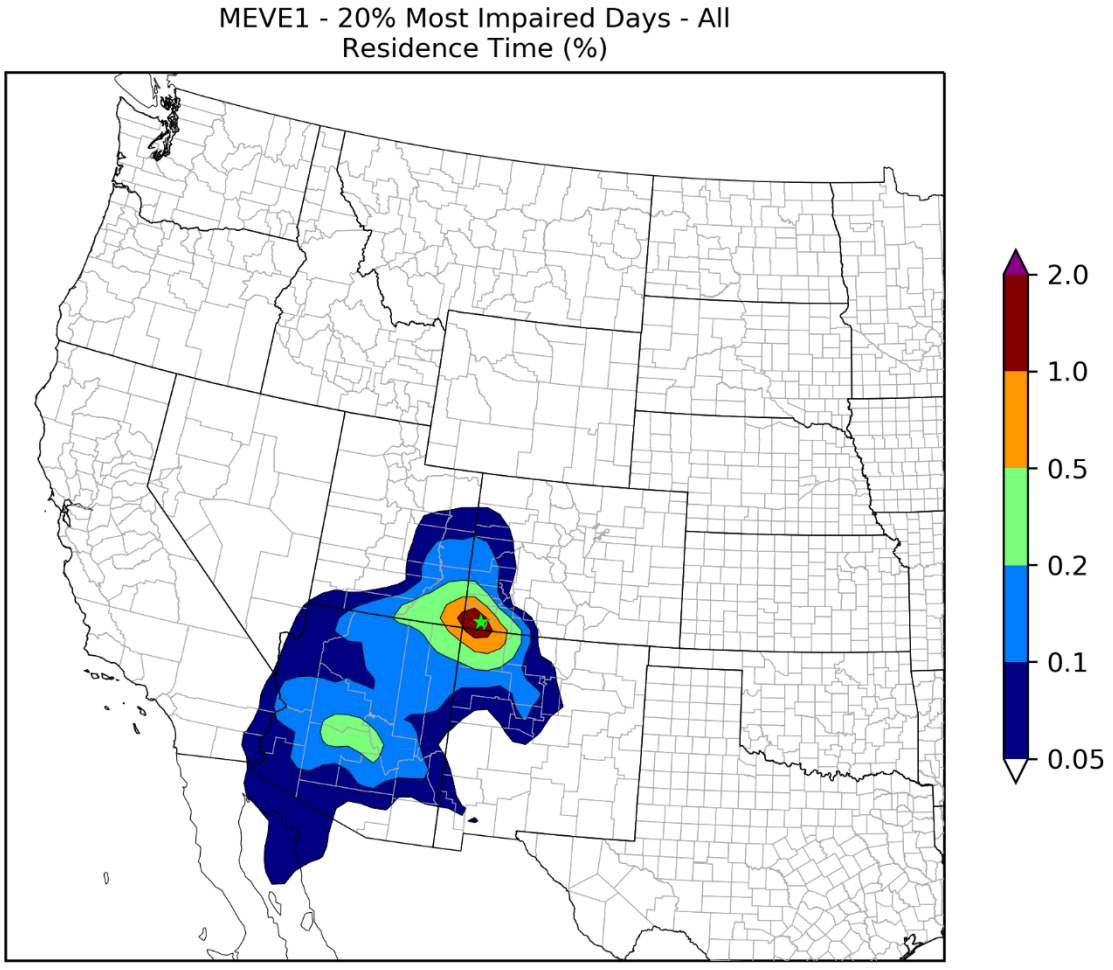
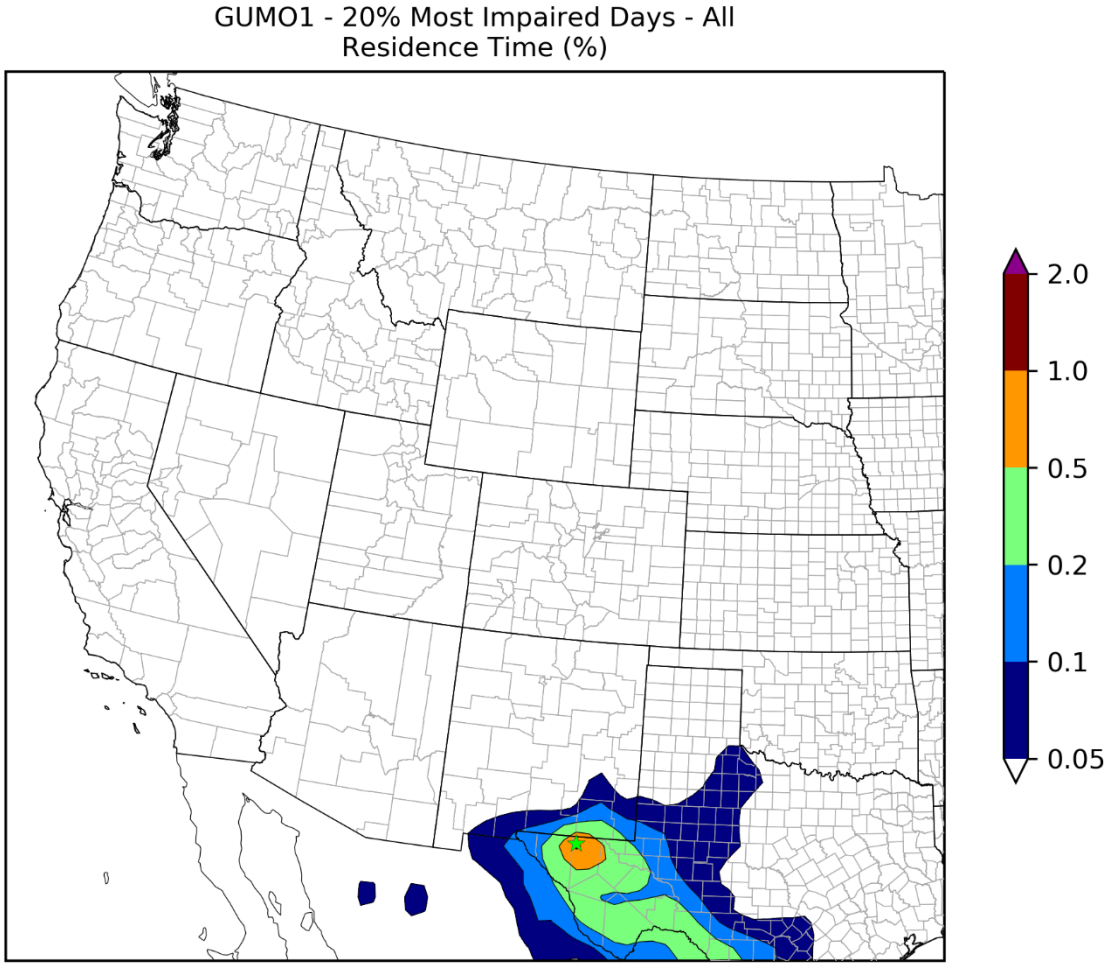


Figure 4-2: Residence Time Plot for Guadalupe Mountains National Park.



4.4 Communications with Neighboring States

NMED communicated with Arizona, Utah, and Colorado through the Western Regional Air Partnership collaborative process, and also met with Texas to discuss coordination as states were in various processes of developing their respective SIP revisions. This is discussed more in Chapter 11 - Coordination and Discussions with Other Parties. No neighboring state or other state requested that NMED select additional sources for an analysis of control measures or require the installation of controls at sources regulated by NMED to address impacts from New Mexico's emissions on any out-of-state Class I Area.

Chapter 5: Embedded Progress Report

The Regional Haze Rule requires that this Regional Haze SIPr Rd 2 (2019-2028) provide a progress report on implementation of the first planning period State Implementation Plan (SIP) during the five years following the required submittal of a mid-period progress report in 2013. [73] This Chapter provides the required progress report, covering the second half of the first planning period (i.e., 2014-2018).

The New Mexico Regional Haze SIP for the first planning period (2008-2018) was adopted under a different section of the Regional Haze Rule than this Regional Haze SIPr Rd 2 (2019-2028) is proposed under. The first planning period SIP was adopted in accordance with 40 CFR § 51.309, Requirements Related to The Grand Canyon Visibility Transport Commission ("Section 309"), whereas this second planning period SIP is proposed for adoption in accordance with 40 CFR § 51.308, Regional Haze Program Requirements ("Section 308"). Thus, the progress report in this Chapter, which satisfies Section 308 requirements, provides a progress report regarding implementation of Section 309 requirements for 2014-2018. For simplicity, this Chapter will refer to the first planning period SIP for New Mexico, adopted under Section 309, as the "First Period SIP," and will continue to refer to this SIP revision for the current (i.e., second) planning period, proposed for adoption under Section 308, as the Regional Haze SIPr Rd 2 (2019-2028). The first two Sections of this Chapter will cover, first, the Section 308 requirements that the progress report in this Chapter must satisfy and, second, the background of New Mexico's decision to adopt the First Period SIP under Section 309. That background will be useful in understanding the progress report, which is covered in the remaining 5 Sections of this Chapter.

5.1 Regulatory Requirements

The embedded progress report in this Regional Haze SIPr Rd 2 (2019-2028) must address the period since the most recent progress report, which was due in 2013 and addressed the period 2009-2013. [74] Therefore this progress report must address the period 2014-2018. As specified in 40 CFR § 51.308(f)(5), this progress report must provide the information specified in 40 CFR § 51.308(g)(1) to (7), which is described below.

1) A description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class I Federal areas both within and outside the state. [75]
2) A summary of the emissions reductions achieved throughout the state through implementation of the measures described in [40 CFR § 51.308(g)(1)]. [76]
3) For each mandatory Class I Federal area within the state, the state must assess the following visibility conditions and changes, with values for most impaired, least impaired and/or clearest days as applicable expressed in terms of 5-year averages of these annual values. The period for calculating current visibility conditions is the most recent 5-year period preceding the required date of the progress report for which data are available as of a date 6 months preceding the required date of the progress report.
    a. The current visibility conditions for the most impaired and least impaired days. [77]

[73] 40 CFR § 51.308(f)(5).
[74] 40 CFR § 51.308(f)(5); 40 CFR § 51.309(d)(10).
[75] 40 CFR § 51.308(g)(1).
[76] 40 CFR § 51.308(g)(2).
[77] 40 CFR § 51.308(g)(3)(i)(A).

b. The difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions. [78]

c. The change in visibility impairment for the most impaired and least impaired days over the period since the period addressed in the most recent plan required under paragraph (f) of this section. [79]

4) An analysis tracking the change over the period since the period addressed in the most recent plan required under [40 CFR § 51.308(f)] in emissions of pollutants contributing to visibility impairment from all sources and activities within the state. [80]

5) An assessment of any significant changes in anthropogenic emissions within or outside the state that have occurred since the period addressed in the most recent plan required under [40 CFR § 51.308(f)] including whether or not these changes in anthropogenic emissions were anticipated in that most recent plan and whether they have limited or impeded progress in reducing pollutant emissions and improving visibility. [81]

6) An assessment of whether the current implementation plan elements and strategies are sufficient to enable the state, or other states with mandatory Class I Federal areas affected by emissions from the state, to meet all established reasonable progress goals for the period covered by the most recent plan required under [40 CFR § 51.308(f)]. [82]

7) For progress reports for the first implementation period only, a review of the state's visibility monitoring strategy and any modifications to the strategy as necessary. [83]

8) For a state with a long-term strategy that includes a smoke management program for prescribed fires on wildland that conducts a periodic program assessment, a summary of the most recent periodic assessment of the smoke management program including conclusions if any that were reached in the assessment as to whether the program is meeting its goals regarding improving ecosystem health and reducing the damaging effects of catastrophic wildfires. [84]

Following the 8-step framework outlined in the U.S. Environmental Protection Agency's (EPA) August 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, this Chapter covers the progress report elements described in 40 CFR § 51.308(g)(1) to (5). Chapter 12 of this Regional Haze SIPr Rd 2 (2019-2028) covers the progress report elements described in 40 CFR § 51.308(g)(6) and (7).

5.2 Background on Section 309 of the Regional Haze Rule

The federal Clean Air Act (CAA) provides the EPA Administrator with the authority to establish a visibility transport region for any area of at least two states where the Administrator has reason to believe that the current or projected interstate transport of air pollutants from one or more states contributes significantly to visibility impairment in Class I Areas located in the affected states. [85] The CAA directs the EPA Administrator to also establish a visibility transport commission whenever the Administrator

[78] 40 CFR § 51.308(g)(3)(ii)(A).
[79] 40 CFR § 51.308(g)(3)(iii)(A).
[80] 40 CFR § 51.308(g)(4).
[81] 40 CFR § 51.308(g)(5).
[82] 40 CFR § 51.308(g)(6).
[83] 40 CFR § 51.308(g)(7).
[84] 40 CFR § 51.308(g)(8).
[85] 42 U.S.C. § 7492(c)(1).

establishes a visibility transport region and provides specific direction on the composition of such a commission.[86] The CAA additionally specifies the duties of visibility transport commissions, which include: assessing scientific and technical data, studies, and other currently available information pertaining to adverse impacts on visibility from potential or projected growth in emissions from sources located in the visibility transport region; and, within four years of establishment, issuing a report to the EPA Administrator recommending what measures, if any, should be taken to remedy such adverse impacts.[87] Once such a report is issued, the CAA allows EPA 18 months to carry out its regulatory responsibility to promulgate a regional haze rule under 42 U.S.C. § 7491.[88] The CAA also expressly provides for the establishment of such a visibility transport commission - the Grand Canyon Visibility Transport Commission (GCVTC) - for the region affecting the visibility of Grand Canyon National Park.[89]

The EPA established the GCVTC in November 1991 for the Grand Canyon visibility transport region, which spans nine states (Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming) and 211 Tribal lands on the Colorado Plateau.[90] Members included the governors or their designees of each state in the region (with the exception of Idaho, which chose not to participate in the GCVTC); the leaders of the Navajo, Hopi, Hualapai, and Acoma Pueblo Tribes, or their designees; and ex officio members including EPA, federal land managers from the National Park Service, Bureau of Land Management, U.S. Fish and Wildlife Service, and U.S. Forest Service, and the Columbia River Inter-Tribal Fish Commission.[91] The GCVTC, following the instructions in 42 U.S.C. § 7492, issued a final report in June 1996 recommending long range strategies for addressing regional haze that impairs visibility in Class I Areas on the Colorado Plateau.[92] As required by the CAA, the EPA then promulgated the original Regional Haze Rule in July 1999. The Regional Haze Rule provided two paths for states to address regional haze. The first path, Section 308, required states to perform individual point source Best Available Retrofit Technology (BART) determinations and evaluate the need for other control strategies. The other path, Section 309, allowed the nine states in the Grand Canyon visibility transport region - and the 211 Tribes within those states - to implement the GCVTC's recommendations from its June 1996 report to address visibility impairment in the 16 Class I Areas on the Colorado Plateau. Five states - Arizona, New Mexico, Oregon, Utah, and Wyoming - as well as Albuquerque - Bernalillo County submitted their First Period SIPs under Section 309 by the December 31, 2003 deadline. Oregon ceased

[86] 42 U.S.C. § 7492(c)(2).
[87] 42 U.S.C. § 7492(d).
[88] 42 U.S.C. § 7492(e)(1).
[89] 42 U.S.C. § 7492(f).
[90] The Grand Canyon Visibility Transport Commission, Recommendations for Improving Western Vistas (June 10, 1996), "GCVTC Report", pp. i to 91.
[91] GCVTC Report, p. 3.
[92] *Id*.

participating in the program in 2006, followed by Arizona in 2010.[93, 94] While Tribes are not subject to the deadline and can still opt into the Section 309 program at any time, none have done so.

The EPA revised the Regional Haze Rule on July 6, 2005 and again on October 13, 2006 in response to two legal challenges.[95, 96] The October 13, 2006 revisions modified Section 309 to provide a methodology consistent with the Court's decision for evaluating the equivalence of alternatives to BART, such as the alternative Section 309 strategy based on the GCVTC recommendations. The Regional Haze Rule was revised again on January 10, 2017, requiring all states - including Section 309 states - to comply with Section 308 requirements in their periodic implementation plan revisions.[97] In the preamble to the January 10, 2017 final rule, EPA clarified that all measures and obligations contained in a state's First Period SIP submitted under Section 309 must continue to be implemented unless the SIP itself provides for that measure or obligation to sunset; that the revised provisions of Section 309 will apply to any SIP revision that would revise a First Period SIP provision that was part of the basis of EPA initially approving the First Period SIP as meeting the requirements of Section 309 of the original Regional Haze Rule; and that future periodic comprehensive SIP revisions and progress reports from the Section 309 states - including this Regional Haze SIPr Rd 2 (2019-2028) - will be subject to the requirements of Section 308.[98]

5.3 Implementation Status of All Control Measures in First Period SIP

The progress report must provide: "A description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class I Federal areas both within and outside the state."[99]

This Section describes control measures in New Mexico's First Period SIP that were adopted for the first Regional Haze planning period to regulate anthropogenic sources of haze-causing pollutants in New Mexico. For each control measure, this Section describes the pollutant being controlled, the method of control and how it affects visibility, the type of source affected, and the extent to which any applicable compliance date for sources has come into effect.

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[93] "In 2003, Oregon did submit a Section 309 Regional Haze Plan, to primarily address the contribution of Oregon emissions to visibility impacts in the Colorado Plateau. This plan, along with 4 other state plans submitted under Section 309, were disapproved by EPA due to a lawsuit regarding the BART requirements in Section 309. [For more information see *Center for Energy and Economic Development v. EPA*, no. 03-1222, (D.C. Cir. Feb. 18, 2005)("CEED v. EPA")]. The four states chose to resubmit their 309 plans. The Department decided not to resubmit the plan, due to the optional nature of Section 309, the fact that Oregon is only a minor contributor to visibility impacts in the Colorado Plateau, and that a Section 308 plan is required in 2008 regardless under the Regional Haze Rule." Oregon Regional Haze Plan, December 2009, p. 9.

[94] "Originally, Arizona was to submit a SIP addressing both Section 309(d)(4) and Section 309(g); however, it was determined in 2010 that EPA did not approve of the revisions to the milestone program. To avoid a FIP, EPA requested that Arizona submit a plan under Section 308. Arizona agreed but with the understanding that all the work done on the previously submitted plans would be recognized and that the important long-term strategies would be incorporated into the 308 SIP as would have been the case under Section 309(g) except now for all 12 of Arizona's national parks and wilderness areas." Final Arizona Regional Haze SIP – 308, January 2011, p. 9.

[95] 70 Fed. Reg. 39104 (July 6, 2005) (Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations).

[96] 71 Fed. Reg. 60612 (October 13, 2006) (Regional Haze Regulations; Revisions to Provisions Governing Alternative to Source-Specific Best Available Retrofit Technology (BART) Determinations).

[97] 82 Fed. Reg. 3078 (January 10, 2017) (Protection of Visibility: Amendments to Requirements for State Plans.)

[98] *Id*.

[99] 40 CFR § 51.308(g)(1).

5.3.1 SO_2 Milestone and Backstop Trading Program

The Regional Haze Rule requires Section 309 states to develop an emissions reduction program for stationary sources of sulfur dioxide (SO_2).[100] To meet this requirement, the First Period SIPs for New Mexico, Albuquerque – Bernalillo County, and the other Section 309 states (Utah and Wyoming) provided for an SO_2 Milestone and Backstop Trading program that:

- tracks SO_2 emissions from major stationary sources reporting 100 tons per year or more of SO_2 emissions;
- requires that total emissions from the SO_2 sources tracked remain at or below specific annual milestones; and
- in the event an annual milestone is exceeded, requires implementation of a regional SO_2 emissions trading system among the three Section 309 states.

Under its First Period SIP, New Mexico cooperates with its Western Regional Air Partnership (WRAP) partners (including Albuquerque - Bernalillo County) to maintain an inventory of regional SO_2 emissions across the Section 309 states. Annual regional emissions must not exceed specific milestones for each year, which have gradually decreased over time. If an annual regional milestone is exceeded, then a regional backstop trading program (Western Backstop SO_2 Trading Program) will be triggered to bring emissions below the milestone.

Once triggered, the trading program would require New Mexico to allocate "allowances" to each source for specific maximum permissible amounts of SO_2 emissions. Sources would be allowed to trade allowances in order to comply with source-specific emissions targets. A tracking system would be used to manage emissions monitoring, allowances allocation, and allowances trading. This backstop SO_2 trading program has been adopted in the currently effective rule, 20.2.81 NMAC, Western Backstop Sulfur Dioxide Trading Program. However, the program, by design, will not be implemented unless the annual regional SO_2 milestones are exceeded. Only at that time would applicable compliance dates for specific regulatory provisions under 20.2.81 NMAC become effective. New Mexico is prepared to implement the SO_2 backstop trading program if it becomes necessary in the future.

20.2.73 NMAC, Notice of Intent and Emissions Inventory Requirements, requires major industrial sources of SO_2 to submit an annual emissions inventory in the pre-trigger phase of the program to measure compliance with the regional SO_2 milestones. If the backstop program is triggered, then these requirements will eventually be replaced by more rigorous monitoring requirements in 20.2.81 NMAC.

Table 5-1 presents the adjusted actual regional SO_2 emissions for 2014 - 2022 in tabular form. Figure 5-1 presents the adjusted actual regional SO_2 emissions for 2003-2022 in graphical form. Each year, adjusted actual SO_2 emissions were well below the regional milestone. Consequently, the backstop trading program was not triggered.

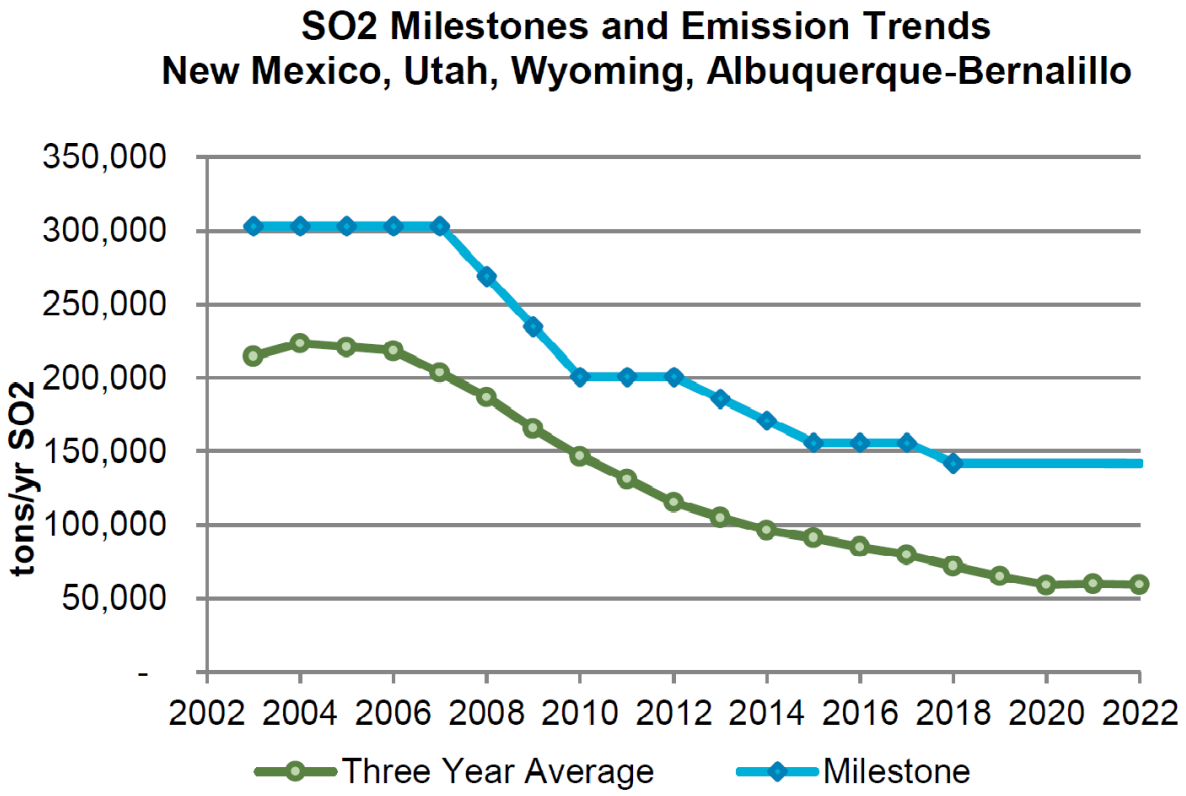
[100] 40 CFR § 51.309(d)(4).

Table 5-1: 2014 - 2022 Regional SO2 Milestones and Emission Trends in Section 309 States. [101]

Year	SO_2 Milestone (tons)	Adjusted Actual SO_2 Emissions (tons) [102]	3-Yr Avg. Adjusted SO_2 Emissions (tons)	Difference between Milestone and 3-Yr Avg. Adjusted SO_2 Emissions [103]	3-Yr Avg. Adjusted SO_2 Emissions as a Percent of Milestone	Adjusted Actual SO_2 Emissions as a Percent of Milestone
2014	170,868	92,553	96,392	<74,476>	56%	NA
2015	155,940	81,454	91,310	<64,630>	59%	NA
2016	155,940	98,035	90,591	<65,349>	58%	NA
2017	155,940	76,504	79,709	<76,231>	51%	NA
2018	141,849	71,994	NA	<69,854>	NA	51%
2019	141,849	65,001	NA	<76,847>	NA	46%
2020	141,849	59,352	NA	<82,496>	NA	42%
2021	141,849	60,011	NA	<81,837>	NA	42%
2022	141,849	59,364	NA	<82,485>	NA	42%

[101] The full content of the SO_2 Emissions and Milestone Reports for the years 2015 to 2022 are available at https://westar.org/regional-haze/. Earlier reports are available at https://www.wrapair2.org/reghaze.aspx.
[102] The First Period SIPs require states to adjust reported emissions to account for changes in monitoring, calculation methods, and enforcement actions.
[103] From 2003 to 2017 states compared the milestone to a three-year average of adjusted region-wide SO_2 emissions as required by the First Period SIPs. The First Period SIPs require states to compare the final 2018 regional milestone to 2018 emissions rather than the three-year average. Negative Value = Emissions < Milestone

Figure 5-1: 2003 - 2022 SO2 Milestones and Emission Trends.



5.3.2 Best Available Retrofit Technology

The San Juan Generating Station (SJGS) is the only facility in New Mexico that was subject to a BART determination during the first Regional Haze planning period. At that time, SJGS consisted of four coal-fired boilers: Unit 1 (1976) at 370 megawatts (MW), Unit 2 (1973) at 350 MW, Unit 3 (1979) at 544 MW, and Unit 4 (1982) at 544 MW. On November 27, 2012, EPA published final approval of New Mexico's 2003 and 2011 SIP submittals but expressly declined to take action on the portion of the 2011 SIP making a nitrogen oxides (NO_X) BART determination for SJGS, which consisted of selective non-catalytic reduction (SNCR) with an emission rate of 0.23 lbs/MMBtu.[104] EPA had previously issued a Federal Implementation Plan (FIP) containing a different NO_X BART determination for SJGS.[105] In its final rule, EPA determined that a NO_X emission limit from the SJGS of no greater than 0.27 – 0.28 lbs./MMBtu was necessary to satisfy the requirements of Section 110(a)(2)(D)(i)(II) of the CAA (visibility prong), and that no other additional reductions in New Mexico were required under that section.[106] Although New Mexico's July 5, 2011 NO_X BART determination of 0.23 lbs/MMBtu represented a lower emission rate than EPA determined to be necessary to satisfy Section 110(a)(2)(D)(i)(II), EPA promulgated its own NO_X BART determination of 0.05 lbs/MMBtu based on selective catalytic reduction (SCR).

[104] 77 Fed. Reg. 70693 (November 27, 2012) (Approval and Promulgation of State Implementation Plans; State of New Mexico; Regional Haze Rule Requirements for Mandatory Class I Areas).
[105] 76 Fed. Reg. 52388 (August 22, 2011) (Approval and Promulgation of Implementation Plans; New Mexico; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determination).
[106] *Id*. at 52424.

New Mexico challenged EPA's NO_X BART FIP for SJGS, and the case was filed in the U.S. Court of Appeals for the Tenth Circuit. New Mexico, EPA, and the Public Service Company of New Mexico (PNM, operator of the SJGS) reached a tentative agreement (contained in a "Term Sheet") on February 15, 2013 on an alternative plan to address pollution control requirements for the SJGS under the Clean Air Act's requirements for regional haze and interstate transport for visibility. The agreement called for a new BART determination based on the retirement of Units 2 and 3 at the facility by December 31, 2017; the installation of SNCR technology on the remaining Units 1 and 4, with a NO_X emission rate of no greater than 0.23 lbs/MMBtu; and further reductions in SO_2 emissions. On September 5, 2013, the Environmental Improvement Board (EIB) unanimously approved a SIP revision incorporating the terms of the tentative agreement as a revised BART determination. The revised SIP was submitted to EPA on October 8, 2013, and on December 17, 2013, EPA determined that the revised SIP submission was administratively complete.

On October 9, 2014, EPA approved a revision to the New Mexico Regional Haze SIP that addressed BART for SJGS, making the emission limitations federally enforceable, and satisfying CAA 110(a)(2)(D)(i)(II) with respect to interstate transport of air pollution and visibility protection for the 8-hour ozone and fine particulate matter ($PM_{2.5}$) National Ambient Air Quality Standards (NAAQS). [107] At the same time, EPA withdrew its FIP for New Mexico that applied to SJGS. [108] Therefore, the requirement for New Mexico under Section 110(a)(2)(D)(i)(II) is satisfied by the SIP revisions approved on November 27, 2012.

Units 2 and 3 were shut down at the end of 2017 in accordance with the approved, revised BART determination for SJGS. Table 5-2 shows NO_X and SO_2 emission reductions resulting from the implementation of BART at SJGS through to the end of 2018.

Table 5-2: San Juan Generating Station Declining NOx and SO2 emissions resulting from the implementation of BART through to the end of the first planning period, Dec 31, 2018. [109]

	NO_X (tons)	SO_2 (tons)
2008	22,158	10,619
2009	18,359	5,517
2010	15,775	4,292
2011	17,101	4,720
2012	15,975	4,604
2013	16,817	6,055
2014	16,562	4,970
2015	14,531	3,515
2016	14,902	2,928
2017	16,181	4,525
2018	6,403	1,247

[107] 79 Fed. Reg. 60985 (October 9, 2014) (Approval and Promulgation of Implementation Plans; New Mexico; Regional Haze and Interstate Transport Affecting Visibility State Implementation Plan Revisions).
[108] 79 Fed. Reg. 60978 (October 9, 2014) (Approval and Promulgation of Implementation Plans; New Mexico; Regional Haze and Interstate Transport Affecting Visibility State Implementation Plan Revisions; Withdrawal of Federal Implementation Plan for the San Juan Generating Station).
[109] Source: https://campd.epa.gov/data/.

5.3.3 New Source Review Program

The New Source Review (NSR) Program is a permit program for the construction of new stationary sources and modification of existing stationary sources established by 20.2.72 NMAC – Construction Permits; 20.2.74 NMAC – Permits – Prevention of Significant Deterioration; and 20.2.79 NMAC – Permits – Nonattainment Areas. The primary purposes of the NSR Program are to assure compliance with the NAAQS, which provide public health protection; assure that Best Available Control Technology is utilized for major facilities subject to 20.2.74 NMAC to prevent deterioration of air quality in areas that are attaining the NAAQS; and assure that the Lowest Achievable Emission Rate and emission offsets are required for major facilities subject to 20.2.79 NMAC to move areas that are not attaining the NAAQS towards attainment. New Mexico has been granted the authority by EPA to implement the state's NSR Program, and all state regulations are up to date with 40 CFR § 51.166. [110].

20.2.79 NMAC sets forth permitting requirements for new major stationary sources or major modifications of existing stationary sources if those sources will be: (1) located within a nonattainment area so designated pursuant to Section 107 of the CAA and will emit a regulated pollutant for which it is major and which the area is designated nonattainment for; or (2) located within an area designated as attainment or unclassifiable for any NAAQS pursuant to Section 107 of the CAA, when it would cause or contribute to a violation of any NAAQS. A major source or major modification will be considered to cause or contribute to a violation of a NAAQS when such source or modification would, at a minimum, exceed any of the significance levels in Subsection A of 20.2.79.119 NMAC at any location that does not or would not meet the applicable national standard. [111]

The EPA designated a portion of Doña Ana County near Sunland Park, New Mexico as a marginal nonattainment area for the 2015 Ozone NAAQS on August 3, 2018, requiring a determination of adequacy of 20.2.79 NMAC, and submittal to EPA by August 3, 2021.20.2.79 NMAC was subsequently analyzed to determine if it was adequate to implement and enforce the standard. The AQB compared 20.2.79 NMAC with 40 CFR § 51.165, Permit Requirements, and identified certain inconsistencies and errors. On June 25, 2021, at a hearing before the EIB, the AQB presented proposed amendments to make technical and administrative corrections to the rule which were adopted by the EIB. This proposed SIP revision was submitted to EPA on August 10, 2021, and approved on November 16, 2022, effective December 16, 2022. [112]

New Mexico's Prevention of Significant Deterioration (PSD) program is protective of visibility impairment from proposed major stationary sources or major modifications to existing facilities. New Mexico has a fully approved PSD program and has successfully implemented this program since 1984. [113]

[110] Progress Report for the SIP for Regional Haze, March 11, 2014, p. 8.
[111] See Subsection D of 20.2.79.109 NMAC.
[112] 87 Fed. Reg. 68632 (November 16, 2022) (Air Plan Approval; New Mexico; Clean Air Act Requirements for Nonattainment New Source Review Permitting for the 2015 8-Hour Ozone National Ambient Air Quality Standards).
[113] Progress Report for the SIP for Regional Haze, March 11, 2014, p. 8.

5.3.4 Mobile Sources

Section 309 of the Regional Haze Rule required the First Period SIP to perform projections demonstrating a continuous decline in mobile source emissions [114] from 2003 to 2018. [115] If projected emissions did not in fact demonstrate a continuous decline forecast to occur over that period, then the First Period SIP would have been required to consider other control measures for mobile sources. [116] Such consideration was not necessary because the First Period SIP did in fact demonstrate a projected continuous decline in mobile source emissions for the period 2003 to 2018. Section 309 also required an interim report to EPA and the public in the year 2018 on the status of regional and local control strategies for mobile sources. [117] The progress report in this Chapter addresses that requirement (see Section 5.4.5 – Mobile Sources).

5.3.5 Fire/Smoke Management

Section 309 of the Regional Haze Rule required the First Period SIP to include programs for managing visibility-impairing emissions caused by prescribed fire sources. [118] In 2003, the EIB adopted 20.2.65 NMAC - Smoke Management, effective December 31, 2003. The AQB subsequently developed the state Smoke Management Program (SMP) to protect the health and welfare of New Mexicans from the impacts of smoke from all sources of fire. This SMP meets the requirements of the CAA and the Regional Haze Rule.

The SMP is applicable in all of New Mexico, except for Tribal lands and Bernalillo County, which are separate air quality jurisdictions. Burners must also comply with all city and county ordinances relating to smoke management and vegetation burning. The New Mexico Smoke Management Program Guidance Document was revised May 25, 2005, to assist burners in understanding the requirements and aid in the implementation of 20.2.65 NMAC. [119] The First Period SIP contained all elements required by Section 309. It continues to provide fire and smoke management programs under 20.2.65 NMAC - Smoke Management, to help control prescribed fire-related emissions of volatile organic compounds (VOC), NO_X, elemental carbon, organic carbon, and $PM_{2.5}$. The regulation requires that most prescribed burning in New Mexico be conducted under a permit (registration) from the AQB subject to specific requirements, including: reporting of emissions for use in emissions inventories; consideration of alternatives to burning; use of enhanced smoke management techniques recommended by the WRAP; and use of specific emission reduction techniques. The AQB implemented this regulation throughout the period since the most recent progress report and continues to rely on this regulation to achieve its fire and smoke management goals. The AQB is not proposing amendments to this regulation at this time.

[114] For the Regional Haze Rule definition of the term "continuous decline in mobile source emissions," *see* 40 CFR § 309(b)(6). The "continuous decline" is a decline in "the projected level of emissions" from mobile sources, forecast to occur in the future, after submittal of the First Period SIP.
[115] 40 CFR § 51.309(d)(5)(i).
[116] 40 CFR § 51.309(d)(5)(i)(A).
[117] 40 CFR § 51.309(d)(5)(ii). This regulatory provision requires a report on implementation status of mobile source control strategies recommended by the predecessor organization to WRAP, the GCVTC. For purposes of the progress report presented in this Chapter, the relevant control strategy being discussed here is the projection made in the First Period SIP of a continuous decline in mobile source emissions for the years 2003 to 2018.
[118] 40 CFR § 309(d)(6).
[119] Progress Report for the SIP for Regional Haze, March 11, 2014, p. 9.

5.3.6 Fugitive and Unpaved Road Dust

Section 309 of the Regional Haze Rule required the First Period SIP to include an assessment of the impact on visibility conditions in the 16 Class I Areas on the Colorado Plateau of regional-scale dust emissions by WRAP states from paved and unpaved roads.[120] If such dust emissions are determined to be a significant contributor to visibility impairment in these Class I Areas, then a SIP must implement emissions management strategies to address the impact as necessary and appropriate. The First Period SIP conducted the required assessment and determined, based on WRAP data, that regional-scale dust emissions for the purpose of the Regional Haze Rule were not a significant contributor to visibility impairment within the 16 Colorado Plateau Class I Areas.

5.3.7 Pollution Prevention - Renewable Energy Goals

Section 309 of the Regional Haze Rule required that the First Period SIP describe programs that New Mexico and Albuquerque - Bernalillo County would rely upon for the state's contribution toward renewable energy goals set forth by the GCVTC for states in the Grand Canyon visibility transport region.[121] Those goals provided that ". . . [renewable energy] will comprise 10% of [the power needs in transport region states] by 2005 and 20% by 2015."[122] Consistent with the GCVTC goals and the intent of the programs described, available information on renewable energy's role in meeting New Mexico's power needs indicates increasing reliance on such energy over time. The U.S. Energy Information Administration estimates that in 2018 wind power accounted for almost 19% of New Mexico's electricity generation, utility scale solar photovoltaic accounted for 4%, and small scale, customer-sited solar photovoltaic accounted for about 1%.[123]

In addition, the New Mexico Renewable Energy Act, as amended, requires that the state's publicly owned electric utilities obtain 15% of their total retail sales from renewable energy by 2015 and 20% by 2020, with smaller, additional requirements for percentages of retail electricity sales applicable to rural electric cooperatives for these years.[124] New Mexico's governor signed amendments to this state law in

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[120] 40 CFR § 309(d)(7).

[121] 40 CFR § 51.309(d)(8)(vi). Section 309 did not require numerical quantification (for example, as a percentage) of New Mexico's "contribution" toward the GCVTC regional renewable energy goals. Accordingly, the First Period SIPs for New Mexico and Albuquerque - Bernalillo County described the state's contribution in terms of numerous renewable energy programs whose implementation would be consistent with the regional renewable energy goals. Section 309 also required the First Period SIP to describe or provide for several other pollution prevention programs. 40 CFR § 51.309(d)(8)(i) to (v). EPA found that the First Period SIP met these requirements. 77 Fed. Reg. 70693 (November 27, 2012) (Approval and Promulgation of State Implementation Plans; State of New Mexico; Regional Haze Rule Requirements for Mandatory Class I Areas).

[122] GCVTC, Recommendations for Improving Western Vistas (June 1996), p. 35. Section 309 did not define "renewable energy". It did define "eligible renewable energy resource" as "electricity generated by non-nuclear and non-fossil low or no air emission technologies." 40 CFR § 51.309(b)(13). The latter term does not appear in the Regional Haze Rule.

[123] U.S. Energy Information Administration, New Mexico State Profile and Energy Estimates (last updated February 20, 2020), available at https://www.eia.gov/state/analysis.php?sid=NM, accessed August 14, 2020.

[124] These requirements are codified in NMSA 1978 § 62-15-34 (setting renewable energy portfolio requirements for rural electric cooperatives); NMSA 1978 § 62-16-4 (setting renewable energy portfolio requirements for publicly owned utilities). Although the state legislature has amended these statutes several times during the first and second Regional Haze planning periods, these amendments did not change the obligation of publicly owned electric utilities and rural electric cooperatives to meet the retail electricity sale requirements for 2015 and 2020 noted above.

2019 requiring publicly owned electric utilities to account for 40% of retail electricity sales from renewables by 2025, 50% by 2030, 80% by 2040, and 100% by 2045, with smaller, additional requirements for percentages of retail sales by rural electric cooperatives during the same time span. [125]

This control measure was limited to the period of time through 2018 and will not be further addressed in this Regional Haze SIPr Rd 2 (2019-2028) or in subsequent progress reports.

5.3.8 Implementation of Additional GCVTC Recommendations

Section 309 of the Regional Haze Rule required that the First Period SIP provide for implementation of all other recommendations in the GCVTC's report that can be practicably included as enforceable emission limits, schedules of compliance, or other enforceable measures (including economic incentives) to make reasonable progress toward remedying existing and preventing future regional haze in the 16 Class I Areas on the Colorado Plateau. [126] Section 309 states must provide a report to EPA and the public in 2018 on the progress toward developing and implementing policy or strategy options recommended in the GCVTC's report.

The First Period SIP evaluated the GCVTC's 1996 report, Recommendations for Improving Western Vistas, to first determine which recommendations were not already incorporated into 40 CFR § 51.309, and then to determine whether any of those additional recommendations could be practicably included in the First Period SIP. After this evaluation, none of the GCVTC's additional recommendations that were not already incorporated into 40 CFR § 51.309 were included in the First Period SIP, which noted a lack of supporting modeling or technical guidance from WRAP necessary to evaluate the additional recommendations. This situation has not changed as of the submittal of this Regional Haze SIPr Rd 2 (2019-2028). Further, New Mexico is proposing that this Regional Haze SIPr Rd 2 (2019-2028) be adopted under Section 308, with an accordingly different process for assessing potential new control measures necessary to make reasonable progress at Class I Areas potentially affected by New Mexico emissions. [127] Therefore, this Regional Haze SIPr Rd 2 (2019-2028) will not further evaluate the additional recommendations of the GCVTC.

This control measure was limited to the first planning period and will not be further addressed in this Regional Haze SIPr Rd 2 (2019-2028) or in subsequent progress reports.

5.4 Summary of Emission Reductions Achieved by Control Measure Implementation

The progress report must provide: "A summary of the emissions reductions achieved throughout the State through implementation of the measures described in [40 CFR § 51.308(g)(1)." [128]

[125] *Id*.
[126] 40 CFR § 51.309(d)(9).
[127] As noted earlier, in the preamble to the January 10, 2017 Regional Haze Rule, EPA clarified that future periodic comprehensive SIP revisions and progress reports from the Section 309 states will be subject to the requirements of Section 308.
[128] 40 CFR § 51.308(g)(2).

5.4.1 SO_2 Milestone and Backstop Trading Program

Emission reductions attributable to this control measure were addressed in Section 5.3.1 – SO2 Milestone and Backstop Trading Program.

5.4.2 Best Available Retrofit Technology

Emission reductions attributable to this control measure were addressed in Section 5.3.2 – Best Available Retrofit Technology.

5.4.3 New Source Review Program

Emission reductions attributable to this control measure were addressed in Section 5.3.3 – New Source Review Program.

5.4.4 Mobile Sources

As discussed in Section 5.3.5 – Mobile Sources, Section 309 required an interim report to EPA and the public in the year 2018 on the status of regional and local control strategies for mobile sources. This Section presents data from WRAP consistent with a decline in mobile source emissions over the period 2003 to 2018.

Table 5-3 presents data from WRAP on emissions of coarse mass (particulate matter), fine soil (particulate matter), primary organic aerosols, and elemental carbon over the period 2000 to 2013 for the combined source categories of on-road mobile and off-road mobile. Table 5-4 presents data from WRAP on emissions of PM_{10} and $PM_{2.5}$ over the period 2014 to 2018 for the combined source categories of on-road mobile and non-road mobile. The differences in WRAP's emission inventory methodology for these periods are explained in Section 5.5 – Assessment of Visibility Conditions.

Table 5-3: New Mexico Mobile Source Emissions (On-Road Mobile + Off-Road Mobile) Over the Period 2000 to 2013 (Selected information from New Mexico Progress Report, 3/11/2014, Tables 3.27, 3.28, 3.29, and 3.30, and WRAP TSS Archived, IWDW-2011).

Year	Coarse Mass (Particulate Matter) (TPY)	Fine Soil (Particulate Matter) (TPY)	Primary Organic Aerosols (TPY)	Elemental Carbon (TPY)
2002 (Plan02d)	403 + 0 = 403	429 + 0 = 429	653 + 563 = 1,216	756 + 1,526 = 2,282
2008 (WEstJump2008)	2,994 + 41 = 3,035	258 + 25 = 283	1,506 + 349 = 1,855	2,999 + 457 = 3,456
2011 (IWDW-2011)	588.73 + 38.47 = 627	206.34 + 0 = 206	798.24 + 596.31 = 1,395	1256.67 + 405.96 = 1,662

Table 5-4: New Mexico Mobile Source Emissions (On-Road Mobile and Non-Road Mobile) Over the Period 2014 to 2018 (WRAP TSS - Emissions Data Analysis - Express Tools).

Year	PM_{10} (TPY)	$PM_{2.5}$ (TPY)
2014v2 Actual	3,361 + 674 = 4,035	2,171 + 640 = 2,811
Representative Baseline 2	3,361 + 626 = 3,987	2,171 + 597 = 2,768

5.4.5 Fire/Smoke Management

Emission reductions attributable to this control measure were addressed in Section 5.3.6 – Fire/Smoke Management.

5.4.6 Fugitive and Unpaved Road Dust

As discussed in Section 5.3.7 – Fugitive and Unpaved Road Dust, regional-scale dust emissions for the purpose of the Regional Haze Rule were determined to not be a significant contributor to visibility impairment within the 16 Colorado Plateau Class I Areas. Emission tables that include fugitive dust and unpaved road dust include:

- Table 5-16: New Mexico Coarse Mass Emissions by Category 2000 - 2013 (From Table 3.30, NM Progress Report, 3/11/14, p. 43 and WRAP TSS Archived)
- Table 5-17: New Mexico PM10 Emissions 2014 - 2018 (WRAP Technical Support System - Emissions Data Analysis - Express Tools – New Mexico PM10 emissions summary)
- Table 5-18: 5-19 New Mexico Fine Soil Emissions by Category 2000 - 2013 (From Table 3.29, NM Progress Report, 3/11/14, p. 42 and WRAP TSS Archived, IWDW-2011)
- Table 5-19: 5-20 New Mexico PM2.5 Emissions 2014 - 2018 (WRAP Technical Support System - Emissions Data Analysis - Express Tools - PM2.5 emissions summary)

NMED doesn't have a way of precisely attributing emission reductions to its program for fugitive dust from unpaved roads or stationary sources but is presenting this information for context.

5.4.7 Pollution Prevention - Renewable Energy Goals

As discussed in Section 5.3.8 – Pollution Prevention - Renewable Energy Goals, the State of New Mexico and Albuquerque-Bernalillo County have dramatically expanded their use of renewable energy in recent years. This Section presents data from WRAP on New Mexico's emissions of sulfur dioxide and nitrogen oxides from point sources over the period 2000 to 2018 to provide context regarding the state's ongoing transition to renewable energy sources. Table 5-5 presents data from WRAP on emissions of sulfur dioxide and nitrogen oxides over the period 2000 to 2013 for the Point source category.
Table 5-6 presents data from WRAP on emissions of sulfur dioxide and nitrogen oxides over the period 2014 to 2018 for the EGU Point, Oil & Gas Point, and Remaining Non-EGU Point source categories.

Table 5-5: New Mexico Point Source Emissions Over the Period 2000 to 2013 (From NM Progress Report, 3/11/2014: Table 3.23, p. 36; Table 3.24, p. 37 and WRAP TSS Archived, IWDW 2011).

Year	SO_2 (TPY)	NO_X (TPY)
2002 (Plan02d)	37,436	100,387
2008 (WestJump2008)	24,681	62,502
2011 (IWDW 2011)	19,943	48,085

Table 5-6: New Mexico Point Source Emissions (EGU Point + Oil & Gas Point + Remaining Non-EGU Point) Over the Period of Years 2014 Through 2018 (WRAP Technical Support System - Emissions Data Analysis - Express Tools).

Year	SO_2 (TPY)	NO_X (TPY)
2014v2 Actual	11,911 + 8,642 + 303 = 20,856	43,071 + 31,437 +3,720 = 78,228
Representative Baseline 2	3,665 + 8,641 +627 = 12,933	15,964 + 31,244 + 4,036 = 51,244

In 2021 and 2022, the two remaining New Mexico coal-fired power plants on non-Tribal land (Prewitt Escalante Generating Station and San Juan Generating Station) were decommissioned. In 2022 wind energy accounted for 35% of New Mexico's total in-state electricity generation, surpassing coal for the first time. At the beginning of 2023, the state ranked ninth in the nation in wind capacity with approximately 4,400 megawatts installed. [129] In 2022, renewable resources accounted for the largest share – about 42% - of New Mexico's in-state electricity generation from utility-scale (1 megawatt or larger) and small-scale (less than 1 megawatt) facilities combined. [130]

5.5 Assessment of Visibility Conditions

The progress report requirement is as follows: "For each mandatory Class I Federal area within the State, the State must assess the following visibility conditions and changes, with values for most impaired, least impaired and/or clearest days as applicable expressed in terms of 5-year averages of these annual values. The period for calculating current visibility conditions is the most recent 5-year period preceding the required date of the progress report for which data are available as of a date 6 months preceding the required date of the progress report." [131] The visibility conditions and changes to be assessed depend on when the progress report is due; progress reports due before January 31, 2025 must assess: "The current visibility conditions for the most impaired and least impaired days," [132]; "[t]he difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions," [133]; and "[t]he change in visibility impairment for the most impaired and least impaired days over the period since the period addressed in the most recent plan required under [40 CFR § 51.308(f)]." [134]

The material presented in Chapter 3 of this Regional Haze SIPr Rd 2 (2019-2028) addresses these progress report requirements. Table 5-7 provides a crosswalk comparison of these requirements and the tables in Chapter 3 where the information can be found.

[129] U.S. Energy Information Administration, New Mexico State Profile and Energy Estimates (last updated May 18, 2023), available at https://www.eia.gov/state/analysis.php?sid=NM, accessed September 28, 2023.
[130] *Id*.
[131] 40 CFR § 51.308(g)(3). Because the required date of this embedded progress report was July 31, 2021, the period for calculating current visibility conditions pursuant to 40 CFR § 51.308(g)(3) (2014-2018) is different than the period for calculating current visibility conditions pursuant to 40 CFR § 51.308(f)(1)(3) (2019-2023). Therefore, current visibility conditions for purposes of this embedded progress report are referred to as first period end point visibility conditions in Chapter 3 of this Regional Haze SIPr Rd 2 (2019-2028).
[132] 40 CFR § 51.308(g)(3)(i)(A).
[133] 40 CFR § 51.308(g)(3)(ii)(A).
[134] 40 CFR § 51.308(g)(3)(iii)(A).

Table 5-7: Embedded Progress Report Requirement to Chapter 3 Crosswalk.

Embedded Progress Report Requirement	Table No. – Column Heading
40 CFR § 51.308(g)(3)(i) The current visibility conditions for the most impaired and least impaired days.	Table 3-2: Visibility Conditions in New Mexico Class I Areas, 20% Most Impaired Days (in dv) and Table 3-3: Visibility Conditions in New Mexico Class I Areas, 20% Clearest Days (in dv) –First Period End Point Visibility Conditions (2014-2018 avg.)
40 CFR § 51.308(g)(3)(ii) The difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions.	Table 3-2 and Table 3-3 –Difference Between First Period End Point and Baseline Visibility Conditions
40 CFR § 51.308(g)(3)(iii) The change in visibility impairment for the most impaired and least impaired days over the period since the period addressed in the most recent plan required under [40 CFR § 51.308(f)].	Table 3-2 and Table 3-3 –Change from First Period Midpoint to First Period End Point Conditions

5.6 Analysis Tracking the Change in Emissions Contributing to Visibility Impairment from all Sources and Activities within the State over Time

The progress report must provide: "An analysis tracking the change over the period since the period addressed in the most recent plan required under [40 CRF § 51.308(f)] in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source or activity. With respect to all sources and activities, the analysis must extend at least through the most recent year for which the state has submitted emission inventory information to the Administrator in compliance with the triennial reporting requirements of Subpart A of [40 CFR Part 51] as of a date six months preceding the required date of the progress report. With respect to sources that report directly to a centralized emissions data system operated by the Administrator, the analysis must extend through the most recent year for which the Administrator has provided a State-level summary of such reported data or an internet-based tool by which the State may obtain such a summary as of a date six months preceding the required date of the progress report. The State is not required to backcast previously reported emissions to be consistent with more recent emissions estimation procedures, and may draw attention to actual or possible inconsistencies created by changes in estimation procedures." [135]

This Section presents an analysis of emissions of haze causing pollutants in New Mexico over time, by type of source or activity, using data provided by WRAP. EPA's April 2013 General Principles for the 5-Year Regional Haze Progress Reports for the Initial Regional Haze State Implementation Plans states that the reports should, ideally, present the most recent available data for emissions inventories performed five years apart, or as approximate as practicable given the methodology and availability of emissions

[135] 40 CFR § 51.308(g)(4).

inventories.[136] This Regional Haze SIPr Rd 2 (2019-2028) uses WRAP 2002 data to represent the 2000-2004 baseline period meteorological and emissions data, WRAP 2008 data to represent the 2005-2009 progress period meteorological and emissions data, WRAP 2011 data to represent the 2010-2013 progress period meteorological and emissions data, and WRAP 2014 data to represent the 2014-2018 progress period meteorological and emissions data.[137] Collectively, then, this Section will present WRAP data that is the most recent available and that covers the most recent period of approximately five years for which data is available in practical terms (2014 to 2018).

The WRAP data for 2002, 2008, and 2011 describe emissions inventories for the following pollutants: sulfur dioxide, nitrogen oxides, ammonia, volatile organic compounds, coarse particulate matter,[138] fine particulate matter,[139] primary organic aerosols,[140] and elemental carbon.[141] The WRAP data for 2014 describes emissions inventories for the following pollutants: sulfur dioxide, oxides of nitrogen, ammonia gas,[142] volatile organic compounds, PM_{10}, and $PM_{2.5}$. Changes in estimation procedures for the 2014 WRAP data mean that the pollutants coarse particulate matter, fine particulate matter, primary organic aerosols, and elemental carbon were not individually included. Instead, emissions inventories were included for PM_{10} and $PM_{2.5}$. Additionally, changes in estimation procedures for the 2014 WRAP data mean that the other pollutants - sulfur dioxide, nitrogen oxides, ammonia, and volatile organic compounds - are also not comparable to WRAP data for earlier periods. This Regional Haze SIPr Rd 2 (2019-2028) will not backcast previously reported emissions to be consistent with more recent emissions estimation procedures, nor will it speciate PM_{10}, and $PM_{2.5}$ into coarse particulate matter, fine particulate matter, primary organic aerosols, and elemental carbon.

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[136] EPA, General Principles for the 5-Year Regional Haze Progress Reports for the Initial Regional Haze State Implementation Plans, April 2013 ("EPA 2013 Guidance"), pp. 11-12.

[137] On the methodology for WRAP emissions inventories, see, for example, Zac Adelman and B.H. Baek, Three-State Air Quality Modeling Study Emissions Modeling Report: Simulation Years 2008 and 2011 (University of North Carolina at Chapel Hill, Institute for the Environment and ENVIRON Corporation), available by contacting the WRAP, http://wrapair2.org/; Cyndi Loomis, Zac Adelman, and Ralph Morris, Technical Memorandum No. 1: Point Source Emissions (March 15, 2013) (addressing the subject of "Point Source Emissions, including Electricity Generating Units (EGUs) and non EGUs, for the WestJumpAQMS 2008 Photochemical Modeling"), available at http://www.wrapair2.org/pdf/Memo1_PointSources_Mar15_2013final.pdf; Mobile Source Emissions (June 2011) (addressing the mobile source inventory scope and methodology) available at http://vista.cira.colostate.edu/docs/wrap/emissions/TSS%20Mobile%20Emissions%20June%202011.doc; Run Specification Sheet: Representative Baseline and 2028 On-The-Books CAMx Simulations (February 27, 2020) (addressing the inputs for developing domains that are representative of the 2014-2018 period) available at https://views.cira.colostate.edu/docs/iwdw/platformdocs/WAQS_2014/Run_Spec_WRAP_2014_Task2.3-RepBase_Task%204.4-2028_CAMx_v3.pdf.

[138] Coarse mass is reported by the IMPROVE network as the difference between PM_{10} and $PM_{2.5}$ mass measurements. Coarse mass is not separated by species in the same way that $PM_{2.5}$ is speciated, but these measurements are generally associated with crustal components. Similar to crustal $PM_{2.5}$, natural windblown dust is often the largest contributor to coarse mass. WRAP 2013 Summary Report, p. 6-223.

[139] Fine soil is reported here as the crustal or soil components of $PM_{2.5}$. WRAP 2013 Summary Report, p. 6-223.

[140] Primary organic aerosols represent organic aerosols that are emitted directly as particles, as opposed to gases. Wildfires in the west generally dominate primary organic aerosol emissions, and large wildfire events are generally sporadic and highly variable from year-to-year. WRAP 2013 Summary Report, p. 6-223.

[141] Large elemental carbon events are often associated with large particulate organic matter events during wildfires. Other sources include both on- and off-road diesel engines. WRAP 2013 Summary Report, p. 6-223.

[142] Despite a change in nomenclature from "ammonia" in the 2002, 2008, and 2011 WRAP emissions inventories to "ammonia gas" in the 2014 WRAP emission inventory, all of the emissions inventories are reporting on the pollutant "ammonia gas", with a chemical composition of NH_3.

Table 5-8 through Table 5-21, below, present the 2002, 2008, 2011, and 2014 WRAP data for the pollutants sulfur dioxide, nitrogen oxides, ammonia gas, volatile organic compounds, coarse particulate matter, PM_{10}, fine particulate matter, primary organic aerosols, elemental carbon, and $PM_{2.5}$ for all anthropogenic source categories. Collectively, this data covers the years 2000 through 2018. All values in the below tables are rounded to the nearest whole number, meaning that some results may show an emissions amount of zero.

5.6.1 Sulfur Dioxide Emissions 2000 – 2018

Table 5-8: New Mexico Sulfur Dioxide Emissions by Category 2000 - 2013 (From Table 3.23, NM Progress Report 3/11/2014, p. 36 and WRAP TSS Archived, IWDW-2011).

Source Category	Sulfur Dioxide Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump08c)	2011 (IWDW-2011)
Point	37,436	24,681	19,943
Area	5,115	347	897
On-Road Mobile	1,950	498	253
Off-Road Mobile	3,525	167	21
Area Oil and Gas	250	1,076	469
Fugitive and Road Dust	0	0	No results available
Anthropogenic Fire	78	622	41
Total Anthropogenic	48,354	27,392	21,624

Table 5-9: New Mexico Sulfur Dioxide Emissions by Category 2014 – 2018 (WRAP Technical Support System – Emissions Data Analysis – Express Tools – New Mexico SO2 Emissions Summary).

Source Category	Sulfur Dioxide Emissions (tons/year) 2014 (RepBase2)
EGU Point	3,665
Oil & Gas Point	8,641
Remaining Non-EGU Point	627
Oil & Gas Non-Point	14,484
Agriculture	0
Remaining Non-Point	946
Residential Wood Combustion	32
Fugitive Dust	0
On-Road Mobile	229
Marine Shipping	0
Rail	12
Non-Road Mobile	12
Prescribed Fire	554
Agricultural Fire	7
Total Anthropogenic	29,209

5.6.2 Nitrogen Oxides Emissions 2000 – 2018

Table 5-10: New Mexico Oxides of Nitrogen Emissions by Category 2000 - 2013 (From Table 3.24, NM Progress Report, 3/11/14, p. 37 and WRAP TSS Archived, IWDW-2011).

Source Category	Oxides of Nitrogen Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump08c)	2011 (IWDW-2011)
Point	100,387	62,502	48,085
Area	25,130	27,754	5,220
On-Road Mobile	67,835	72,074	57,191
Off-Road Mobile	45,311	8,566	7,539
Area Oil and Gas	56,210	35,838	49,899
Fugitive and Road Dust	0	0	116
Anthropogenic Fire	394	4,397	117
Total Anthropogenic	295,266	211,132	168,167

Table 5-11: New Mexico Nitrogen Oxides Emissions 2014 - 2018 (WRAP Technical Support System – Emissions Data Analysis – Express Tools) – New Mexico NOX Emissions Summary).

Source Category	Nitrogen Oxides Emissions (tons/year) 2014 (RepBase2)
EGU Point	15,964
Oil & Gas Point	31,244
Remaining Non-EGU Point	4,036
Oil & Gas Non-Point	50,064
Agriculture	0
Remaining Non-Point	7,649
Residential Wood Combustion	197
Fugitive Dust	0
On-Road Mobile	72,203
Marine Shipping	0
Rail	19,766
Non-Road Mobile	5,717
Prescribed Fire	574
Agricultural Fire	34
Total Anthropogenic	207,448

5.6.3 Ammonia Gas Emissions 2000 – 2018

Table 5-12: New Mexico Ammonia Emissions by Category 2000 - 2013 (From Table 3.25, NM Progress Report, 3/11/14, p. 38 and WRAP TSS Archived, IWDW-2001).

Source Category	Ammonia Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump08c)	2011 (IWDW-2011)
Point	75	274	272
Area	29,959	39,399	35,793
On-Road Mobile	2,132	1,090	957
Off-Road Mobile	26	10	10
Area Oil and Gas	0	0	0
Fugitive and Road Dust	0	0	0
Anthropogenic Fire	75	3,067	39
Total Anthropogenic	32,266	43,840	37,071

Table 5-13: New Mexico Ammonia Gas Emissions 2014 - 2018 (WRAP Technical Support System - Emissions Data Analysis - Express Tools – New Mexico NH3 emissions summary).

Source Category	Ammonia Gas Emissions (tons/year) 2014 (RepBase2)
EGU Point	322
Oil & Gas Point	0
Remaining Non-EGU Point	53
Oil & Gas Non-Point	0
Agriculture	17,869
Remaining Non-Point	500
Residential Wood Combustion	83
Fugitive Dust	0
On-Road Mobile	859
Marine Shipping	0
Rail	11
Non-Road Mobile	10
Prescribed Fire	1,231
Agricultural Fire	105
Total Anthropogenic	21,043

5.6.4 Volatile Organic Compound Emissions 2000 – 2018

Table 5-14: New Mexico Volatile Organic Compound Emissions by Category 2000 - 2013 (From Table 3.26, NM Progress Report, 3/11/14, p. 39 and WRAP TSS Archived, IWDW-2011).

Source Category	Volatile Organic Compound Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump08c)	2011 (IWDW-2011)
Point	17,574	9,855	7,193
Area	49,010	37,395	31,874
On-Road Mobile	38,768	29,629	20,332
Off-Road Mobile	13,850	11,383	10,260
Area Oil and Gas	224,268	174,990	143,828
Fugitive and Road Dust	0	0	0
Anthropogenic Fire	608	5,540	873
Total Anthropogenic	344,077	268,792	214,360

Table 5-15: New Mexico Volatile Organic Compound Emissions 2014 - 2018 (WRAP Technical Support System - Emissions Data Analysis - Express Tools – New Mexico VOC emissions summary).

Source Category	Volatile Organic Compound Emissions (tons/year) 2014 (RepBase2)
EGU Point	276
Oil & Gas Point	40,895
Remaining Non-EGU Point	2,009
Oil & Gas Non-Point	270,034
Agriculture	1,703
Remaining Non-Point	28,481
Residential Wood Combustion	1,841
Fugitive Dust	0
On-Road Mobile	24,816
Marine Shipping	0
Rail	1,016
Non-Road Mobile	5,433
Prescribed Fire	24,854
Agricultural Fire	60
Total Anthropogenic	401,418

5.6.5 Coarse Particulate Matter Emissions 2000 – 2013

Table 5-16: New Mexico Coarse Mass Emissions by Category 2000 - 2013 (From Table 3.30, NM Progress Report, 3/11/14, p. 43 and WRAP TSS Archived).

Source Category	Coarse Mass Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump08c)	2011 (IWDW-2011)
Point	2,286	1,168	821
Area	695	506	584
On-Road Mobile	403	2,994	589
Off-Road Mobile	0	41	38
Area Oil and Gas	0	12	2
Fugitive and Road Dust	62,607	504,915	828,626
Anthropogenic Fire	105	1,691	37
Total Anthropogenic	66,096	511,327	830,697

5.6.6 PM_{10} Emissions 2014 – 2018

Table 5-17: New Mexico PM10 Emissions 2014 - 2018 (WRAP Technical Support System - Emissions Data Analysis - Express Tools – New Mexico PM10 emissions summary).

Source Category	PM_{10} Emissions (tons/year) 2014 (RepBase2)
EGU Point	1,846
Oil & Gas Point	731
Remaining Non-EGU Point	2852
Oil & Gas Non-Point	1,607
Agriculture	0
Remaining Non-Point	3,670
Residential Wood Combustion	1,659
Fugitive Dust	312,720
On-Road Mobile	3,361
Marine Shipping	0
Rail	634
Non-Road Mobile	626
Prescribed Fire	8,506
Agricultural Fire	237
Total Anthropogenic	338,449

5.6.7 Fine Particulate Matter Emissions 2000 – 2013

Table 5-18: 5-19 New Mexico Fine Soil Emissions by Category 2000 - 2013 (From Table 3.29, NM Progress Report, 3/11/14, p. 42 and WRAP TSS Archived, IWDW-2011).

Source Category	Fine Soil Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump08c)	2011 (IWDW-2011)
Point	1,180	535	650
Area	2,821	1,485	122
On-Road Mobile	429	258	206
Off-Road Mobile	0	25	0
Area Oil and Gas	0	540	379
Fugitive and Road Dust	8,056	55,506	84,219
Anthropogenic Fire	87	3,239	0
Total Anthropogenic	12,573	61,587	85,576

5.6.8 $PM_{2.5}$ Emissions 2014 – 2018

Table 5-19: 5-20 New Mexico PM2.5 Emissions 2014 - 2018 (WRAP Technical Support System - Emissions Data Analysis - Express Tools - PM2.5 emissions summary).

Source Category	$PM_{2.5}$ Emissions (tons/year) 2014 (RepBase2)
EGU Point	1,273
Oil & Gas Point	731
Remaining Non-EGU Point	811
Oil & Gas Non-Point	1,606
Agriculture	0
Remaining Non-Point	2,877
Residential Wood Combustion	1,656
Fugitive Dust	34,417
On-Road Mobile	2,171
Marine Shipping	0
Rail	583
Non-Road Mobile	597
Prescribed Fire	7,495
Agricultural Fire	174
Total Anthropogenic	54,081

5.6.9 Primary Organic Aerosol Emissions 2000 – 2013

Table 5-20: New Mexico Primary Organic Aerosol Emissions 2000 - 2013 (From Table 3.27, NM Progress Report, 3/11/14, p. 40 and WRAP TSS Archived, IWDW-2011).

Source Category	Primary Organic Aerosol Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump08c)	2011 (IWDW-2011)
Point	978	277	507
Area	2,529	2,876	4,605
On-Road Mobile	653	1,506	798
Off-Road Mobile	563	349	596
Area Oil and Gas	0	31	217
Fugitive and Road Dust	474	3,819	11,206
Anthropogenic Fire	682	8,821	156
Total Anthropogenic	5,879	17,678	18,085

5.6.10 Elemental Carbon Emissions 2000 - 2013

Table 5-21: New Mexico Elemental Carbon Emissions by Category 2000 - 2013 (From Table 3.28, NM Progress Report, 3/11/14, p. 41 and WRAP TSS Archived, IWDW-2011).

Source Category	Elemental Carbon Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump08c)	2011 (IWDW-2011)
Point	13	71	337
Area	301	945	312
On-Road Mobile	756	2,999	1,257
Off-Road Mobile	1,526	457	406
Area Oil and Gas	0	0	125
Fugitive and Road Dust	34	74	118
Anthropogenic Fire	123	1,432	50
Total Anthropogenic	2,753	5,979	2,605

5.7 Assessment of Significant Changes in Anthropogenic Emissions from Within or Outside the State

The progress report must provide: "An assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred since the period addressed in the most recent plan required under [40 CFR § 51.308(f)] including whether or not these changes in anthropogenic emissions were anticipated in that most recent plan and whether they have limited or impeded progress in reducing pollutant emissions and improving visibility." [143]

5.7.1 Significant emissions reductions

5.7.1.1 SO_2 Milestone and Backstop Trading Program

Figure 5-1: 2003 - 2021 SO_2 Milestones and Emission Trends, shows that the regional SO_2 emissions have always met the milestone since the inception of the SO_2 Milestone and Backstop Trading Program. Table 5-1 further shows that participating states have held emissions below 60% of the milestone every year since 2014. Regional SO_2 emissions decreased from 92,553 tons in 2014 to 71,994 tons in 2018.

[143] 40 CFR § 51.308(g)(5).

5.7.1.2 Best Available Retrofit Technology

Emission reductions attributable to this control measure were discussed in Section 5.3.2: Best Available Retrofit Technology. A summary of first planning period estimated reductions is provided in Table 5-22. First planning period reductions were approximately 12,213 tons NO_X and 5,458 tons SO_2.

Table 5-22: Estimated reductions from BART at SJGS during first planning period.

Avg.	NO_X (tons)	SO_2 (tons)7
2008-2010	18,764	6,809
2018-2020	6,551	1,352
Total estimated reductions	12,213	5,458

5.7.1.3 Mobile Sources

Section 309 of the Regional Haze Rule required the First Period SIP to perform projections demonstrating a continuous decline in mobile source emissions [144] from 2003 to 2018. The data shown in Section 5.4.4 – Mobile Sources, confirmed this overall decline.

5.7.1.4 Pollution Prevention - Renewable Energy Goals

New Mexico Point Source emissions over the period of Years 2000-2013, and also from 2014-2018 have continued to decrease due, in part, to less reliance on fossil-fuel electricity generation over time.

5.7.2 Visibility trends from baseline period to 2018.

Chapter 3: Ambient Data Analysis, details all of the Regional Haze Rule requirements for visibility reporting at each of New Mexico's Class I Areas. From the 2000-2004 baseline period to the 2014-2018 current period addressed in this progress report, all network sites showed improving visibility and progress toward the Regional Haze Rule goals of reducing impacts on the most impaired days while not backtracking during the clearest days.

A progress report due before January 31, 2025, will further assess "[t]he current visibility conditions for the most impaired and least impaired days." [145]

[144] For the Regional Haze Rule definition of the term "continuous decline in mobile source emissions," *see* 40 CFR § 309(b)(6). The "continuous decline" is a decline in "the projected level of emissions" from mobile sources, forecast to occur in the future, after submittal of the First Period SIP.

[145] 40 CFR § 51.308(g)(3)(i)(A).

Chapter 6: Selection of Sources for Control Measures Analysis

The Regional Haze Rule requires that each state select emission sources for an analysis for potential new emission reduction measures that may be cost-effective to implement at the source.[146] The New Mexico Environment Department (NMED) conducted a two-tiered source selection process in coordination with the City of Albuquerque Environmental Health Department (EHD) on a statewide basis, excluding Tribal jurisdictions. The two-tiered source selection was based on guidance from the U.S. Environmental Protection Agency (EPA) and the Western Regional Air Partnership (WRAP). This chapter describes the methods and results which identified 24 facilities (tier one), and 133 individual pieces of equipment or treatment systems at the 23 facilities within NMED's jurisdiction with the potential to emit sulfur dioxide (SO_2) and/or nitrogen oxides (NO_X) in quantities above NMED's threshold for requiring an analysis of potential new emission reduction measures (tier two).

6.1 Regulatory Requirements

- A Regional Haze State Implementation Plan (SIP) revision must "evaluate and determine the emission reduction measures that are necessary to make reasonable progress" at Class I Areas.[147]
- The SIP revision's evaluation of emission reduction measures "should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources."[148]
- The SIP revision must include "a description of the criteria it used to determine which sources or groups of sources it evaluated" that would be subject to analysis for potential new control measures.[149]

6.2 Tier One Q/d Assessment for Selecting New Mexico Facilities for Control Measures Analysis

For tier one of the source selection process, NMED and EHD utilized the Q/d method, based on recommendations from WRAP. This method sums the quantity of aerosol precursor pollutants emitted by the facility (NO_X plus SO_2) and divides it by the distance from the facility to the nearest Class I Area. This provides a screening-level estimate of the potential for pollutants from the facility to impact the Class I Area. The WRAP recommendations (hereinafter, the "WRAP Source Selection Protocol") were completed in February 2019 and subsequently approved by consensus by WRAP's Regional Haze Planning Work Group.[150] A contractor, Ramboll, then developed a database application for facilitating regionally-consistent western U.S. Regional Haze source screening to assist in determining which emission sources might potentially require Reasonable Progress controls.

NMED and EHD agreed upon a single, statewide procedure for tier one of the source selection process, based on the WRAP Source Selection Protocol. The procedure involved calculating Q/d scores for all

[146] 40 CFR § 51.308(f)(2)(i).
[147] *Id*.
[148] *Id*.
[149] *Id*.
[150] WRAP Regional Haze Planning Workgroup - Control Measures Subcommittee, WRAP Reasonable Progress Source Identification and Analysis Protocol for Second 10-Year Regional Haze State Implementation Plans, February 27, 2019. WRAP Regional Haze Planning Work Group consensus is documented at https://www.wrapair2.org/TSC_Docket.aspx.

New Mexico Title V facilities [151] and comparing them to a threshold value to identify facilities requiring an analysis of potential new emission reduction measures. NMED and EHD followed these steps to complete the tier one screening:

1) NMED and EHD calculated "Q" in the Q/d equation as the sum of annual reported NO_X and SO_2 emissions by Title V facilities for 2016.
    a. NMED and EHD chose NO_X and SO_2 as the targeted pollutants because monitoring data indicates that aerosol species related to emissions of these two precursor pollutants (i.e., ammonium nitrate and ammonium sulfate) are the key drivers of anthropogenic visibility impairment at Class I Areas, as described in Chapter 3 of this Regional Haze SIPr Rd 2 (2019-2028). NMED and EHD chose not to include PM_{10} or other pollutants in the Q component of the Q/d calculation (which the WRAP Source Selection Protocol had identified as potential candidates for the calculation) because emissions of those pollutants from Title V facilities would have been a negligible contributor to the overall Q/d score, based on the information available to NMED.
    b. EHD and NMED chose the emissions reported by Title V facilities in 2016 as the basis for "Q" in the Q/d equation based in part on consultation with the Federal Land Managers, who used 2016 reported emissions as the basis for their own independent assessments of the potential visibility impacts of facilities. Additionally, EPA used reported 2016 emissions data as the basis for its own Regional Haze modeling of emissions and their potential visibility impacts. [152] Finally, NMED and EHD judged that 2016 reported emissions were sufficiently representative of recent emissions of NO_X and SO_2 for Title V facilities in New Mexico for purposes of assessing the potential visibility impacts of emissions from those facilities and selecting which would be subject to further analysis for potential control measures to reduce visibility impairing pollutants.
2) NMED and EHD calculated "d" in the Q/d equation as the distance in kilometers from the centroid of each facility to the boundary of the nearest Class I Area.
3) Using these "Q" and "d" values, NMED and EHD calculated Q/d scores for every Title V facility in the state, including in Albuquerque - Bernalillo County. NMED and EHD then identified a Q/d threshold necessary to capture 80% of the total NO_X and SO_2 emissions from all New Mexico Title V facilities combined. NMED and EHD chose this 80% threshold based on guidance in the WRAP Source Selection Protocol. The Protocol noted draft guidance from EPA [153] recommending an 80% threshold applied to emissions from all stationary sources. However, the Protocol recognized that emissions information for some types of stationary sources and area sources might be lacking in particular jurisdictions. In view of the lack of such information for minor stationary sources and area sources in NMED's and EHD's jurisdictions, [154] NMED and EHD decided to conduct a source selection process for major (i.e. Title V) sources only, applying an

[151] A Title V facility is a major source requiring a Title V operating permit pursuant to 20.2.70 NMAC.
[152] Technical documentation for EPA's modeling is available at https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling (last accessed September 29, 2023).
[153] EPA, Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, July 2016.
[154] NMED and EHD lack detailed emissions inventory data for minor stationary sources and area sources for the current Regional Haze planning period. Sufficient statewide data was not available to adequately assess the potential visibility impact of such sources at Class I Areas. Therefore, NMED and EHD chose not to evaluate minor stationary sources or area sources for potential new control measures in the current Regional Haze planning period. Minor stationary sources and area sources may be addressed in future planning periods or addressed through other rule makings.

80% threshold to the sum of emissions from these sources. EHD and NMED consulted with Federal Land Managers on this approach and received a favorable response.

6.3 Tier One Q/d Assessment Results – Selected Sources

NMED and EHD performed the state-level Q/d assessment in June 2019. As described above, the goal of the assessment was to identity the Title V facilities with the highest Q/d scores responsible for 80% of the total NO_X and SO_2 emissions from all New Mexico Title V facilities combined (i.e. adding the sum of those two pollutants together for all such facilities in the state), including facilities in Albuquerque - Bernalillo County. The assessment indicated that a Q/d threshold of 5.6 would achieve this goal. In all, 24 facilities had an individual Q/d score of 5.6 or greater. Therefore, NMED and EHD determined that those 24 facilities would each be required to perform a four-factor analysis (Chapter 7) to assess potential new emission reduction measures that may be cost-effective to implement. Several facilities selected to perform a four-factor analysis based on the Q/d assessment were nearest or in proximity to Class I Areas in neighboring states (Mesa Verde National Park, CO and Guadalupe Mountains National Park, TX).

Table 6-1 provides a list of all 134 Title V facilities included in NMED and EHD's tier one source screening and information related to the Q/d assessment for each facility, including: the name of the facility; the agency interest ("AI") number (for sources in NMED's jurisdiction); the Q/d score; the 2016 emissions information ("Q" term); the distance to the nearest Class I Area ("d" term); the name of the nearest Class I Area; and cumulative emissions, both in tons and as a percent of the total for all facilities combined, demonstrating that a Q/d threshold of 5.6 captures 80% of the total NO_X and SO_2 emissions from all New Mexico Title V facilities. Only one facility with a Q/d score above the threshold is located in Albuquerque - Bernalillo County under EHD's jurisdiction, the GCC Tijeras portland cement plant.

Table 6-1: Tier One Q/d Assessment Information for All New Mexico Title V Facilities. [155]

Facility	AI #[156]	2016 NO_X Emissions (tons)	2016 SO_2 Emissions (tons)	Q (tons)	Nearest Class I Area	d (km)	Q/d	Cumulative Emissions (tons)	Cumulative Emissions (%)
San Juan Generating Station	1421	14900.679	2923.104	17823.783	Mesa Verde NP	38.66	461.04	17823.78	35.46%
Bitter Lake Compressor Station	14	85.44	0	85.44	Salt Creek WA	1.7	50.26	17909.22	35.63%
Chaco Gas Plant	1148	2258.9	11.8	2270.7	Mesa Verde NP	80.24	28.30	20179.92	40.15%
Prewitt Escalante Generating Station	911	2441.41	898.58	3339.99	San Pedro Parks WA	127.91	26.11	23519.91	46.79%
Washington Ranch Storage Facility	220	74.884	1.294	76.178	Carlsbad Caverns NP	3.23	23.58	23596.09	46.94%
Jal No. 3 Gas Plant	569	345.97	1967.901	2313.871	Carlsbad Caverns NP	112.67	20.54	25909.96	51.55%
Monument Gas Plant	610	299.365	1953.118	2252.483	Carlsbad Caverns NP	110.39	20.40	28162.45	56.03%
Eunice Gas Plant	595	571.3	1433.5	2004.8	Carlsbad Caverns NP	108.38	18.50	30167.25	60.02%
GCC Rio Grande Portland Cement Plant	---	1084.396	28.997	1113.393	Bandelier WA	69.46	16.03	31280.64	62.23%
Pecos River Compressor Station	194	495.15	1.683	496.833	Carlsbad Caverns NP	35.71	13.91	31777.47	63.22%
Eunice Gas Processing Plant	609	1528.182	23.305	1551.487	Carlsbad Caverns NP	118.55	13.09	33328.96	66.31%
Saunders Gas Plant	612	663.794	416.696	1080.49	Salt Creek WA	91.6	11.80	34409.45	68.46%
Kutz Canyon Processing Plant	1158	716.4	2.7	719.1	Mesa Verde NP	69.54	10.34	35128.55	69.89%
Indian Basin Gas Plant	197	234.861	51.29	286.151	Carlsbad Caverns NP	30.17	9.48	35414.70	70.46%
San Juan Basin Gas Plant	1177	528.14	0.955	529.095	Mesa Verde NP	63.2	8.37	35943.79	71.51%
Blanco C&D Compressor Station	3552	491.4	3.4	494.8	Mesa Verde NP	63.37	7.81	36438.59	72.49%
Cunningham Station Power Plant	604	859.37	4.3	863.67	Carlsbad Caverns NP	111.79	7.73	37302.26	74.21%
Linam Ranch Gas Plant	589	572.64	322.183	894.823	Carlsbad Caverns NP	116.46	7.68	38197.09	75.99%
Denton Gas Plant	568	22.715	951.658	974.373	Salt Creek WA	126.89	7.68	39171.46	77.93%
Roswell Compressor Station No. 9	10	74.4	0.03	74.43	Salt Creek WA	9.75	7.63	39245.89	78.08%
South Carlsbad Compressor Station	218	152	1	153	Carlsbad Caverns NP	25.88	5.91	39398.89	78.38%
Mountainair Compressor Station No. 7	1569	436.59	0.06	436.65	Bosque del Apache WA	75.42	5.79	39835.54	79.25%
Artesia Gas Plant	199	340.776	24.962	365.738	Carlsbad Caverns NP	64.09	5.71	40201.28	79.98%
Blanco Compressor Station A	1147	356.53	0.12	356.65	Mesa Verde NP	63.35	5.63	40557.93	80.69%

[155] Q/d scores are based on 2016 emissions inventory data reported by the facilities to NMED and EHD, and distances to Class I Areas measured using GIS software.

[156] Facilities without an AI number are located in EHD's jurisdiction.

Facility	AI #[156]	2016 NO_X Emissions (tons)	2016 SO_2 Emissions (tons)	Q (tons)	Nearest Class I Area	d (km)	Q/d	Cumulative Emissions (tons)	Cumulative Emissions (%)
Empire Abo Gas Plant	191	77.13	271.12	348.25	Carlsbad Caverns NP	65.17	5.34	40906.18	81.38%
San Juan River Gas Plant	1252	124.424	108.03	232.454	Mesa Verde NP	44.71	5.20	41138.63	81.84%
Lordsburg Compressor Station	553	290.147	3.664	293.811	Chiricahua WA	67.51	4.35	41432.44	82.43%
Rio Grande Generating Station	122	617.304	2.338	619.642	Guadalupe Mtns NP	144.29	4.29	42052.09	83.66%
Red Bluff No. 3 Compressor Station	19	41.68	2.459	44.139	Salt Creek WA	10.52	4.20	42096.22	83.75%
Oil Center Booster Station	668	441.15	0.08	441.23	Carlsbad Caverns NP	111.54	3.96	42537.45	84.63%
Reeves Generating Station	---	225.028	0.601	225.629	Bandelier WA	62.66	3.60	42763.08	85.07%
Dogie Canyon Compressor Station	990	206.8	1.5	208.3	San Pedro Parks WA	60.86	3.42	42971.38	85.49%
Los Alamos National Laboratory	856	19.607	0.421	20.028	Bandelier WA	5.86	3.42	42991.41	85.53%
Golf Course Booster Station	592	375.2	0.523	375.723	Carlsbad Caverns NP	112.73	3.33	43367.13	86.28%
Artesia Refinery	198	198.81	37.56	236.37	Carlsbad Caverns NP	71.34	3.31	43603.50	86.75%
Maljamar Gas Plant	565	80.59	213.34	293.93	Carlsbad Caverns NP	89	3.30	43897.43	87.33%
Corona Compressor Station	849	170.36	0.1	170.46	White Mountain WA	54.75	3.11	44067.89	87.67%
La Jara Compressor Station	1010	205	2.3	207.3	Weminuche WA	67.06	3.09	44275.19	88.08%
Val Verde Treatment Plant	1182	148.9	42.6	191.5	Mesa Verde NP	63.9	3.00	44466.69	88.46%
Maddox Station	588	344.309	1.232	345.541	Carlsbad Caverns NP	115.38	2.99	44812.24	89.15%
Gallup Refinery	888	335.23	8.473	343.703	Petrified Forest NP	115.6	2.97	45155.94	89.83%
Milagro Gas Treating Plant	1277	168.1	3.2	171.3	Mesa Verde NP	63.98	2.68	45327.24	90.18%
Florida Compressor Station	868	282.717	4.383	287.1	Gila WA	108.05	2.66	45614.34	90.75%
Trunk L Compressor Station	1037	166.2	0	166.2	San Pedro Parks WA	67.07	2.48	45780.54	91.08%
Zia II Gas Plant	32800	160.65	18.856	179.506	Carlsbad Caverns NP	72.75	2.47	45960.04	91.43%
Monument Compressor Station	571	268.75	0.126	268.876	Carlsbad Caverns NP	110.25	2.44	46228.92	91.97%
El Cedro Compressor Station	1002	163.2	1.3	164.5	San Pedro Parks WA	73.57	2.24	46393.42	92.30%
MCA Tank Battery No2	624	9.87	184.03	193.9	Carlsbad Caverns NP	88.52	2.19	46587.32	92.68%
Thoreau Compressor Station #5	890	269.44	0.05	269.49	Petrified Forest NP	128.84	2.09	46856.81	93.22%
South Hat Mesa Booster Station	665	138.19	0.08	138.27	Carlsbad Caverns NP	74.61	1.85	46995.08	93.49%
Carracas CDP Compressor Station	1009	99.9	0	99.9	Weminuche WA	56.55	1.77	47094.98	93.69%
Chaparral Gas Plant	26896	106.8	3.7	110.5	Carlsbad Caverns NP	67.98	1.63	47205.48	93.91%

Facility	AI #[156]	2016 NO_X Emissions (tons)	2016 SO_2 Emissions (tons)	Q (tons)	Nearest Class I Area	d (km)	Q/d	Cumulative Emissions (tons)	Cumulative Emissions (%)
Middle Mesa Central Delivery Point	1272	91.2	0	91.2	Weminuche WA	56.63	1.61	47296.68	94.09%
BKU Compressor Station	29329	94.81	17.62	112.43	Carlsbad Caverns NP	75.05	1.50	47409.11	94.32%
31-6 CDP Compressor Station	1006	92.7	0	92.7	Weminuche WA	66.08	1.40	47501.81	94.50%
Luna Energy Center	878	112.027	5.593	117.62	Gila WA	84.43	1.39	47619.43	94.74%
32-8 No2 CDP Compressor Station	1236	70.5	0	70.5	Weminuche WA	51.69	1.36	47689.93	94.88%
Bluffview Power Plant	3535	67.81	0.203	68.013	Mesa Verde NP	53.24	1.28	47757.94	95.01%
East Vacuum Liquid Recovery and CO2 Plant	638	41.86	92.31	134.17	Carlsbad Caverns NP	108.82	1.23	47892.11	95.28%
Lobo Compressor Station	31692	91.9	9.25	101.15	Carlsbad Caverns NP	83.23	1.22	47993.26	95.48%
University of New Mexico	---	76.034	12.134	88.168	Bandelier WA	72.55	1.22	48081.43	95.65%
32-8 No. 3 Central Delivery Point	1168	67.9	0	67.9	Weminuche WA	56.51	1.20	48149.33	95.79%
32-9 Central Delivery Point	1226	66.1	0	66.1	Mesa Verde NP	55.55	1.19	48215.43	95.92%
Aztec Central Delivery Point	1276	53.9	0	53.9	Mesa Verde NP	45.33	1.19	48269.33	96.03%
Loco Hills Compressor Station	27765	57.03	30.74	87.77	Carlsbad Caverns NP	75.68	1.16	48357.10	96.20%
Thompson Compressor Station	1191	53.5	0.8	54.3	Mesa Verde NP	47.33	1.15	48411.40	96.31%
Chaco Compressor Station	1189	75.2	0.6	75.8	Mesa Verde NP	66.41	1.14	48487.20	96.46%
32-7 CDP Compressor Station	1221	60.8	0	60.8	Weminuche WA	54.02	1.13	48548.00	96.58%
Bloomfield Compressor Station	1192	70.131	1.321	71.452	Mesa Verde NP	64.44	1.11	48619.45	96.73%
Rosa No. 1 Compressor Station	1367	60.6	0	60.6	Weminuche WA	56.02	1.08	48680.05	96.85%
Hope Pump Station	52	87.67	0.009	87.679	Carlsbad Caverns NP	81.52	1.08	48767.73	97.02%
Pump Mesa Central Delivery Point	1273	59.2	0	59.2	Weminuche WA	58.57	1.01	48826.93	97.14%
Hobbs Generating Station	25726	98.926	17.911	116.837	Carlsbad Caverns NP	116.33	1.00	48943.77	97.37%
Roswell Compressor Station	6	13.893	0.019	13.912	Salt Creek WA	14.23	0.98	48957.68	97.40%
Eunice B&C Compressor Station	669	91.964	7.725	99.689	Carlsbad Caverns NP	108.38	0.92	49057.37	97.60%
Horse Canyon Central Delivery Point	1274	59.4	0	59.4	Mesa Verde NP	70.2	0.85	49116.77	97.71%
Trunk N Compressor Station	1303	40.3	0	40.3	Weminuche WA	48.24	0.84	49157.07	97.79%
Southside Water Reclamation Plant	---	60.689	5.04	65.729	Bandelier WA	80.79	0.81	49222.80	97.93%
Hart Canyon Compressor Station	1181	40.3	2	42.3	Mesa Verde NP	53.89	0.78	49265.10	98.01%
Coyote Compressor Station	31815	52.7	0.67	53.37	Carlsbad Caverns NP	68.86	0.78	49318.47	98.12%

Facility	AI #[156]	2016 NO_X Emissions (tons)	2016 SO_2 Emissions (tons)	Q (tons)	Nearest Class I Area	d (km)	Q/d	Cumulative Emissions (tons)	Cumulative Emissions (%)
Penasco Compressor Station	262	37.241	0.151	37.392	Carlsbad Caverns NP	56.87	0.66	49355.86	98.19%
29-6 #4 CDP Compressor Station	1013	50.6	0	50.6	Weminuche WA	79.48	0.64	49406.46	98.29%
Agave Dagger Draw Gas Plant	211	6.7	28.33	35.03	Carlsbad Caverns NP	57.18	0.61	49441.49	98.36%
New Mexico State University Campus	144	85.358	0.489	85.847	White Mountain WA	147.65	0.58	49527.34	98.53%
30-5 CDP Compressor Station	998	39.6	0	39.6	Weminuche WA	69.02	0.57	49566.94	98.61%
29-6 No. 2 Central Delivery Point	1007	39.5	0	39.5	Weminuche WA	75.34	0.52	49606.44	98.69%
North Crandell Compressor Station	1374	25	0	25	Mesa Verde NP	53.74	0.47	49631.44	98.74%
Cedar Hill Compressor Station	1331	20.4	1.2	21.6	Mesa Verde NP	48.52	0.45	49653.04	98.78%
Chino Mine	526	11.406	0.045	11.451	Gila WA	26.02	0.44	49664.49	98.80%
South Hobbs Unit RCF	33207	2.89	51.545	54.435	Carlsbad Caverns NP	126.15	0.43	49718.92	98.91%
Pump Canyon Compressor Station	1183	26.9	2.4	29.3	Weminuche WA	70.51	0.42	49748.22	98.97%
A-59 Compressor Station	1011	24.2	0	24.2	Weminuche WA	61.63	0.39	49772.42	99.02%
Frances Mesa Compressor Station	1038	23.9	2.3	26.2	Weminuche WA	70.72	0.37	49798.62	99.07%
Star Lake Compressor Station	905	18.82	0.89	19.71	San Pedro Parks WA	53.71	0.37	49818.33	99.11%
Portales Plant	1094	33.69	4.122	37.812	Salt Creek WA	110.82	0.34	49856.15	99.19%
Red Hills Gas Processing Plant	29885	26.7	0	26.7	Carlsbad Caverns NP	79.88	0.33	49882.85	99.24%
Huerfano Pump Station	1201	28.9	0.2	29.1	Mesa Verde NP	90.01	0.32	49911.95	99.30%
West Eunice Compressor Station	755	33.56	0.08	33.64	Carlsbad Caverns NP	112.47	0.30	49945.59	99.36%
Rio Bravo Generating Station	---	22.6	0.451	23.051	Bandelier WA	79.02	0.29	49968.64	99.41%
Afton Generating Station	164	40.314	1.407	41.721	Gila WA	152.93	0.27	50010.36	99.49%
Gobernador Compressor Station	989	15.4	2.4	17.8	Weminuche WA	71.36	0.25	50028.16	99.53%
Middle Mesa Compressor Station	1193	12.2	1.3	13.5	Weminuche WA	56.71	0.24	50041.66	99.55%
Intrepid - East Plant	208	14.5	0	14.5	Carlsbad Caverns NP	65.48	0.22	50056.16	99.58%
Pyramid Generating Station	558	14.5	0	14.5	Chiricahua WA	66.09	0.22	50070.66	99.61%
Lovington Refinery	622	22.321	3.12	25.441	Carlsbad Caverns NP	126.21	0.20	50096.10	99.66%
Holloman Air Force Base	942	11.096	0.893	11.989	White Mountain WA	63.68	0.19	50108.09	99.69%
Valencia Power Plant	1611	13.018	0.316	13.334	Bosque del Apache WA	82.2	0.16	50121.42	99.71%
3B-1 Turley Compressor Station	1153	9.6	1.3	10.9	Mesa Verde NP	69.59	0.16	50132.32	99.73%

Facility	AI #[156]	2016 NO_X Emissions (tons)	2016 SO_2 Emissions (tons)	Q (tons)	Nearest Class I Area	d (km)	Q/d	Cumulative Emissions (tons)	Cumulative Emissions (%)
Mosaic Potash Carlsbad Inc	196	6.43	0.586	7.016	Carlsbad Caverns NP	49.58	0.14	50139.34	99.75%
White Sands Missile Range	141	16.25	1.112	17.362	White Mountain WA	125.09	0.14	50156.70	99.78%
Espejo Compressor Station	1110	7.66	0.21	7.87	Bandelier WA	64.11	0.12	50164.57	99.80%
Lordsburg Generating Station	560	7.736	0.045	7.781	Chiricahua WA	64.42	0.12	50172.35	99.81%
Cannon Air Force Base	106	15.303	0.249	15.552	Salt Creek WA	129.28	0.12	50187.90	99.85%
West Flotation/North Compaction/HB Plant	29939	5.9	0	5.9	Carlsbad Caverns NP	52.41	0.11	50193.80	99.86%
Tyrone Mine	527	3.87	0.169	4.039	Gila WA	39.67	0.10	50197.84	99.87%
Lincoln Compressor Station	843	6.008	0.02	6.028	White Mountain WA	60.91	0.10	50203.87	99.88%
San Luis Pump Station	1109	3.6	0	3.6	San Pedro Parks WA	41.1	0.09	50207.47	99.88%
Afton Compressor Station	123	13.075	0.054	13.129	Gila WA	152.58	0.09	50220.60	99.91%
Kirtland Air Force Base	---	5.629	0.42	6.049	Bandelier WA	74.91	0.08	50226.65	99.92%
Cerro Colorado Landfill	---	5.858	1.316	7.174	Bandelier WA	90.59	0.08	50233.82	99.94%
Camino Real Landfill	167	6.63	1.78	8.41	Guadalupe Mtns NP	148.88	0.06	50242.23	99.95%
LCEC Power Plant	29433	6.095	0.149	6.244	Salt Creek WA	118.84	0.05	50248.48	99.97%
Compressor Station No167	667	4.918	0.014	4.932	Salt Creek WA	100.73	0.05	50253.41	99.98%
Rio Rancho Landfill	1128	1.73	0.88	2.61	Bandelier WA	54.51	0.05	50256.02	99.98%
Bloomfield Products Terminal	1156	2.53	0.2	2.73	Mesa Verde NP	66.19	0.04	50258.75	99.99%
Bluewater Compressor Station	882	2.415	0.014	2.429	Petrified Forest NP	128.76	0.02	50261.18	99.99%
Sandoval County Landfill	3752	0.687	0.045	0.732	Bandelier WA	50.43	0.01	50261.91	99.99%
La Luz Energy Center	32274	1	0.1	1.1	Bosque del Apache WA	82.75	0.01	50263.01	99.99%
Quay County Generating Plant	30775	2.023	0.005	2.028	Pecos WA	162.35	0.01	50265.04	100.00%
Caja Del Rio Landfill	1484	0.1	0.04	0.14	Bandelier WA	18.5	0.01	50265.18	100.00%
Decker Junction Central Delivery Point	1267	0.2	0	0.2	Mesa Verde NP	46.63	0.00	50265.38	100.00%
Belen Compressor Station	1590	0.221	0	0.221	Bosque del Apache WA	74.53	0.00	50265.60	100.00%
Caprock Compressor Station	572	0.014	0	0.014	Salt Creek WA	79.36	0.00	50265.61	100.00%
Espinosa Canyon Amine Plant	21709	0.01	0	0.01	Weminuche WA	67.19	0.00	50265.62	100.00%

1

Figure 6-1 shows the locations of all 24 Title V facilities selected to perform a four-factor analysis in relationship to New Mexico's and neighboring states' Class I Areas.

Figure 6-1: Location of Facilities Selected to Perform a Four-Factor Analysis Based on NMED and EHD's Q/d Assessment.

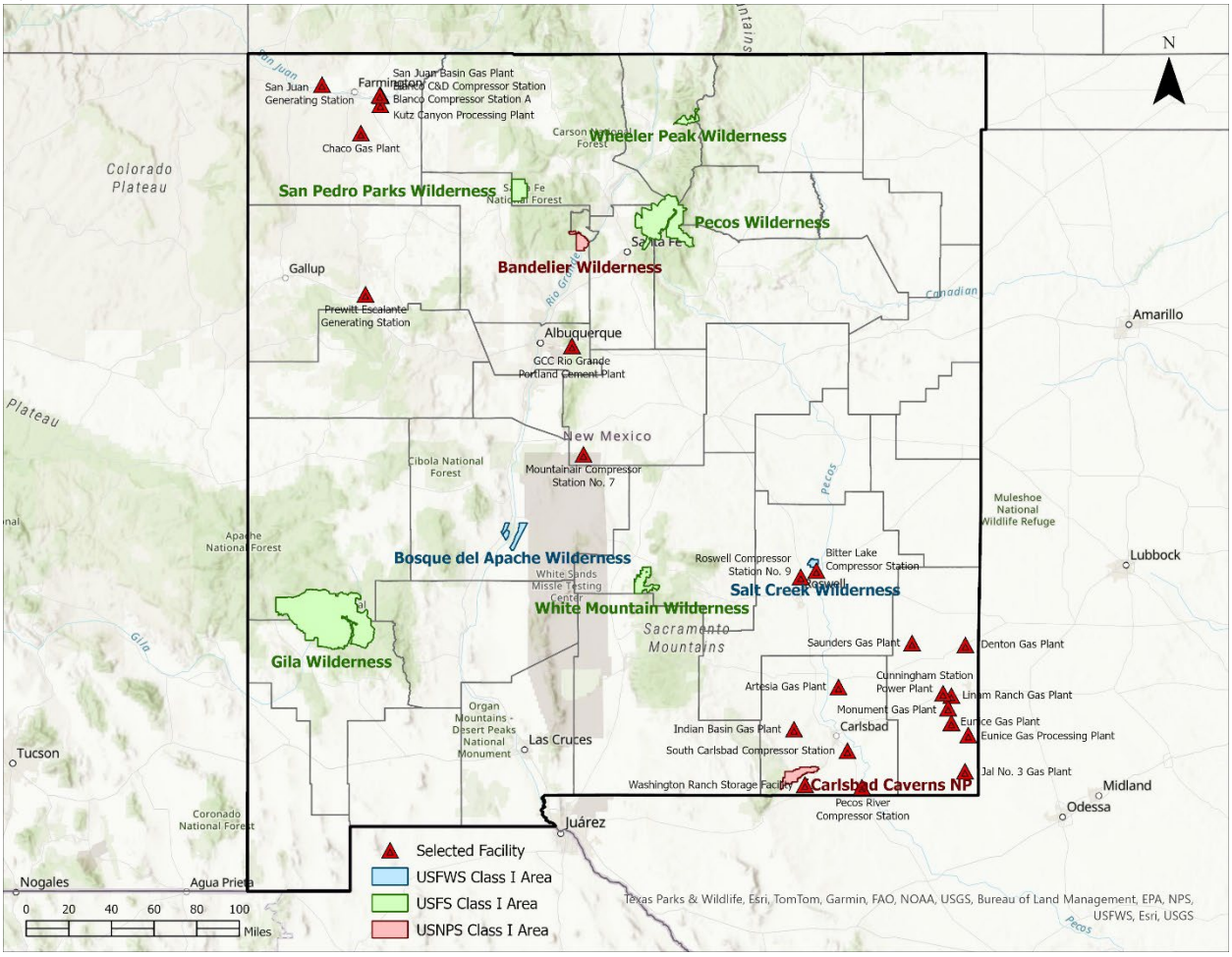


Table 6-2 shows the percentage of total statewide combined NO_X and SO_2 emissions from Title V facilities and the number of facilities responsible for that percentage of emissions at different Q/d thresholds. For example, a Q/d threshold of 10 or more would capture 13 Title V facilities responsible for 69.89% of the total NO_X and SO_2 emissions from all New Mexico Title V facilities combined. As noted above, NMED and EHD decided to use a Q/d threshold of 5.6, which captures 24 Title V facilities responsible for 80.69% of the total NO_X and SO_2 emissions from all New Mexico Title V facilities combined in 2016 .

Table 6-2: Statewide 2016 Title V Facility NOX and SO2 Emissions Captured by Various Q/d Thresholds.

Q/d Threshold	Number of Title V Sources Captured by Threshold	NO_X + SO_2 Emissions Captured by Threshold (tons per year)	% of Annual NO_X + SO_2 Emissions Captured by Threshold
10 or more	13	35,129	69.89%
9	14	35,415	70.46%
8	15	35,944	71.51%
7	20	39,246	78.08%
6	20	39,246	78.08%
5.7	23	40,201	79.98%
5.6	24	40,558	80.69%

6.4 Tier Two PTE Screen for Selecting Individual Source Equipment Requiring a Four-Factor Analysis

After selecting facilities to perform a four-factor analysis based on the Q/d assessment described above, NMED and EHD developed a secondary (tier two) screen to identify individual equipment for which an analysis of potential new control measures for NO_X and/or SO_2 would be required. Title V facilities are often complex and usually have numerous regulated sources of air pollutants. Each source typically has its own allowable emission limit, which is calculated using the maximum rated capacity of the source, accounting for any federally enforceable physical or operational limits (e.g., restricted operating hours) the source is subject to. Such limits are also known as potential to emit (PTE) and are listed in Title V operating permits and other types of air quality permits (e.g., construction permits).

In order to focus on the most significant sources of NO_X and SO_2 at the selected facilities and expend their limited resources where they would have the greatest impact in terms of reducing anthropogenic visibility impairment at Class I Areas, NMED and EHD determined that a four-factor analysis would only be required on individual equipment with a PTE greater than ten pounds per hour of NO_X or SO_2 pursuant to the facility's latest Title V operating permit. NMED further determined that equipment exempt under 20.2.72 NMAC – Construction Permits (e.g., emergency generators subject to stringent operating restrictions) or insignificant under 20.2.70 NMAC – Operating Permits, as well as equipment that emits less than five tons per year of NO_X or SO_2, did not need to undergo an analysis. At all but a few selected facilities within NMED's jurisdiction, equipment meeting these screening criteria accounts, in the aggregate, for over 90 percent – and in some cases 100 percent – of the facility's total allowable NO_X and/or SO_2 emissions.

NMED applied a tier two Potential to Emit (PTE) screen to the 23 facilities selected to perform a four-factor analysis in its jurisdiction after completing its Q/d assessment in June 2019. The screen identified 133 individual pieces of equipment or treatment systems with the potential to emit SO_2 and/or NO_X in quantities above NMED's 10 pounds per hour threshold and therefore requiring a four-factor analysis for NO_X, SO_2, or both. Table 6-3 summarizes all equipment requiring a four-factor analysis at the 23 facilities selected by NMED. Chapter 7 of this Regional Haze SIPr Rd 2 (2019-2028) describes these analyses for all screened equipment at the 23 facilities within NMED's jurisdiction.

Table 6-3: Tally of Individual Equipment Category Sources Selected in Tier-2 Screening.

Facility	Two Stoke Lean Burn Engines (2SLB RICE)	Four Stroke Lean Burn Engines (4SLB RICE)	Four Stroke Rich Burn Engines (4SRB RICE)	Combustion Turbines	Boilers	Amine Treatment Systems	**Total equipment at each facility**
Denton Gas Plant	-	-	-	-	-	1	**1**
Artesia Gas Plant	-	-	-	-	-	1	**1**
Eunice Gas Plant [1]	-	-	-	5	-	1	**6**
Linam Ranch Gas Plant	6	-	-	4	-	1	**11**
Blanco Compressor Station A	14	-	-	-	-	-	**14**
Pecos River Compressor Station	-	-	-	3	-	-	**3**
Washington Ranch Storage Facility	2	-	-	-	-	-	**2**
Blanco C&D Compressor Station	-	-	-	3	-	-	**3**
Chaco Gas Plant	3	-	-	5	-	1	**9**
South Carlsbad Compressor Station	-	-	-	2	-	-	**2**
Jal #3 Gas Plant	2	-	-	-	-	1	**3**
Mountainair Compressor Station No. 7	-	3	2	-	-	-	**5**
Roswell Compressor Station No. 9	-	2	-	-	-	-	**2**
Kutz Canyon Processing Plant	-	-	3	8	-	-	**11**
San Juan Basin Gas Plant	-	-	-	7	-	1	**8**
Bitter Lake Compressor Station	2	-	-	-	-	-	**2**
Indian Basin Gas Plant	-	-	-	3	-	1	**4**
San Juan Generating Station	-	-	-	-	2	-	**2**
Eunice Gas Processing Plant	13	-	-	-	2	1	**16**
Monument Gas Plant	7	-	-	-	-	1	**8**
Saunders Gas Plant	9	-	3	-	-	1	**13**
Prewitt Escalante Generating Station	-	-	-	-	3	-	**3**
Cunningham Station Power Plant	-	-	-	2	2	-	**4**
Overall Tally	58	5	8	42	9	11	**133**

Chapter 7: Four-Factor Analyses and Reasonable Progress Control Measures Determinations

This chapter provides the Regional Haze Rule requirements for determining what control measures are necessary to make reasonable progress and describes how NMED developed the cost/ton threshold used to identify cost-effective controls and how NMED determined which cost-effective controls are necessary to make reasonable progress. This chapter also summarizes the results of NMED's four-factor analyses and control measures determinations for selected sources.

7.1 Regulatory Requirements

The Regional Haze Rule requires that this Regional Haze SIPr Rd 2 (2019-2028) contain an evaluation of the emission reduction measures that are necessary to make reasonable progress toward natural visibility conditions in Class I Areas in New Mexico, as well as in Class I Areas outside New Mexico that may be affected by emissions from New Mexico.[157] In determining which measures are necessary to make reasonable progress, states are required to consider four statutory factors, including "the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment."[158] Hence, these evaluations are commonly referred to as four-factor analyses.

7.2 Controls Evaluated

NMED first identified all commercially available NO_X and/or SO_2 controls for the various types of units selected for analysis via the two-tiered screening process described in Chapter 6. These types of units include two-stroke lean burn engines (2SLB RICE), four-stroke lean burn engines (4SLB RICE), four-stroke rich burn engines (4SRB RICE), combustion turbines (CT), industrial and utility boilers, and amine treatment systems (ATS). NMED then determined which of the commercially available controls are technically feasible, as a four-factor analysis is only required for technically feasible controls. Based on the information available, NMED determined that the following controls are technically feasible for the units selected for analysis:[159]

- 2SLB RICE: Low-Emission Combustion (LEC), replacement and electrification.
- 4SLB RICE: LEC, Selective Catalytic Reduction (SCR), replacement, and electrification.
- 4SRB RICE: LEC, Non-Selective Catalytic Reduction (NSCR), replacement and electrification.
- CT: Dry Low NO_X Combustion (DLN), SCR, replacement, and electrification. For certain turbine models, water or steam injection (WSI) is also technically feasible.
- Boilers: Low NO_X Burners (LNB), Flue Gas Recirculation (FGR), SCR, and replacement.
- ATS: Flaring, sulfur recovery unit (SRU), thermal oxidizer (TO), and acid gas injection (AGI) well.

NMED received feedback from some of the facilities selected for analysis in the second planning period suggesting that replacement and electrification are outside the scope of the Regional Haze program and

[157] 40 CFR 305(f)(2)(i).

[158] *Id*.

[159] Good combustion practices (GCP) and retirement were also identified as technically feasible controls for all types of units selected for analysis. However, all screened facilities utilize GCP already based on their compliance with various provisions of their Title V permits, and with just a few exceptions, all facilities indicated that they do not plan to permanently retire any of the units selected for analysis. Therefore, NMED generally excluded these control options from its analyses.

that states are limited to considering new add-on controls (i.e., retrofits) and upgrades to existing controls under the program. NMED discussed this issue with EPA Region 6 staff, and they indicated that replacement and electrification are not outside the scope of the program given the prodigious flexibility afforded to states by the Regional Haze Rule. In addition, NMED's Office of General Counsel performed its own analysis and determined that NMED has the legal authority under the Regional Haze program to require replacement and electrification. Therefore, NMED evaluated the cost effectiveness of these options for those sources for which they are technically feasible, along with that of retrofits and upgrades to existing controls.

7.3 Cost of Compliance

After determining which controls are technically feasible, NMED performed a four-factor analysis of all technically feasible controls for all units that met the tier two screening criteria described in Chapter 6. To characterize the cost of compliance, which was the predominant factor in NMED's decision-making regarding control measures, NMED calculated the cost effectiveness of each control, expressed in terms of cost per ton of emissions reduced. NMED utilized source-specific cost estimates provided by the facilities in its calculations whenever possible. In cases where facilities failed to provide source-specific cost estimates or NMED found estimates provided by facilities to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including -four-factor analyses developed for similar facilities in New Mexico and other states, to estimate costs.

Consistent with EPA guidance, [160] NMED chose to apply a cost effectiveness threshold value (CETV) to remove control measures deemed not cost-effective from further consideration. To determine its CETV, which represents the cost effectiveness value above which further incremental reductions in NO_X emissions are insufficient to justify more expensive controls, NMED catalogued the available controls, identified the most effective controls available at potential CETVs ranging from $1,000/ton to $20,000/ton, and then determined the estimated total and incremental NO_X reductions provided by the most effective controls at each potential CETV. NMED then binned the incremental NO_X reductions and performed a segmented linear regression on a plot of the estimated total NO_X reductions with breakpoints at the bin edges. The results are shown in Figure 7-1. The binning and associated regression analysis showed that incremental NO_X reductions were significant up to $10,000/ton and then decreased by approximately 50%, with an even larger decrease at $14,000/ton. This led NMED to identify $10,000/ton as its CETV.

After completing its initial analysis, NMED decided to categorically exclude electrification from further consideration, for reasons discussed in Section 7.4.2. NMED also revised some of its underlying cost estimates due to ongoing data quality assurance efforts and comments from stakeholders. Therefore, NMED removed electrification from its catalogue of available controls and updated its CETV analysis using the revised cost estimates. The results are shown in Figure 7-2. The binning and associated regression analysis for the updated analysis continue to show that incremental NO_X reductions are significant up to $10,000/ton then decrease by approximately 50%, with an even larger decrease at $13,000/ton (versus $14,000/ton in the original analysis).

[160] EPA Regional Haze SIP Guidance, p. 38.

Figure 7-1. Estimated total NOX reductions at increasing CETVs with segmented linear regression (initial analysis).

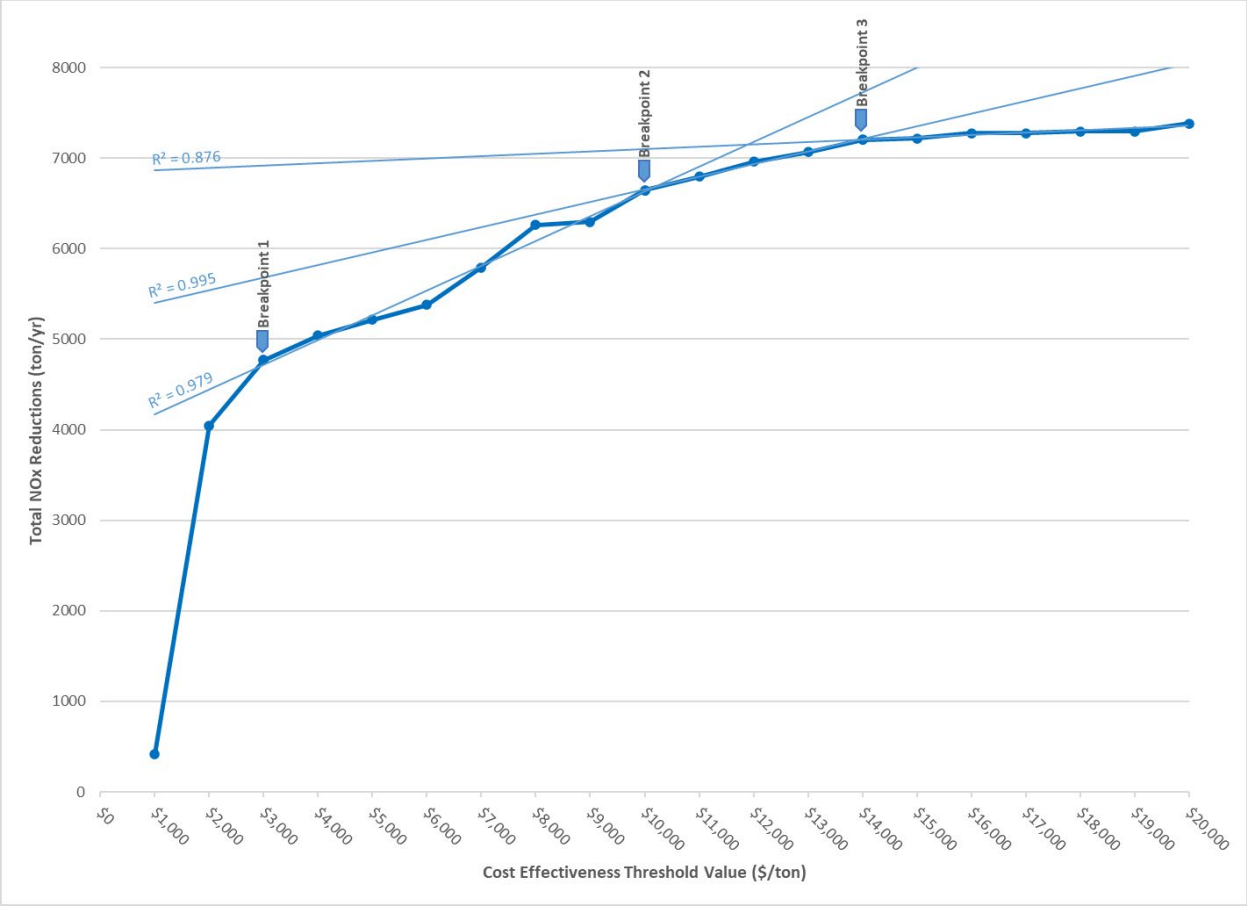
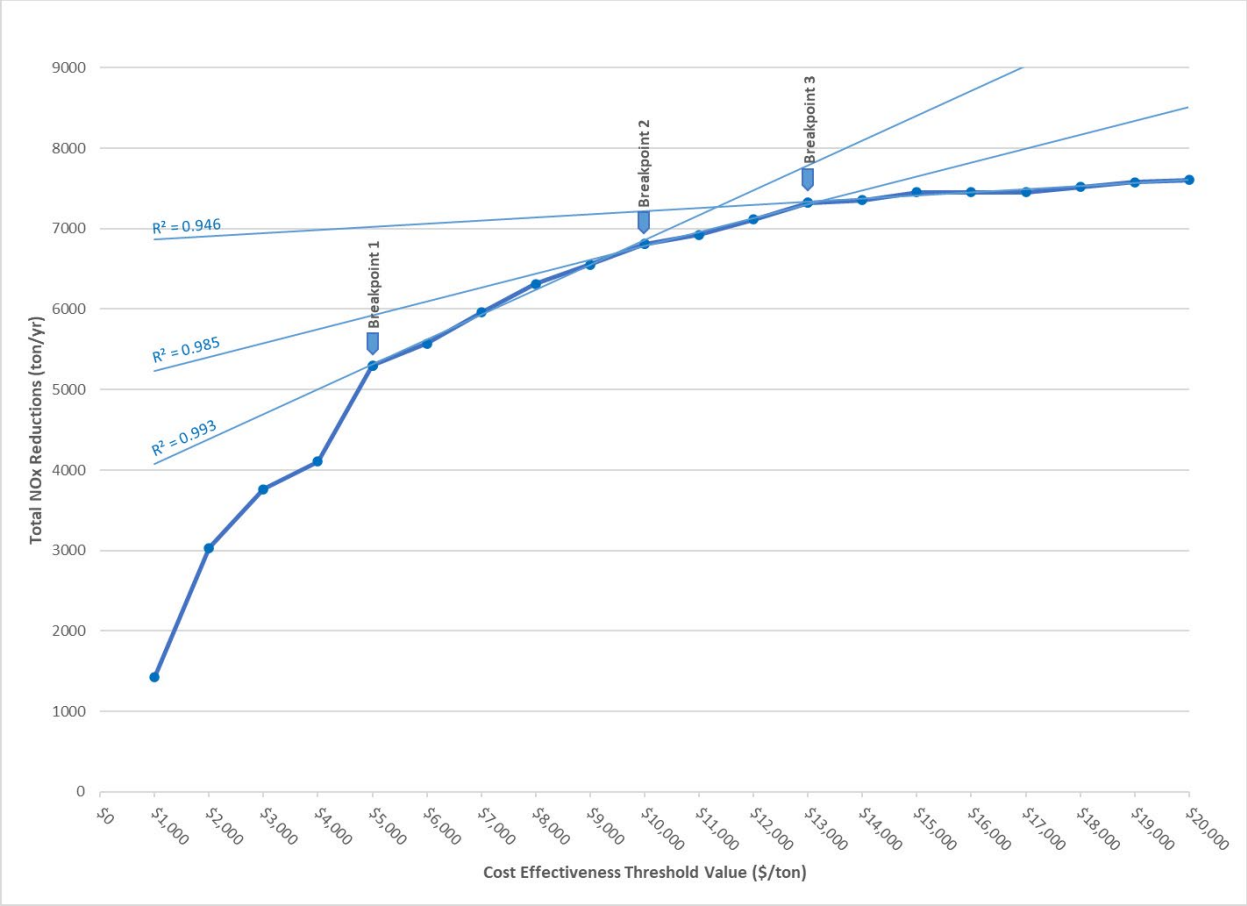


Figure 7-2. Estimated total NOX reductions at increasing CETVs with segmented linear regression (updated analysis).



Due to the similarity of the revised estimated total NO_X reductions plot to the original, and the fact that the breakpoints are nearly identical on both plots with the key breakpoint occurring at $10,000/ton, NMED decided to retain $10,000/ton as its CETV. NMED surveyed other states' second period SIPs, and $10,000/ton is within the range of CETVs proposed by other states. As such, NMED believes $10,000/ton strikes a reasonable balance, providing significant emissions reductions and, by extension, visibility benefits without subjecting New Mexico sources to more costly and burdensome requirements than sources in other states.

7.4 Selection of Controls

7.4.1 Baseline decision-making approach

Cost effectiveness was the predominant factor in NMED's decision-making regarding necessary control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance, whereas compliance time, which is more important at the next step, i.e., determining reasonable deadlines for installing selected controls, was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not directly consider the visibility benefits of potential control measures when making its control determinations. EPA has

consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making control determinations. [161] NMED's approach is based on the assumption that substantial reductions in emissions of NO_X and SO_2 will translate into visibility benefits.

As discussed in Section 7.3, NMED identified $10,000/ton as the threshold value above which further incremental reductions in NO_X emissions are insufficient to justify more expensive controls. With one notable exception, discussed in Section 7.4.2, for emissions units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For emissions units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent control (i.e., the one providing the greatest estimated NO_X reductions) is necessary to make reasonable progress.

7.4.2 Exceptions

The sole exception to NMED's baseline decision-making approach involves electrification. Electrification entails replacing a natural gas-fired compressor driver (reciprocating engine or combustion turbine) with a zero-emitting electric motor drive (EMD), making it one of the most effective controls available. NMED developed numerous cost estimates for electrification, and with only a few exceptions, the cost effectiveness of electrification far exceeded NMED's CETV of $10,000/ton. For the few facilities for which the cost effectiveness was below the CETV, NMED had concerns about the reliability of the estimates. Electrification generally involves significant ancillary costs associated with upgrading electrical infrastructure to handle the increased load associated with EMDs. These upgrades can include upgrading or building new electrical substations and upgrading or installing new high voltage transmission lines to the facility. Detailed engineering studies, which are rarely available, are generally needed to accurately assess specific infrastructure needs and reliably estimate costs. Further complicating matters is uncertainty regarding the willingness and ability of local utility providers to service the increased load associated with EMDs, even assuming all of the infrastructure upgrades necessary to support electrification are completed, and how the costs for any new energy resources that must be acquired would be apportioned. Based on these and other uncertainties, NMED determined that electrification, despite its obvious benefits, should be categorically excluded from selection as the reasonable progress control as there are simply too many unknowns to reliably estimate the costs involved and/or determine whether it is truly feasible.

[161] EPA, Responses to Comments on Protection of Visibility: Amendments to Requirements for State Plans (December 2016) at 186 ("While the CAA lists the four reasonable progress factors, it is silent as to whether states or the EPA may consider other, additional factors. This final rule neither requires nor prohibits states from considering visibility when making reasonable progress determinations."). *See also* EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) at 28 ("Section 169A(g)(1) of the CAA lists four factors that must be taken into consideration in determining reasonable progress … The visibility benefit of an emission reduction measure is not listed as a required factor, but neither the CAA nor the Regional Haze Rule prohibits a state from considering visibility benefits when it determines what emission control measures are required for a source to make reasonable progress at a Class I area. Therefore, a state **may** consider the visibility benefits of potential control measures when determining what is necessary to make reasonable progress.")(emphasis added).

7.4.3 Implementation of controls

NMED's reasonable progress control measures determinations are not prescriptive. That is, a determination by NMED that a particular control is necessary for reasonable progress does not mean the source must install that control. Instead, NMED is imposing new emissions limitations in this Regional Haze SIPr Rd 2 (2019-2028) commensurate with controls deemed necessary for reasonable progress and leaving it up to facilities to determine how to comply. This means a facility could elect to install a different control than the one NMED determined is necessary for reasonable progress, as long as the alternative is capable of meeting the new limit. This approach is intended to give facilities the flexibility to consider factors beyond the four statutory factors considered by NMED when deciding how to comply with Regional Haze requirements. For example, if NMED determines that reasonable progress requires the installation of LEC on a 2SLB RICE, and the engine has already been in service for decades and is becoming more difficult and costly to maintain, the facility could opt to replace it with a new, lower-emitting engine instead of retrofitting it with LEC – even if NMED rejected replacement on cost effectiveness grounds – because the facility believes that the enhanced reliability and extended service life a new engine outweighs the additional upfront cost and thus represents a better business decision.

7.5 Four-Factor Analyses and Reasonable Progress Control Measures Determinations

NMED's four-factor analyses and reasonable progress control measures determinations for the 23 facilities selected for analysis in the second planning period are described in detail in Appendix C and summarized below. Supporting documentation for NMED's cost estimates and cost effectiveness determinations is provided in Appendix D.

7.5.1 Davis Gas Processing, Inc. – Denton Gas Plant

7.5.1.1 Facility Description

Denton Gas Plant (DGP) is a former natural gas processing facility previously located 11 miles east of Lovington in Lea County, New Mexico at latitude 33^{o} 2' 38", longitude -103^{o} 10' 15". It was owned and operated by Davis Gas Processing, Inc. (Davis), and was one of 23 facilities selected for an analysis of potential control measures when NMED performed the source screening described in Chapter 6 in 2019. However, Davis subsequently shut down DGP on December 1, 2022, and submitted an administrative permit revision closing NSR Permit No. 0065-M8 and voluntarily discontinuing Title V Operating Permit No. P079-R3 on February 2, 2022. Davis demolished the facility shortly thereafter.

7.5.1.2 Summary of Four-Factor Analysis

NMED originally selected DGP's ATS for an analysis of potential control measures for SO_2 in the second planning period due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). However, because DGP has since been shut down and demolished, NMED did not perform a FFA of potential control measures for the ATS. There is no more effective control for an ATS than retirement, which reduces emissions by 100 percent. Therefore, NMED has determined that DGP's ATS is already effectively controlled by virtue of its retirement, and that a FFA could only result in the conclusion that no further controls are necessary to make reasonable progress.

7.5.1.3 Control Measures Determination

Because it is already effectively controlled, NMED determined that reasonable progress does not require new controls on the ATS at DGP.

7.5.2 DCP Operating Company, LP – Artesia Gas Plant

7.5.2.1 Facility Description

Artesia Gas Plant (AGP) is a natural gas processing facility located 13 miles east-southeast of Artesia in Eddy County, New Mexico at latitude 32° 45' 18", longitude -104° 12' 36". It is owned and operated by DCP Operating Company, LP (DCP), and currently operates under Title V Operating Permit No. P095-R4, which expires on March 8, 2028. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 39.8 miles.

The function of the facility is to process natural gas, including condensate removal, H2S and CO2 removal with an amine unit, separation of natural gas liquids through the cryogenic plant, and inlet and residue compression. The facility is authorized for continuous operation, and its total potential to emit is 476.0 tons per year of NO_X and 389.3 tons per year of SO_2.

7.5.2.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for the ATS at AGP due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). NMED's analysis of the four statutory factors is discussed in detail in Section C.5.2.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
ATS	Redundant Compression	$16,000	2-3	20	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

7.5.2.3 Control Measures Determination

Based on its analysis of the four statutory factors, the cost effectiveness threshold described in Section 7.3, and the control selection criteria described in Section 7.4, NMED determined that there are no cost-effective controls for the ATS at AGP. Therefore, NMED determined that reasonable progress does not require new controls for the ATS.

7.5.3 DCP Operating Company LP – Eunice Gas Plant

7.5.3.1 Facility Description

Eunice Gas Plant (EGP) is a former natural gas processing facility located 7 miles northwest of Eunice in Lea County, New Mexico at latitude 32° 30' 31", longitude -103° 17' 08". It was owned and operated by DCP and was one of 23 facilities selected for an analysis of potential control measures when NMED performed the source screening described in Chapter 6 in 2019. However, DCP subsequently entered into a Settlement Agreement and Stipulated Compliance Order (SASFCO) with NMED on September 10, 2021, which required DCP to permanently cease operations at EGP within 60 days. As required by the SASFCO, DCP shut down EGP on June 6, 2021, and submitted an administrative permit revision closing NSR Permit No. 0044-M11R1 and voluntarily discontinuing Title V Operating Permit No. P086-R2 on November 3, 2021.

7.5.3.2 Summary of Four-Factor Analysis

NMED originally selected EGP's five combustion turbines for an analysis of potential control measures for NO_X in the second planning period. NMED also elected to evaluate the ATS at EGP for potential control measures for SO_2 due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). However, because EGP has since been shut down and decommissioned pursuant to the SASFCO, NMED did not perform a FFA of potential control measures for any of these units. There is no more effective control for a turbine or ATS than retirement, which reduces emissions by 100 percent. Therefore, NMED has determined that EGP's turbines and ATS are already effectively controlled by virtue of their retirement, and that a FFA could only result in the conclusion that no further controls are necessary to make reasonable progress.

7.5.3.3 Control Measures Determination

Because they are already effectively controlled, NMED determined that reasonable progress does not require new controls on the turbines or ATS at EGP.

7.5.4 DCP Operating Company, LP – Linam Ranch Gas Plant

7.5.4.1 Facility Description

Linam Ranch Gas Plant (LRGP) is a natural gas processing facility located 7 miles west of Hobbs in Lea County, New Mexico at latitude 32° 41' 43", longitude -103° 17' 07". It is owned and operated by DCP and currently operates under Title V Operating Permit No. P094-R3, which expires on December 18, 2025. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 72.7 miles.

The function of the facility is to remove hydrogen sulfide, water and carbon dioxide from field natural gas and separate natural gas liquids (NGL) from the field natural gas stream. The facility is authorized for continuous operation, and its total potential to emit is 973.5 tons per year of NO_X and 87.1 tons per year of SO_2.

7.5.4.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for NO_X for six (6) 2SLB RICE and four (4) combustion turbines at LRGP that met the tier two screening criteria described in Chapter 6. NMED's analysis of the four statutory factors for these units is discussed in detail in Section C.5.4.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
6	LEC	$15,000	2-3	20	None
	Replacement	$22,000	3-4	30	None
	Electrification	$35,000	4-6	25	None
7	LEC	$13,000	2-3	20	None
	Replacement	$20,000	3-4	30	None
	Electrification	$31,000	4-6	25	None
8	LEC	$15,000	2-3	20	None
	Replacement	$15,000	3-4	30	None
	Electrification	$24,000	4-6	25	None
9	LEC	$5,000	2-3	20	None
	Replacement	$15,000	3-4	30	None
	Electrification	$24,000	4-6	25	None
10	LEC	$14,000	2-3	20	None
	Replacement	$14,000	3-4	30	None
	Electrification	$24,000	4-6	25	None
11	LEC	$24,000	2-3	20	None
	Replacement	$23,000	3-4	30	None
	Electrification	$36,000	4-6	25	None
29	SCR	$124,000	3-4	20	None
	Replacement	-$315,000 [(2)]	3-4	30	None
	Electrification	$1,106,000	4-6	25	None
30	SCR	$70,000	3-4	20	None
	Replacement	-$1,373,000 [(2)]	3-4	30	None
	Electrification	$604,000	4-6	25	None
31	SCR	$27,000	3-4	20	None
	Replacement	$501,000	3-4	30	None
	Electrification	$188,000	4-6	25	None
32B	SCR	$30,000	3-4	20	None
	Replacement	N/A [(3)]	3-4	30	None
	Electrification	$181,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.
[(2)] Negative cost effectiveness is an artifact of NMED's method for calculating this value and does not accurately represent the cost effectiveness of the control. Negative values are an indication that the emission rate associated with the control is greater than the current emission rate of the unit in question, which means the control would not be expected to reduce emissions. Controls that would not reduce emissions are not cost-effective on their face and were not considered further.
[(3)] Because estimated reductions are zero, and division by zero is undefined, cost effectiveness cannot be calculated for replacement of this unit.

NMED also evaluated the ATS at LRGP due to the potential for significant SO_2 emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). NMED concluded that a FFA of potential control measures for SO_2 for the ATS was not required because the most effective ATS control available – an AGI well with redundant compression – is already being utilized at LRGP.

7.5.4.3 Control Measures Determination

NMED's FFA did not identify any cost-effective controls for LRGP Units 6, 7, 8, 9, 10, 11, 29, 30, 31, or 32B. Therefore, NMED determined that reasonable progress does not require new controls on any of these units. However, as discussed in Section 8.2.3, Units 29, 30, 31, and 32B are already equipped (or in the process of being equipped) with DLN, which was a major, if not the deciding factor in the outcome of NMED's analyses. As a result, NMED determined that continued use of the existing controls on these units is necessary for reasonable progress.

As noted above, NMED did not conduct a FFA of potential control measures for LRGP's ATS. Because the most effective control available – an AGI well with redundant compression – is already being utilized at LRGP, NMED determined that reasonable progress does not require new controls for the ATS.

7.5.5 El Paso Natural Gas Company, LLC – Blanco Compressor Station A

7.5.5.1 Facility Description

Blanco Compressor Station A (BCSA) is a natural gas compressor station located 0.1 miles north of Bloomfield in San Juan County, New Mexico at latitude 36° 43' 42", longitude -107° 57' 21". It is owned and operated by El Paso Natural Gas Company, LLC (EPNG), a subsidiary of Kinder Morgan, and currently operates under Title V Operating Permit No. P048-R4, which expires on September 18, 2025. The shortest distance to the boundary of the nearest Class I Area, Mesa Verde National Park, is approximately 39.8 miles.

The function of the facility is to compress natural gas for the purpose of transportation to another facility or a major transportation pipeline. The facility is authorized for continuous operation, and its total potential to emit is 1344 tons per year of NO_X and 0.3 tons per year of SO_2.

7.5.5.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for NO_X for fourteen (14) 2SLB RICE at BCSA that met the tier two screening criteria described in Chapter 6. NMED's analysis of the four statutory factors for these units is discussed in detail in Section C.5.5.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
A01	LEC1	$48,000	1-3	20	None
	LEC2	$42,000	1-3	20	None
	LEC3	$36,000	1-3	20	None
	Replacement	$23,000	3-4	30	None
A02	LEC1	$164,000	1-3	20	None

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [1]
	LEC2	$122,000	1-3	20	None
	LEC3	$101,000	1-3	20	None
	Replacement	$65,000	3-4	30	None
A03	LEC1	$111,000	1-3	20	None
	LEC2	$60,000	1-3	20	None
	LEC3	$49,000	1-3	20	None
	Replacement	$31,000	3-4	30	None
A04	LEC1	-$103,000	1-3	20	None
	LEC2	$711,000	1-3	20	None
	LEC3	$286,000	1-3	20	None
	Replacement	$185,000	3-4	30	None
A05	LEC1	$2,975,000	1-3	20	None
	LEC2	$2,641,000	1-3	20	None
	LEC3	$2,245,000	1-3	20	None
	Replacement	$1,448,000	3-4	30	None
A06	LEC1	$114,000	1-3	20	None
	LEC2	$101,000	1-3	20	None
	LEC3	$86,000	1-3	20	None
	Replacement	$56,000	3-4	30	None
A07	LEC1	$40,000	1-3	20	None
	LEC2	$36,000	1-3	20	None
	LEC3	$30,000	1-3	20	None
	Replacement	$20,000	3-4	30	None
A08	LEC1	$177,879,000	1-3	20	None
	LEC2	$157,945,000	1-3	20	None
	LEC3	$134,231,000	1-3	20	None
	Replacement	$86,605,000	3-4	30	None
A09	LEC1	$58,000	1-3	20	None
	LEC2	$54,000	1-3	20	None
	LEC3	$46,000	1-3	20	None
	Replacement	$30,000	3-4	30	None
A10	LEC1	$80,854,000	1-3	20	None
	LEC2	$71,793,000	1-3	20	None
	LEC3	$61,014,000	1-3	20	None
	Replacement	$39,366,000	3-4	30	None
A11	LEC1	$11,000	1-3	20	None
	LEC2	$13,000	1-3	20	None
	LEC3	$11,000	1-3	20	None
	Replacement	$7,000	3-4	30	None
A12	LEC1	$235,000	1-3	20	None
	LEC2	$209,000	1-3	20	None
	LEC3	$177,000	1-3	20	None
	Replacement	$114,000	3-4	30	None

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [1]
A13	LEC1	$14,000	1-3	20	None
	LEC2	$16,000	1-3	20	None
	LEC3	$14,000	1-3	20	None
	Replacement	$9,000	3-4	30	None
A14	LEC1	$84,000	1-3	20	None
	LEC2	$75,000	1-3	20	None
	LEC3	$63,000	1-3	20	None
	Replacement	$41,000	3-4	30	None
All Units	Electrification	$20,000	4-6	25	None

[1] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

7.5.5.3 Control Measures Determination

Based on its analysis of the four statutory factors, the cost effectiveness threshold described in Section 7.3, and the control selection criteria described in Section 7.4, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
A11	Replacement	51.7
A13	Replacement	42.1

NMED did not identify any cost-effective controls for BCSA Units A01, A02, A03, A04, A05, A06, A07, A08, A09, A10, A12, or A14. Therefore, NMED determined that reasonable progress does not require new controls on any of these units.

7.5.6 El Paso Natural Gas Company, LLC – Pecos River Compressor Station

7.5.6.1 Facility Description

Pecos River Compressor Station (PRCS) is a natural gas compressor station located approximately 11.5 miles south-southeast of Malaga in Eddy County, New Mexico at latitude 32° 03' 49", longitude -104° 01' 06". It is owned and operated by EPNG and currently operates under Title V Operating Permit No. P129-R4, which expires on March 4, 2026. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 22.1 miles.

The function of the facility is to compress natural gas and deliver the compressed gas to a pipeline for mainline transportation. The facility is authorized for continuous operation, and its total potential to emit is 697.7 tons per year of NO_X and 5.6 tons per year of SO_2.

7.5.6.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for three (3) combustion turbines at PRCS that met the tier two screening criteria described in Chapter 6. NMED's analysis of the four statutory factors for these units is discussed in detail in Section C.5.6.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [1]
A-01	SCR	$13,000	3	20	None
	Replacement	$38,000	3-4	30	None
A-02	SCR	$8,000	3	20	None
	Replacement	$23,000	3-4	30	None
A-03	SCR	$9,000	3	20	None
	Replacement	$24,000	3-4	30	None
All Units	Electrification	$28,000	4-6	25	None

[1] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

7.5.6.3 Control Measures Determination

Based on its analysis of the four statutory factors, the cost effectiveness threshold described in Section 7.3, and the control selection criteria described in Section 7.4, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
A-02	SCR	92.8
A-03	SCR	89.8

NMED's FFA did not identify any cost-effective controls for PRCS Unit A-01. Therefore, NMED determined that reasonable progress does not require new controls on this unit.

7.5.7 El Paso Natural Gas Company, LLC – Washington Ranch Storage Facility

7.5.7.1 Facility Description

Washington Ranch Storage Facility (WRSF) is a natural gas storage facility located 9.1 miles southwest of Whites City in Eddy County, New Mexico at latitude 32° 04' 54", longitude -104° 29' 04". It is owned and operated by EPNG and currently operates under Title V Operating Permit No. P064-R4M2, which expires on December 30, 2025. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 3.4 miles.

The function of the facility is to compress and inject natural gas into underground storage wells and to withdraw the gas for delivery into the pipeline. The facility is authorized for continuous operation, and its total potential to emit is 243.6 tons per year of NO_X and 4.8 tons per year of SO_2.

7.5.7.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for two (2) 2SLB RICE at WRSF that met the tier two screening criteria described in Chapter 6. NMED's analysis of the four statutory factors for these units is discussed in detail in Section C.5.7.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [1]
1	Replacement	$316,000	3-4	30	None
2	Replacement	$1,136,000	3-4	30	None
All Units	Electrification	$239,000	4-6	25	None

[1] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

7.5.7.3 Control Measures Determination

NMED's FFA did not identify any cost-effective controls for WRSF Units 1 and 2. Therefore, NMED determined that reasonable progress does not require new controls on either of these units. However, as discussed in Section 8.2.3, both units are already equipped with LEC, which was a major, if not the deciding factor in the outcome of NMED's analyses. As a result, NMED determined that continued use of the existing controls on these units is necessary for reasonable progress.

7.5.8 Enterprise Field Services, LLC – Blanco C&D Compressor Station

7.5.8.1 Facility Description

Blanco C&D Compressor Station (BCDCS) is a natural gas compressor station located 2 miles northeast of Bloomfield in San Juan County, New Mexico at latitude 36° 43' 57", longitude -107° 57' 42". It is owned by Enterprise Field Services, LLC and operated by Enterprise Products Operating, LLC, and currently operates under Title V Operating Permit No. P218-R3, which expires on October 28, 2025. The shortest distance to the boundary of the nearest Class I Area, Mesa Verde National Park, is approximately 40 miles.

The function of the facility is to compress natural gas for the purpose of transportation to another facility or a major transportation pipeline. The facility is authorized for continuous operation, and its total potential to emit is 1332.6 tons per year of NO_X and 4.0 tons per year of SO_2.

7.5.8.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for three (3) combustion turbines at BCDCS that met the tier two screening criteria described in Chapter 6. NMED's analysis of the four statutory factors for these units is discussed in detail in Section C.5.8.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [1]
T-C01	WSI	$12,000	3-4	15	None
	SCR	$6,000	3-4	20	None
	Replacement	$34,000	3-4	30	None
	Electrification	$35,000	4-6	25	None
T-C02	WSI	$9,000	3-4	15	None
	SCR	$5,000	3-4	20	None
	Replacement	$32,000	3-4	30	None
	Electrification	$34,000	4-6	25	None

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [1]
T-D01	DLN	$3,000	3-4	20	None
	WSI	$4,000	3-4	15	None
	SCR	$4,000	3-4	20	None
	Replacement	$26,000	3-4	30	None
	Electrification	$28,000	4-6	25	None

[1] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

7.5.8.3 Control Measures Determination

NMED's FFA identified cost-effective controls for BCDCS Units T-C01, T-C02, and T-D01. Based on its analysis of the four statutory factors and the decision-making criteria described above, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
T-C01	SCR	223.1
T-C02	SCR	230.4
T-D01	SCR	412.6

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
T-C02	WSI	Less stringent than SCR
T-D01	DLN	Less stringent than SCR
T-D01	WSI	Less stringent than SCR

7.5.9 Enterprise Field Services, LLC – Chaco Gas Plant

7.5.9.1 Facility Description

Chaco Gas Plant (CGP) is a natural gas processing facility located 14 miles southwest of Bloomfield in San Juan County, New Mexico at latitude 36° 29' 00", longitude -108° 07' 13". It is owned by Enterprise Field Services, LLC and operated by Enterprise Products Operating, LLC, and currently operates under Title V Operating Permit No. P116-R3, which expires on November 13, 2025. The shortest distance to the boundary of the nearest Class I Area, Mesa Verde National Park, is approximately 49.8 miles.

The function of the facility is to receive field natural gas, process the gas through removal of water, then extract/separate natural gas liquids (NGL) through a cryogenic process. Recovered NGL are then treated to remove carbon dioxide and hydrogen sulfide, and then delivered to a pipeline for transport to fractionation facilities downstream. The facility is authorized for continuous operation, and its total potential to emit is 2608.6 tons per year of NO_X and 91.8 tons per year of SO_2.

7.5.9.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for three (3) 2SLB RICE engines and five (5) combustion turbines at CGP that met the tier two screening criteria described in Chapter 6.

NMED's analysis of the four statutory factors for these units is discussed in detail in Section C.5.9.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
12	LEC	$12,000	2-3	20	None
	Replacement	$20,000	3-4	30	None
	Electrification	$15,000	4-6	25	None
13	LEC	$30,000	2-3	20	None
	Replacement	$45,000	3-4	30	None
	Electrification	$30,000	4-6	25	None
14	LEC	$8,000	2-3	20	None
	Replacement	$13,000	3-4	30	None
	Electrification	$10,000	4-6	25	None
17	WSI	-$46,000	3-4	15	None
	SCR	$19,000	3-4	20	None
	Replacement	$131,000	3-4	30	None
	Electrification	$114,000	4-6	25	None
18	WSI	-$55,000	3-4	15	None
	SCR	$18,000	3-4	20	None
	Replacement	$119,000	3-4	30	None
	Electrification	$106,000	4-6	25	None
35	DLN	$11,000	3-4	20	None
	SCR	$11,000	3-4	20	None
	Replacement	$65,000	3-4	30	None
	Electrification	$63,000	4-6	25	None
36	DLN	$12,000	3-4	20	None
	SCR	$12,000	3-4	20	None
	Replacement	$67,000	3-4	30	None
	Electrification	$62,000	4-6	25	None
37	DLN	$13,000	3-4	20	None
	SCR	$13,000	3-4	20	None
	Replacement	$77,000	3-4	30	None
	Electrification	$67,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

NMED also elected to evaluate the ATS at CGP for potential control measures for SO_2 due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). NMED concluded that a FFA of potential control measures for SO_2 for the ATS was not required because alternatives to the existing TO are either inferior, presumptively not cost effective, or both.

7.5.9.3 Control Measures Determination

Based on its analysis of the four statutory factors, the cost effectiveness threshold described in Section 7.3, and the control selection criteria described in Section 7.4, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
14	LEC	118.3

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
14	Electrification	Categorically excluded

NMED's FFA did not identify any cost-effective controls for CGP Units 12, 13, 17, 18, 35, 36, or 37. Therefore, NMED determined that reasonable progress does not require new controls on any of these units. As noted above, NMED did not conduct a FFA of potential control measures for CGP's ATS. Because the alternatives to the existing TO are either inferior, presumptively not cost effective, or both, NMED determined that reasonable progress does not require new controls for the ATS.

7.5.10 Enterprise Field Services, LLC – South Carlsbad Compressor Station

7.5.10.1 Facility Description

South Carlsbad Compressor Station (SCCS) is a natural gas compressor station located 2.8 miles northwest of Loving in Eddy County, New Mexico at latitude 32° 18' 56", longitude -104° 08' 12". It is owned by Enterprise Field Services, LLC and operated by Enterprise Products Operating, LLC, and currently operates under Title V Operating Permit No. P130-R4, which expires on June 9, 2028. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 16.2 miles.

The function of the facility is to compress gas to direct to a pipeline for transport. The facility is authorized for continuous operation, and its total potential to emit is 211.3 tons per year of NO_X and 17.0 tons per year of SO_2.

7.5.10.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for two (2) combustion turbines at SCCS that met the tier two screening criteria described in Chapter 6. NMED's analysis of the four statutory factors for these units is discussed in detail in Section C.5.10.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
1	DLN	$4,000	3-4	20	None
	SCR	$6,000	3-4	20	None
	Replacement	$23,000	3-4	30	None
	Electrification	$25,000	4-6	25	None

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
2	DLN	$4,000	3-4	20	None
	SCR	$7,000	3-4	20	None
	Replacement	$24,000	3-4	30	None
	Electrification	$25,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

7.5.10.3 Control Measures Determination

Based on its analysis of the four statutory factors, the cost effectiveness threshold described in Section 7.3, and the control selection criteria described in Section 7.4, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
1	DLN	68.0
2	DLN	67.7

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
1	SCR	Less stringent than DLN
2	SCR	Less stringent than DLN

7.5.11 ET Gathering & Processing LLC – Jal #3 Gas Plant

7.5.11.1 Facility Description

Jal #3 Gas Plant (JGP) is a natural gas processing facility located 4 miles north-northeast of Jal in Lea County, New Mexico at latitude 32° 10' 25", longitude -103° 10' 27". It is owned and operated by ET Gathering & Processing LLC – formerly ETC Texas Pipeline, LTD (ETC) – and currently operates under Title V Operating Permit No. P090-R3M1, which expired on March 27, 2024. [162] The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 70 miles.

7.5.11.2 Summary of Four-Factor Analysis

JGP was one of 23 facilities selected for an analysis of potential control measures when NMED performed the source screening described in Chapter 6 in 2019. NMED originally selected two (2) 2SLB RICE at JGP for an analysis of potential control measures for NO_X in the second planning period. NMED also elected to evaluate the ATS at JGP for potential control measures for SO_2 due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). However, due to subsequent changes at JGP, NMED did not perform a four-factor analysis for any of the emissions units at JGP.

[162] ETC submitted a timely application to renew Title V Operating Permit No. P090-R3M1 in March 2023. At the time of preparation of this Regional Haze SIPr Rd2 (2019-2028), NMED had not taken final action on the application. Pursuant to 20.2.70.201 NMAC, a Title V source may continue to operate after its operating permit expires if it has submitted a timely renewal application and meets other requirements.

As discussed in Section C.5.11 of Appendix C, ETC has retired the two 2SLB RICE originally selected for analysis and removed them from JGP's NSR permit. ETC has also reconfigured JGP's ATS, eliminating the SRU and adding redundant compression to the AGI well, which is now the primary control for the ATS. There is no more effective control for RICE than retirement, which reduces emissions by 100 percent, and an AGI well with redundant compression is the most effective control for ATS. Therefore, NMED has determined that these units are already effectively controlled, and that a FFA could only result in the conclusion that no further controls are necessary to make reasonable progress.

7.5.11.3 Control Measures Determination

Because they are already effectively- controlled, NMED determined that reasonable progress does not require new controls on the two retired 2SLB RICE originally selected for analysis or the ATS at JGP.

7.5.12 Transwestern Pipeline Company, LLC – Mountainair Compressor Station No. 7

7.5.12.1 Facility Description

Mountainair Compressor Station No. 7 (MCS) is a natural gas compressor station located 12 miles south-southwest of Mountainair in Torrance County, New Mexico at latitude 34^{o} 20' 29", longitude -106^{o} 17' 51". It is owned and operated by Transwestern Pipeline Company, LLC (TWP), and currently operates under Title V Operating Permit No. P153-R4, which expires on October 14, 2025. The shortest distance to the boundary of the nearest Class I Area, Bosque del Apache Wilderness Area, is approximately 50 miles.

The facility services a natural gas pipeline system, removing small amounts of entrained liquid from the gas stream before directing it back into the pipeline at a higher pressure. The facility is authorized for continuous operation, and its total potential to emit is 2263.5 tons per year of NO_X.

7.5.12.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for three (3) 4SLB RICE and two (2) 4SRB RICE at MCS that met the tier two screening criteria described in Chapter 6. NMED's analysis of the four statutory factors for these units is discussed in detail in Section C.5.12.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
701	LEC	$3,000	2-5	20	None
	SCR	$1,000	2-5	20	None
702	LEC	$2,000	2-5	20	None
	SCR	$1,000	2-5	20	None
703	LEC	$2,000	2-5	20	None
	SCR	$1,000	2-5	20	None
721	LEC	$1,000	2-5	20	None
722	LEC	$6,000	2-5	20	None
All Units	Replacement	$3,000	3-4	30	None
	Electrification	$7,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

7.5.12.3 Control Measures Determination

Based on its analysis of the four statutory factors, the cost effectiveness threshold described in Section 7.3, and the control selection criteria described in Section 7.4, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
701	Replacement [(1)]	362.0
702	Replacement [(1)]	445.1
703	Replacement [(1)]	413.7
721	Replacement [(1)]	50.3
722	Replacement [(1)]	13.4

[(1)] The replacement scenario evaluated by NMED for MCS involves replacing Units 701, 702, and 703 two functionally equivalent CT and replacing Units 721 and 722 with microturbine generators.

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
701	LEC	Less stringent than replacement
701	SCR	Less stringent than replacement
701	Electrification	Categorically excluded
702	LEC	Less stringent than replacement
702	SCR	Less stringent than replacement
702	Electrification	Categorically excluded
703	LEC	Less stringent than replacement
703	SCR	Less stringent than replacement
703	Electrification	Categorically excluded
721	LEC	Less stringent than replacement
722	LEC	Less stringent than replacement

7.5.13 Transwestern Pipeline Company, LLC – Roswell Compressor Station No. 9

7.5.13.1 Facility Description

Roswell Compressor Station No. 9 (RCS) is a natural gas compressor station located 5 miles north of Roswell in Chaves County, New Mexico at latitude 33° 30' 37", longitude -104° 31' 08". It is owned and operated by TWP and currently operates under Title V Operating Permit No. P154-R4, which expired on September 28, 2023. [163] The shortest distance to the boundary of the nearest Class I Area, Salt Creek Wilderness Area, is approximately 5.6 miles.

[163] Transwestern Pipeline Company, LLC submitted a timely application to renew Title V Operating Permit No. P154-R4 in September 2022. At the time of preparation of this Regional Haze SIPr Rd2 (2019-2028), NMED had not taken final action on the application. Pursuant to 20.2.70.201 NMAC, a Title V source may continue to operate after its operating permit expires if it has submitted a timely renewal application and meets other requirements.

The facility services a natural gas pipeline system, removing small amounts of entrained liquid from the gas stream before directing it back into the pipeline at a higher pressure. The facility is authorized for continuous operation, and its total potential to emit is 1122.5 tons per year of NO_X and 0.8 tons per year of SO_2.

7.5.13.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for two (2) 4SLB RICE at RCS that met the tier two screening criteria described in Chapter 6. NMED's analysis of the four statutory factors for these units is discussed in detail in Section C.5.13.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
903	LEC	$2,000	2-5	20	None
	SCR	$1,000	2-5	20	None
904	LEC	$6,000	2-5	20	None
	SCR	$2,000	2-5	20	None
All Units	Replacement	$3,000	3-4	30	None
	Electrification	$9,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

7.5.13.3 Control Measures Determination

Based on its analysis of the four statutory factors, the cost effectiveness threshold described in Section 7.3, and the control selection described in Section 7.4, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
903	Replacement [(1)]	443.7
904	Replacement [(1)]	201.0

[(1)] The replacement scenario evaluated by NMED for RCS involves replacing Units 903 and 904 with one functionally equivalent CT.

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
903	LEC	Less stringent than replacement
903	SCR	Less stringent than replacement
903	Electrification	Categorically excluded
904	LEC	Less stringent than replacement
904	SCR	Less stringent than replacement
904	Electrification	Categorically excluded

7.5.14 Harvest Four Corners, LLC – Kutz Canyon Processing Plant

7.5.14.1 Facility Description

Kutz Canyon Processing Plant (KCPP) is a natural gas processing facility located approximately 3.5 miles south of Bloomfield, in San Juan County, New Mexico at latitude 36° 40' 11", longitude -107° 57' 42". It is owned and operated by Harvest Four Corners, LLC, and currently operates under Title V Operating Permit No. P097-R4, which expires on January 3, 2028. The shortest distance to the boundary of the nearest Class I Area, Mesa Verde National Park, is approximately 43.2 miles.

The function of the facility is to remove ethane and heavier hydrocarbons from natural gas through refrigerating lean oil absorption and cryogenic processes. The facility is authorized for continuous operation, and its total potential to emit is 603.3 tons per year of NO_X and 1.4 tons per year of SO_2.

7.5.14.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for eight (8) combustion turbines at KCPP that met the tier two screening criteria described in Chapter 6. NMED's analysis of the four statutory factors for these units is discussed in detail in Section C.5.14.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [1]
1	SCR	$6,000	3-4	20	None
	DLN	$6,000	2-3	20	None
	Replacement	$27,000	3-4	30	None
2	SCR	$8,000	3-4	20	None
	DLN	$7,000	2-3	20	None
	Replacement	$33,000	3-4	30	None
3	SCR	$11,000	3-4	20	None
	DLN	$11,000	2-3	20	None
	Replacement	$54,000	3-4	30	None
4	SCR	$8,000	3-4	20	None
	DLN	$8,000	2-3	20	None
	Replacement	$38,000	3-4	30	None
5	SCR	$9,000	3-4	20	None
	DLN	$9,000	2-3	20	None
	Replacement	$45,000	3-4	30	None
6	SCR	$8,000	3-4	20	None
	DLN	$16,000	2-3	20	None
	Replacement	$76,000	3-4	30	None
19	SCR	$8,000	3-4	20	None
	DLN	$10,000	2-3	20	None
	Replacement	$37,000	3-4	30	None
20	SCR	$10,000	3-4	20	None
	DLN	$12,000	2-3	20	None
	Replacement	$46,000	3-4	30	None

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [1]
All Units	Electrification	$18,000	4-6	25	None

[1] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

7.5.14.3 Control Measures Determination

Based on its analysis of the four statutory factors, the cost effectiveness threshold described in Section 7.3, and the control selection described in Section 7.4, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
1	SCR	46.4
2	SCR	38.0
4	SCR	36.9
5	SCR	33.0
6	SCR	38.7
19	SCR	30.1
20	SCR	24.3

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
1	DLN	Less stringent than SCR
2	DLN	Less stringent than SCR
4	DLN	Less stringent than SCR
5	DLN	Less stringent than SCR
19	DLN	Less stringent than SCR

NMED's FFA did not identify any cost-effective controls for KCPP Unit 3. Therefore, NMED determined that reasonable progress does not require new controls on this unit.

7.5.15 Hilcorp Energy Company – San Juan Basin Gas Plant

7.5.15.1 Facility Description

San Juan Basin Gas Plant (SJBGP) is a natural gas processing facility located approximately 2 miles northeast of Bloomfield in San Juan County, New Mexico at latitude 36° 43' 57", longitude -107° 57' 59". It is owned and operated by Hilcorp Energy Company and currently operates under Title V Operating Permit No. P124-R4, which expires on March 10, 2028. The shortest distance to the boundary of the nearest Class I Area, Mesa Verde National Park, is approximately 39.6 miles.

The function of the facility is to extract and process natural gas liquids and residue gas products from field gas. The facility is authorized for continuous operation, and its total potential to emit is 1050.1 tons per year of NO_X and 18.3 tons per year of SO_2.

7.5.15.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for seven (7) combustion turbines at SJBGP that met the tier two screening criteria described in Chapter 6. NMED's analysis of the four statutory factors for these units is discussed in detail in Section C.5.15.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [1]
1	DLN	$351,000	2-3	20	None
	SCR	$10,000	3-4	20	None
	Replacement	$124,000	3-4	30	None
2	DLN	$237,000	2-3	20	None
	SCR	$10,000	3-4	20	None
	Replacement	$113,000	3-4	30	None
3	DLN	-$4,990,000 [2]	2-3	20	None
	SCR	$10,000	3-4	20	None
	Replacement	$130,000	3-4	30	None
4	DLN	$9,000	2-3	20	None
	SCR	$5,000	2-3	20	None
	Replacement	$30,000	3-4	30	None
5	DLN	$9,000	2-3	20	None
	SCR	$5,000	2-3	20	None
	Replacement	$30,000	3-4	30	None
6	DLN	$8,000	2-3	20	None
	SCR	$5,000	2-3	20	None
	Replacement	$26,000	3-4	30	None
7	DLN	$9,000	2-3	20	None
	SCR	$5,000	2-3	20	None
	Replacement	$28,000	3-4	30	None
All Units	Electrification	$31,000	4-6	25	None

[1] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.
[2] Negative cost effectiveness is an artifact of NMED's method for calculating this value and does not accurately represent the cost effectiveness of the control. Negative values are an indication that the emission rate associated with the control is greater than the current emission rate of the unit in question, which means the control would not be expected to reduce emissions. Controls that would not reduce emissions are not cost-effective on their face and were not considered further.

NMED also elected to evaluate the ATS at SJBGP for potential control measures for SO_2 due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). NMED concluded that a FFA of potential control measures for SO_2 for the ATS was not required because alternatives to the existing TO are either inferior, presumptively not cost effective, or both.

7.5.15.3 Control Measures Determination

Based on its analysis of the four statutory factors, the cost effectiveness threshold described in Section 7.3, and the control selection described in Section 7.4, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
1	SCR	66.9
2	SCR	72.3
3	SCR	66.5
4	SCR	44.5
5	SCR	44.0
6	SCR	48.7
7	SCR	45.5

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
4	DLN	Less stringent than SCR
5	DLN	Less stringent than SCR
6	DLN	Less stringent than SCR
7	DLN	Less stringent than SCR

As noted above, NMED did not conduct a FFA of potential control measures for SJBGP's ATS. Because the alternatives to the existing TO are either inferior, presumptively not cost effective, or both, NMED determined that reasonable progress does not require new controls for the ATS.

7.5.16 IACX Roswell, LLC – Bitter Lake Compressor Station

7.5.16.1 Facility Description

Bitter Lake Compressor Station (BLCS) is a natural gas compressor station located 13.3 miles northeast of Roswell in Chaves County, New Mexico at latitude 33° 33' 11", longitude -104° 23' 27". It is owned and operated by IACX Roswell, LLC, and is currently authorized as a synthetic minor source under New Source Review Permit No. 0274-M8. The facility previously operated as a major source under Title V Operating Permit No. P047-R3, which was cancelled at IACX's request on March 13, 2020. The shortest distance to the boundary of the nearest Class I Area, Salt Creek Wilderness Area, is approximately 1.1 miles.

The function of the facility is to gather casinghead gas from multiple wells and compress the gas using natural gas-fired compressor engines. The facility is authorized for continuous operation, and its total potential to emit is 79.6 tons per year of NO_X and 1.5 tons per year of SO_2.

7.5.16.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for two (2) 2SLB RICE at BLCS that met the tier two screening criteria described in Chapter 6. NMED's analysis of the four statutory factors for these units is discussed in detail in Section C.5.16.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
C-891	LEC	-$9,000 [(2)]	2	20	None
	Replacement	$70,000	3-4	30	None
C-893	LEC	-$10,000 [(2)]	2	20	None
	Replacement	$82,000	3-4	30	None
All Units	Electrification	$46,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.
[(2)] Negative cost effectiveness is an artifact of NMED's method for calculating this value and does not accurately represent the cost effectiveness of the control. Negative values are an indication that the emission rate associated with the control is greater than the current emission rate of the unit in question, which means the control would not be expected to reduce emissions. Controls that would not reduce emissions are not cost-effective on their face and were not considered further.

7.5.16.3 Control Measures Determination

NMED's FFA did not identify any cost-effective controls for BLCS Units C-891 or C-893. Therefore, NMED determined that reasonable progress does not require new controls on either of these units. However, as discussed in Section 8.2.3, both units are already equipped with LEC, which was a major, if not the deciding factor in the outcome of NMED's analyses. As a result, NMED determined that continued use of the existing controls on these units is necessary for reasonable progress.

7.5.17 Oxy USA WTP Limited Partnership – Oxy Indian Basin Gas Plant

7.5.17.1 Facility Description

Indian Basin Gas Plant (IBGP) is a natural gas processing facility located 14.5 miles west of Carlsbad in Eddy County, New Mexico at latitude 32° 27' 50", longitude -104° 34' 27". It is owned and operated by Oxy USA WTP Limited Partnership and currently operates under Title V Operating Permit No. P103-R3, which expires on November 1, 2024. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 21.2 miles.

The function of the facility is to remove hydrogen sulfide, carbon dioxide, condensate and water from raw natural gas to make commercial natural gas. The facility also extracts natural gas products (propane and butane) from natural gas. The facility is authorized for continuous operation, and its total potential to emit is 363.0 tons per year of NO_X and 87.1 tons per year of SO_2.

7.5.17.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for three (3) CT at IBGP that met the tier two screening criteria described in Chapter 6. NMED also performed a FFA for all technically feasible control options for the ATS at IBGP due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). NMED's analysis of the four statutory factors for these units is discussed in detail in Section C.5.17.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [1]
ES-06/07	DLN	$9,000	2-3	20	None
	SCR	$12,000	3-4	20	None
	Replacement	$27,000	3-4	30	None
ES-08/09	DLN	$9,000	2-3	20	None
	SCR	$12,000	3-4	20	None
	Replacement	$28,000	3-4	30	None
ES-10/11	DLN	$10,000	2-3	20	None
	SCR	$13,000	3-4	20	None
	Replacement	$38,000	3-4	30	None
All CT	Electrification	$31,000	4-6	25	None
ATS	Redundant Compression	$25,000	2-3	20	None

[1] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

7.5.17.3 Control Measures Determination

Based on its analysis of the four statutory factors, the cost effectiveness threshold described in Section 7.3, and the control selection criteria described in Section 7.4, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
ES-06/07	DLN	36.5
ES-08/09	DLN	35.0
ES-10/11	DLN	29.0

NMED's FFA did not identify any cost-effective controls for the ATS at IBGP. Therefore, NMED determined that reasonable progress does not require new controls for the ATS.

7.5.18 Public Service Company of New Mexico – San Juan Generating Station

7.5.18.1 Facility Description

San Juan Generating Station (SJGS) is a former 1,800 MW coal-fired electric power plant located 3 miles north of Waterflow in San Juan County, New Mexico at latitude 36° 48' 07", longitude -108° 26' 20". It is owned by Public Service Company of New Mexico (PNM) and was one of 23 facilities selected for an analysis of potential control measures when NMED performed the source screening described in Chapter 6 in 2019. However, PNM subsequently shut down SJGS on or about November 1, 2022, and submitted an administrative permit revision closing NSR Permit No. 0063-M12R3 and voluntarily discontinuing Title V Operating Permit No. P062-R4M1 on December 27, 2022. PNM's demolition and remediation plan for the facility was approved by the San Juan County Commission on March 7, 2023, and demolition was initiated on July 10, 2023, with the majority of the work expected to be completed by the end of 2025.

7.5.18.2 Summary of Four-Factor Analysis

NMED originally selected SJGS' two coal-fired boilers for an analysis of potential control measures for NO_X and SO_2 in the second planning period. However, because SJGS has since been shut down and demolition is currently underway, NMED did not perform a FFA of potential control measures for these units. There is no more effective control for boilers than retirement, which reduces emissions by 100 percent. Therefore, NMED has determined that SJGS' boilers are already effectively controlled by virtue of their retirement, and that a FFA could only result in the conclusion that no further controls are necessary to make reasonable progress.

7.5.18.3 Control Measures Determination

Because they are already effectively controlled, NMED determined that reasonable progress does not require new controls on the two retired boilers at SJGS.

7.5.19 Targa Midstream Services, LLC – Eunice Gas Processing Plant

7.5.19.1 Facility Description

Eunice Gas Processing Plant (EGPP) is a natural gas processing facility located one mile southeast of Eunice in Lea County, New Mexico at latitude 32° 25' 28", longitude -103° 08' 50". It is owned by Versado Gas Processors, LLC and operated by Targa Midstream Services, LLC, and currently operates under Title V Operating Permit No. P109-R3M1, which expires on November 29, 2024. [164] The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 73.5 miles.

The function of the facility is to receive field natural gas, perform dehydration and removal of carbon dioxide and hydrogen sulfide, and separate natural gas liquids. The facility is authorized for continuous operation, and its total potential to emit is 2606.0 tons per year of NO_X and 482.0 tons per year of SO_2.

7.5.19.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for two (2) industrial boilers and seven (7) 2SLB RICE at EGPP that met the tier two screening criteria described in Chapter 6. NMED's analysis of the four statutory factors for these units is discussed in detail in Section C.5.19.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts (1)
B-01	FGR	$3,000	2-3	30	None
	LNB	$3,000	2-3	30	None
	SCR	$17,000	2-3	30	None
	Replacement	$8,000	3-4	30	None
B-02	FGR	$3,000	2-3	30	None
	LNB	$3,000	2-3	30	None
	SCR	$17,000	2-3	30	None

[164] Targa submitted a timely application to renew Title V Operating Permit No. P109-R3M1 on November 28, 2023. At the time of preparation of this Regional Haze SIPr Rd2 (2019-2028), NMED had not taken final action on the application.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [1]
	Replacement	$8,000	3-4	30	None
C-01	LEC	$2,000	2-3	20	None
	Replacement	$2,000	3-4	30	None
C-02	LEC	$2,000	2-3	20	None
	Replacement	$3,000	3-4	30	None
C-03	LEC	$2,000	2-3	20	None
	Replacement	$3,000	3-4	30	None
C-04	LEC	$2,000	2-3	20	None
	Replacement	$2,000	3-4	30	None
C-05	LEC	$2,000	2-3	20	None
	Replacement	$2,000	3-4	30	None
C-06	LEC	$2,000	2-3	20	None
	Replacement	$3,000	3-4	30	None
C-07	LEC	$2,000	2-3	20	None
	Replacement	$2,000	3-4	30	None
C-01, C-02, C-03	Electrification	$2,000	4-6	25	None
C-04, C-05, C-06	Electrification	$2,000	4-6	25	None
C-07 and C-13	Electrification	$3,000	4-6	25	None

[1] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

NMED also evaluated the ATS at EGPP due to the potential for significant SO_2 emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). NMED concluded that a FFA of potential control measures for SO_2 for the ATS was not required because the most effective ATS control available – an AGI well with redundant compression – is already being utilized at EGPP.

7.5.19.3 Control Measures Determination

Based on its analysis of the four statutory factors, the cost effectiveness threshold described in Section 7.3, and the control selection criteria described in Section 7.4, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
B-01	LNB	23.5
B-02	LNB	23.5
C-01	Replacement	194.5
C-02	Replacement	165.7
C-03	Replacement	162.4
C-04	Replacement	185.3
C-05	Replacement	195.2

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
C-06	Replacement	157.5
C-07	Replacement	180.0

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
B-01	FGR	Less stringent than LNB
B-01	Replacement	Same stringency as LNB but less cost-effective
B-02	FGR	Less stringent than LNB
B-02	Replacement	Same stringency as LNB but less cost-effective
C-01	LEC	Less stringent than replacement
C-01	Electrification	Categorically excluded
C-02	LEC	Less stringent than replacement
C-02	Electrification	Categorically excluded
C-03	LEC	Less stringent than replacement
C-03	Electrification	Categorically excluded
C-04	LEC	Less stringent than replacement
C-04	Electrification	Categorically excluded
C-05	LEC	Less stringent than replacement
C-05	Electrification	Categorically excluded
C-06	LEC	Less stringent than replacement
C-06	Electrification	Categorically excluded
C-07	LEC	Less stringent than replacement
C-07	Electrification	Categorically excluded

As noted above, NMED did not conduct a FFA of potential control measures for EGPP's ATS. Because the most effective control available – an AGI well with redundant compression – is already being utilized at EGPP, NMED determined that reasonable progress does not require new controls for the ATS.

7.5.20 Targa Midstream Services, LLC – Monument Gas Plant

7.5.20.1 Facility Description

Monument Gas Plant (MGP) is a natural gas processing facility located 2.8 miles west of Monument in Lea County, New Mexico at latitude 32° 36' 38", longitude -103° 18' 44". It is owned by Versado Gas Processors, LLC and operated by Targa Midstream Services, LLC, and currently operates under Title V Operating Permit No. P110-R3M1, which expires on April 12, 2025. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 68.2 miles.

The function of the facility is to process natural gas through inlet separation, an amine system for acid gas removal (carbon dioxide and hydrogen sulfide), dehydration for water removal, and the separation of methane from natural gas liquids. The facility is authorized for continuous operation, and its total potential to emit is 1012.8 tons per year of NO_X and 372.9 tons per year of SO_2.

7.5.20.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for seven (7) 2SLB RICE at MGP that met the tier two screening criteria described in Chapter 6. NMED's analysis of the four statutory factors is discussed in detail in Section C.5.20.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
C-01	LEC	$11,000	2-3	20	None
	Replacement	$8,000	3-4	30	None
C-02	LEC	$5,000	2-3	20	None
	Replacement	$4,000	3-4	30	None
C-04	LEC	$20,000	2-3	20	None
	Replacement	$12,000	3-4	30	None
C-05	LEC	$4,000	2-3	20	None
	Replacement	$2,000	3-4	30	None
C-06	LEC	$16,000	2-3	20	None
	Replacement	$7,000	3-4	30	None
C-24	LEC	$2,000	2-3	20	None
	Replacement	$2,000	3-4	30	None
C-28	LEC	$14,000	2-3	20	None
	Replacement	$13,000	3-4	30	None
C-01, C-02	Electrification	$6,000	4-6	25	None
C-04, C-05, C-06	Electrification	$6,000	4-6	25	None
C-24	Electrification	$4,000	4-6	25	None
C-28	Electrification	$33,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

NMED also evaluated the ATS at MGP due to the potential for significant SO_2 emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). NMED concluded that a FFA of potential control measures for SO_2 for the ATS was not required because the most effective ATS control available – an AGI well with redundant compression – is already being utilized at MGP.

7.5.20.3 Control Measures Determination

Based on its analysis of the four statutory factors, the cost effectiveness threshold described in Section 7.3, and the control selection criteria described in Section 7.4, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
C-01	Replacement	36.2
C-02	Replacement	79.4
C-05	Replacement	95.6
C-06	Replacement	30.8
C-24	Replacement	167.0

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
C-01	Electrification	Categorically excluded
C-02	LEC	Less stringent than replacement
C-02	Electrification	Categorically excluded
C-04	Electrification	Categorically excluded
C-05	LEC	Less stringent than replacement
C-05	Electrification	Categorically excluded
C-06	Electrification	Categorically excluded
C-24	LEC	Less stringent than replacement
C-24	Electrification	Categorically excluded

NMED's FFA did not identify any cost-effective controls for MGP Unit C-28. Therefore, NMED determined that reasonable progress does not require new controls on this unit.

As noted above, NMED did not conduct a FFA of potential control measures for MGP's ATS. Because the most effective control available – an AGI well with redundant compression – is already being utilized at MGP, NMED determined that reasonable progress does not require new controls for the ATS.

7.5.21 Targa Midstream Services, LLC – Saunders Gas Plant

7.5.21.1 Facility Description

Saunders Gas Plant (SGP) is a former natural gas processing facility located 15 miles northwest of Lovington in Lea County, New Mexico at latitude 33° 03' 26", longitude -103° 36' 27". It is owned by Versado Gas Processors, LLC and operated by Targa Midstream Services, LLC (Targa), and was one of 23 facilities selected for an analysis of potential control measures when NMED performed the source screening described in Chapter 6 in 2019. However, Targa subsequently idled the facility and later decided to shut down gas plant operations at SGP permanently. On May 30, 2024, Targa submitted an administrative permit revision removing all of the units NMED selected for an analysis of potential control measures for NO_X and/or SO_2 from the facility's NSR and Title V permits and voluntarily discontinuing the Title V. The company intends to re-authorize the few remaining sources not selected for analysis under an oil and gas general construction permit.

7.5.21.2 Summary of Four-Factor Analysis

Because Targa has shut down gas plant operations at SGP, removed all of the units NMED selected for an analysis of potential control measures for NO_X and/or SO_2 from the facility's NSR and Title V permits, and discontinued the Title V, NMED did not perform a FFA of potential control measures for any of these units. There is no more effective control than retirement, which reduces emissions by 100 percent. Therefore, NMED has determined that all of the units selected for an analysis of potential control measures for NO_X and/or SO_2 are already effectively controlled by virtue of their retirement, and that a FFA could only result in the conclusion that no further controls are necessary to make reasonable progress.

7.5.21.3 Control Measures Determination

Because they are already effectively controlled, NMED determined that reasonable progress does not require new controls on any of the units selected for analysis at SGP.

7.5.22 Tri-State Generation and Transmission Association, Inc. – Prewitt Escalante Generating Station

7.5.22.1 Facility Description

Prewitt Escalante Generating Station (PEGS) is a former 268 MW coal-fired electric power plant located 4 miles north of Prewitt in McKinley County, New Mexico at latitude 35° 24' 57", longitude -108° 04' 58". It is owned by Tri-State Generation and Transmission Association, Inc. (Tri-State), and was one of 23 facilities selected for an analysis of potential control measures when NMED performed the source screening described in Chapter 6 in 2019. However, Tri-State subsequently shut down PEGS on August 31, 2020, and NMED voluntarily discontinued its Title V permit (Permit No. P012-R3) as of September 28, 2020. The plant is currently being decommissioned.

7.5.22.2 Summary of Four-Factor Analysis

NMED originally selected PEGS' main boiler for an analysis of potential control measures for NO_X and SO_2 in the second planning period, and its auxiliary boiler and plant heating boiler for an analysis of potential control measures for NO_X. However, because PEGS has since been shut down and is in the process of being decommissioned, NMED did not perform a FFA of potential control measures for any of these units. The main boiler is already effectively controlled by virtue of its retirement due to the shutdown of PEGS; ownership and operation of the auxiliary boiler has been transferred to a nearby minor source, removing it from consideration during the second planning period; and NMED has sufficient information to conclude that there are no cost effective controls for the plant heating boiler without performing a full four-factor analysis. NMED's evaluation of PEGS' boilers is described in detail in Section C.4.22 of Appendix C.

7.5.22.3 Control Measures Determination

Because they are already effectively controlled, have been transferred to an exempt source, or have no cost-effective controls available, NMED determined that reasonable progress does not require new controls on any of the boilers at PEGS.

7.5.23 Xcel Energy – Cunningham Station Power Plant

7.5.23.1 Facility Description

Cunningham Station Power Plant (CSPP) is a 487 MW electric power plant located 12.5 miles west of Hobbs in Lea County, New Mexico at latitude 32° 42' 44", longitude -103° 21' 13". It is owned and operated by Southwestern Public Service Company, a subsidiary of Xcel Energy, and currently operates under Title V Operating Permit No. P080-R4, which expires on April 9, 2026. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 69.4 miles.

The function of the facility is to provide commercial electric power using boilers and turbines fueled with natural gas. The facility is authorized for continuous operation, and its total potential to emit is 4,072.5 tons per year of NO_X and 155.8 tons per year of SO_2.

7.5.23.2 Summary of Four-Factor Analysis

NMED performed a FFA for all technically feasible control options for NO_X for two (2) utility boilers and two (2) combustion turbines at CSPP that met the tier two screening criteria described in Chapter 6.[165] NMED's analysis of the four statutory factors is discussed in detail in Section C.5.23.5 of Appendix C and the results are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
1	SCR	$7,000	2.5	30	None
2	SCR	$5,000	2.5	30	None
3	WI	$35,000	1.5	15	None
	SCR	$36,000	2.5	20	None
	Replacement	$237,000	3-4	30	None
4	WI	$26,000	1.5	15	None
	SCR	$33,000	2.5	20	None
	Replacement	$312,000	3-4	30	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

7.5.23.3 Control Measures Determination

Based on its analysis of the four statutory factors, the cost effectiveness threshold described in Section 7.3, and the control selection criteria described in Section 7.4, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
1	SCR	270.0
2	SCR	781.4

This determination only applies should either of these units operate beyond the end of the second planning period. If Xcel retires Units 1 and 2 on schedule, reasonable progress does not require new controls on either of these units as they will cease operating before controls could be installed.

NMED's FFA did not identify any cost-effective controls for CSPP Units 3 or 4. Therefore, NMED determined that reasonable progress does not require new controls on either of these units.

7.6 Estimated Emissions Reductions

Estimated total emissions reductions from sources subject to analysis in the second planning period are summarized below. These include reductions due to cost-effective controls NMED has determined are necessary to make reasonable progress, reductions due to unit retirements that occurred or are scheduled to occur during the second planning period, and reductions due to controls that have already been installed during the second planning period.

[165] Based on Xcel's current retirement schedule, neither of the boilers at CSPP is expected to operate beyond the end of the second planning period, which would preclude the installation of new controls. However, because the current retirement schedule is not a federally enforceable requirement, NMED evaluated the boilers as a backstop in case their retirement dates slip and one or both units continue to operate beyond 12/31/2028.

Table 7-1: Estimated emissions reductions in the second planning period.

Facility	Estimated Realized Reductions from Unit Retirements or Previously Installed Controls (ton/yr)		Estimated Pending Reductions from New Controls Required for Reasonable Progress (ton/yr)
	NO_X	**SO_2**	**NO_X**
Denton Gas Plant	---	708	---
Artesia Gas Plant	---	---	---
Eunice Gas Plant [166]	321.6	1,392.9	---
Linam Ranch Gas Plant	---	---	---
Blanco Compressor Station A	---	---	93.8
Pecos River Compressor Station	---	---	182.6
Washington Ranch Storage Facility	---	---	---
Blanco C&D Compressor Station	---	---	866.1
Chaco Gas Plant	---	---	118.3
South Carlsbad Compressor Station	---	---	135.7
Jal #3 Gas Plant	25.1	154.4	---
Mountainair Compressor Station No. 7	---	---	1284.5
Roswell Compressor Station No. 9	---	---	644.7
Kutz Canyon Processing Plant	245.4	---	247.4
San Juan Basin Gas Plant	---	---	388.4
Bitter Lake Compressor Station	---	---	---
Indian Basin Gas Plant	---	---	100.5
San Juan Generating Station	7,007.4	1,558.5	---
Eunice Gas Processing Plant [167]	492	308.2	1287.6
Monument Gas Plant	---	112.2	409
Saunders Gas Plant	632	284.8	---
Prewitt Escalante Generating Station	2,313.4	829.2	---
Cunningham Station Power Plant	1,168.2 (1)	---	---
Subtotals	**12,205.1**	**5,348.2**	**5,758.6**
Total Estimated NO_X Reductions	**17,963.7**		
Total Estimated SO_2 Reductions	**5,348.2**		

(1) Estimated reductions from unit retirements at Cunningham Station Power Plant have only been partially realized. Unit 1 has been shut down, but Unit 2 is still operating and is scheduled to be retired in 2027.

[166] DCP Operating Company LP – Eunice Gas Plant as discussed in Section 7.5.3.

[167] Targa Midstream Services, LLC - Eunice Gas Processing Plant as discussed in Section 7.5.19.

Chapter 8: Long-term Strategy for Second Planning Period

8.1 Regulatory Requirements

The Regional Haze Rule requires that this Regional Haze SIPr Rd 2 (2019-2028) contain "a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the state and for each mandatory Class I Federal area located outside the state that may be affected by emissions from the state. The long-term strategy must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress, as determined pursuant to [40 CFR § 51.308(f)(2)(i) through (iv)]." [168]

8.2 Measures Necessary to Make Reasonable Progress

As required by the Regional Haze Rule, NMED evaluated the emission reduction measures that are necessary to make reasonable progress toward natural visibility conditions in Class I Areas in New Mexico, as well as in Class I Areas outside New Mexico that may be affected by emissions from New Mexico, considering the four statutory factors described in 40 CFR § 51.308(f)(2)(i). Chapter 7 of this Regional Haze SIPr Rd 2 (2019-2028) provides a summary of NMED's four-factor analyses and reasonable progress control measures determinations for all units selected for analysis in the second planning period.

NMED initially identified 133 units requiring an analysis of potential control measures for NO_X and/or SO_2 in the second planning period. These include two-stroke lean burn engines (2SLB RICE), four-stroke lean burn engines (4SLB RICE), four-stroke rich burn engines (4SRB RICE), combustion turbines (CT), industrial and utility boilers, and amine treatment systems (ATS). However, after NMED completed its source screening, four facilities permanently shut down and several more retired one or more emissions units NMED had originally selected for analysis. NMED also identified a number of units that are already effectively controlled (for reasons other than retirement) or that did not require an analysis of potential control measures for other reasons. This left 91 units requiring a four-factor analysis. Of these, NMED identified 50 units with cost effective controls based on its $10,000/ton cost effectiveness threshold value. Applying the decision-making approach described in Section 7.4, NMED determined that reasonable progress requires new controls on all of these units.

8.2.1 Emissions limitations and compliance deadlines

As discussed in Section 7.4.3, NMED's reasonable progress control measures determinations are not prescriptive. Instead of mandating the installation of specific controls, NMED is imposing new emissions limitations in this Regional Haze SIPr Rd 2 (2019-2028) commensurate with controls deemed necessary for reasonable progress and leaving it up to facilities to determine how to comply. This approach is intended to give facilities the flexibility to consider factors beyond the four statutory factors considered by NMED when deciding how to comply with Regional Haze requirements. NMED is also establishing compliance deadlines for the installation of reasonable progress controls (or equivalent alternatives) to ensure facilities come into compliance before the end of the second planning period. Emissions limitations and compliance deadlines for the 50 units for which NMED identified reasonable progress controls are summarized in Table 8-1.

[168] 40 CFR § 51.308(f)(2).

Table 8-1. Emissions Limitations and Compliance Deadlines for Reasonable Progress Controls.

Facility	AI No.	Unit No.	Source Type	Reasonable Progress Control	NO_X Emission Limitation	Compliance Deadline [1]
Blanco Compressor Station A	1147	A11	2SLB RICE	Replacement w/ New RICE	0.5 g/bhp-hr	3 years
Blanco Compressor Station A	1147	A13	2SLB RICE	Replacement w/ New RICE	0.5 g/bhp-hr	3 years
Blanco C&D Compressor Station	3552	T-C01	CT	Selective Catalytic Reduction	13.04 lb/hr [2]	3 years
Blanco C&D Compressor Station	3552	T-C02	CT	Selective Catalytic Reduction	13.32 lb/hr [3]	3 years
Blanco C&D Compressor Station	3552	T-D01	CT	Selective Catalytic Reduction	24.22 lb/hr [4]	3 years
Chaco Gas Plant	1148	14	2SLB RICE	Low-Emission Combustion	0.5 g/bhp-hr	2 years
Cunningham Station Power Plant	604	1	Boiler	Selective Catalytic Reduction	12.07 lb/hr [5]	3 years
Cunningham Station Power Plant	604	2	Boiler	Selective Catalytic Reduction	30.05 lb/hr [6]	3 years
Eunice Gas Processing Plant	609	B-01	Boiler	Low NO_X Burners	9 ppmvd @ 3% O_2	2 years
Eunice Gas Processing Plant	609	B-02	Boiler	Low NO_X Burners	9 ppmvd @ 3% O_2	2 years
Eunice Gas Processing Plant	609	C-01	2SLB RICE	Replacement w/ New RICE	0.5 g/bhp-hr	3 years
Eunice Gas Processing Plant	609	C-02	2SLB RICE	Replacement w/ New RICE	0.5 g/bhp-hr	3 years
Eunice Gas Processing Plant	609	C-03	2SLB RICE	Replacement w/ New RICE	0.5 g/bhp-hr	3 years
Eunice Gas Processing Plant	609	C-04	2SLB RICE	Replacement w/ New RICE	0.5 g/bhp-hr	3 years
Eunice Gas Processing Plant	609	C-05	2SLB RICE	Replacement w/ New RICE	0.5 g/bhp-hr	3 years
Eunice Gas Processing Plant	609	C-06	2SLB RICE	Replacement w/ New RICE	0.5 g/bhp-hr	3 years
Eunice Gas Processing Plant	609	C-07	2SLB RICE	Replacement w/ New RICE	0.5 g/bhp-hr	3 years
Indian Basin Gas Plant	197	ES 06/07	CT	Dry Low NO_X Combustion	25 ppmvd @ 15% O_2	2 years
Indian Basin Gas Plant	197	ES 08/09	CT	Dry Low NO_X Combustion	25 ppmvd @ 15% O_2	2 years
Indian Basin Gas Plant	197	ES 10/11	CT	Dry Low NO_X Combustion	25 ppmvd @ 15% O_2	2 years
Kutz Canyon Processing Plant	1158	1	CT	Selective Catalytic Reduction	3.34 lb/hr [7]	3 years
Kutz Canyon Processing Plant	1158	2	CT	Selective Catalytic Reduction	3.54 lb/hr [8]	3 years
Kutz Canyon Processing Plant	1158	4	CT	Selective Catalytic Reduction	2.82 lb/hr [9]	3 years
Kutz Canyon Processing Plant	1158	5	CT	Selective Catalytic Reduction	2.38 lb/ hr [10]	3 years
Kutz Canyon Processing Plant	1158	6	CT	Selective Catalytic Reduction	2.36 lb/hr [11]	3 years
Kutz Canyon Processing Plant	1158	19	CT	Selective Catalytic Reduction	3.12 lb/hr [12]	3 years
Kutz Canyon Processing Plant	1158	20	CT	Selective Catalytic Reduction	3.12 lb/hr [13]	3 years
Monument Gas Plant	610	C-01	2SLB RICE	Replacement w/ New RICE	0.5 g/bhp-hr	3 years

Facility	AI No.	Unit No.	Source Type	Reasonable Progress Control	NO_X Emission Limitation	Compliance Deadline [1]
Monument Gas Plant	610	C-02	2SLB RICE	Replacement w/ New RICE	0.5 g/bhp-hr	3 years
Monument Gas Plant	610	C-05	2SLB RICE	Replacement w/ New RICE	0.5 g/bhp-hr	3 years
Monument Gas Plant	610	C-06	2SLB RICE	Replacement w/ New RICE	0.5 g/bhp-hr	3 years
Monument Gas Plant	610	C-24	2SLB RICE	Replacement w/ New RICE	0.5 g/bhp-hr	3 years
Mountainair Compressor Station No. 7	1569	701	4SLB RICE	Replacement w/ New CT	44.74 ton/yr [14]	3 years
Mountainair Compressor Station No. 7	1569	702	4SLB RICE			3 years
Mountainair Compressor Station No. 7	1569	703	4SLB RICE			3 years
Mountainair Compressor Station No. 7	1569	721	4SRB RICE	Replacement w/ Microturbine	9 ppmvd @ 15% O_2 [15]	3 years
Mountainair Compressor Station No. 7	1569	722	4SRB RICE	Replacement w/ Microturbine	9 ppmvd @ 15% O_2 [15]	3 years
Pecos River Compressor Station	194	A-02	CT	Selective Catalytic Reduction	7.28 lb/hr [16]	3 years
Pecos River Compressor Station	194	A-03	CT	Selective Catalytic Reduction	8.1 lb/hr [17]	3 years
Roswell Compressor Station No. 9	10	903	4SLB RICE	Replacement w/ New CT	29 ton/yr [18]	3 years
Roswell Compressor Station No. 9	10	904	4SLB RICE			3 years
San Juan Basin Gas Plant	1177	1	CT	Selective Catalytic Reduction	3.96 lb/hr [19]	3 years
San Juan Basin Gas Plant	1177	2	CT	Selective Catalytic Reduction	4.24 lb/hr [20]	3 years
San Juan Basin Gas Plant	1177	3	CT	Selective Catalytic Reduction	3.88 lb/hr [21]	3 years
San Juan Basin Gas Plant	1177	4	CT	Selective Catalytic Reduction	2.78 lb/hr [22]	3 years
San Juan Basin Gas Plant	1177	5	CT	Selective Catalytic Reduction	2.74 lb/hr [23]	3 years
San Juan Basin Gas Plant	1177	6	CT	Selective Catalytic Reduction	3.04 lb/hr [24]	3 years
San Juan Basin Gas Plant	1177	7	CT	Selective Catalytic Reduction	2.88 lb/hr [25]	3 years
South Carlsbad Compressor Station	218	1	CT	Dry Low NO_X Combustion	15 ppmvd @ 15% O_2	2 years
South Carlsbad Compressor Station	218	2	CT	Dry Low NO_X Combustion	15 ppmvd @ 15% O_2	2 years

[1] Compliance deadlines are expressed in years after final approval of this Regional Haze SIPr Rd 2 (2019-2028) by EPA.

[2] Emission limitation represents a 80% reduction from the current actual emission rate (65.2 lb/hr @ 100% load).

[3] Emission limitation represents a 80% reduction from the current actual emission rate (66.6 lb/hr @ 100% load).

[4] Emission limitation represents a 80% reduction from the current actual emission rate (121.1 lb/hr @ 100% load).

[5] Emission limitation represents a 90% reduction from the current actual emission rate (120.7 lb/hr @ 100% load). As noted in Section 7.5.23, this unit is not expected to operate beyond the end of the second planning period based on Xcel's current retirement schedule. The new limit is a backstop that only applies if service life is extended beyond 12/31/2028. Compliance with this emission limitation shall be determined on a 30-day rolling average basis.

[6] Emission limitation represents a 90% reduction from the current actual emission rate (300.5 lb/hr @ 100% load). As noted in Section 7.5.23, this unit is not expected to operate beyond the end of the second planning period based on Xcel's current retirement schedule. The new limit is a backstop that only applies if service life is extended beyond 12/31/2028. Compliance with this emission limitation shall be determined on a 30-day rolling average basis.

[7] Emission limitation represents a 80% reduction from the current actual emission rate (16.7 lb/hr @ 100% load).

[8] Emission limitation represents a 80% reduction from the current actual emission rate (17.7 lb/hr @ 100% load).
[9] Emission limitation represents a 80% reduction from the current actual emission rate (14.1 lb/hr @ 100% load). As noted in Section C.4.14 of Appendix C, the average adjusted emissions of identical Units 1-3 and Units 5-6 were used as a surrogate for Unit 4, as NMED was unable to locate a recent emissions test for report for this unit.
[10] Emission limitation represents a 80% reduction from the current actual emission rate (11.9 lb/hr @ 100% load).
[11] Emission limitation represents a 80% reduction from the current actual emission rate (11.8 lb/hr @ 100% load).
[12] Emission limitation represents a 80% reduction from the current actual emission rate (15.6 lb/hr @ 100% load). As noted in Section C.4.14 of Appendix C, the most recent testing of Units 19 and 20 was conducted at very low load. Therefore, instead of adjusting reported emissions to 100 percent load based on an assumed linear relationship between emissions and load, NMED used a surrogate emission factor based on the heat input capacity (MMBtu/hr) of these units and a vendor-provided emission rate expressed in lb/MMBtu.
[13] Emission limitation represents a 80% reduction from the current actual emission rate (15.6 lb/hr @ 100% load). As noted in Section C.4.14 of Appendix C, the most recent testing of Units 19 and 20 was conducted at very low load. Therefore, instead of adjusting reported emissions to 100 percent load based on an assumed linear relationship between emissions and load, NMED used a surrogate emission factor based on the heat input capacity (MMBtu/hr) of these units and a vendor-provided emission rate expressed in lb/MMBtu.
[14] 44.74 ton/yr is a multi-unit emission limitation applicable to Units 701, 702 and 703 combined. If TWP replaces these units with CT and the replacement ratio is not 1:1, the emission limitation will apply to all replacement units combined, regardless of their number. Compliance with this emission limitation shall be determined on a 12-month rolling sum basis.
[15] Based on manufacturer's specifications for Capstone C200 Microturbine.
[16] Emission limitation represents a 80% reduction from the current actual emission rate (36.4 lb/hr @ 100% load).
[17] Emission limitation represents a 80% reduction from the current actual emission rate (40.5 lb/hr @ 100% load).
[18] 29 ton/yr is a multi-unit emission limitation applicable to Units 903 and 904 combined. If TWP replaces these units with CT and the replacement ratio is not 1:1, the emission limitation will apply to all replacement units combined, regardless of their number. Compliance with this emission limitation shall be determined on a 12-month rolling sum basis.
[19] Emission limitation represents a 80% reduction from the current actual emission rate (19.8 lb/hr @ 100% load).
[20] Emission limitation represents a 80% reduction from the current actual emission rate (21.2 lb/hr @ 100% load).
[21] Emission limitation represents a 80% reduction from the current actual emission rate (19.4 lb/hr @ 100% load).
[22] Emission limitation represents a 80% reduction from the current actual emission rate (13.9 lb/hr @ 100% load).
[23] Emission limitation represents a 80% reduction from the current actual emission rate (13.7 lb/hr @ 100% load).
[24] Emission limitation represents a 80% reduction from the current actual emission rate (15.2 lb/hr @ 100% load).
[25] Emission limitation represents a 80% reduction from the current actual emission rate (14.4 lb/hr @ 100% load).

Emissions limitations for reasonable progress controls generally correspond to vendor-quoted, guaranteed post-control emission rates or, in the case of replacement, to the emission limits for new natural gas-fired spark ignition engines in 20.2.50 NMAC. Emissions limitations for selective catalytic reduction are based on current actual emissions and the assumed control efficiency (80% or 90%, depending on the unit).

To determine compliance deadlines, NMED assumed that facilities will begin working on project approval, budgeting and design while EPA approval of this Regional Haze SIPr Rd 2 (2019-2018) is still pending, shortening the time necessary for compliance once approval is granted. Therefore, for reasonable progress controls with an estimated compliance time of 2-3 years, NMED set the compliance deadline two (2) years after final approval of this SIPr by EPA. For reasonable progress controls with an estimated compliance time of 3-4 years, NMED set the compliance deadline three (3) years after final approval of this SIPr by EPA. Assuming this SIPr is approved by EPA by December 31, 2025, these deadlines will ensure that all reasonable progress controls are installed by the end of the second planning period.

To make the emissions limitations and compliance deadlines in Table 8-1 federally enforceable, NMED has included them in a proposed rule, 20.2.68 NMAC, which will be incorporated into this Regional Haze SIPr Rd 2 (2019-2028) following adoption of the rule and SIPr by the Environmental Improvement Board. A copy of the proposed rule, which also includes monitoring, recordkeeping, and reporting provisions to make the new emissions limitations practicably enforceable, is included in Appendix G.

8.2.2 Facility shutdowns and unit retirements

After NMED completed its source screening, four facilities permanently shut down and several more retired one or more emissions units NMED had originally selected for analysis. These actions resulted in the permanent retirement of 34 units selected for an analysis of potential control measures for NO_X and/or SO_2 in the second planning period. Because there is no more effective control than retirement, which reduces emissions by 100 percent, NMED determined that these units are effectively controlled by virtue of their retirement and forwent a four-factor analysis. The units in question have all been removed from their respective construction permits or the permits have been closed altogether, obviating the need for emissions limitations and compliance deadlines. Table 8.2 lists all retired units and the date they were removed from their respective construction permits or the permits were closed. Proposed rule 20.2.68 NMAC prohibits NMED from reauthorizing any of these units as a regulated emission source in any future construction permit modification issued by the department without a new analysis of the emission control measures necessary to make reasonable progress and an EPA-approved revision of this Regional Haze SIPr Rd 2 (2019-2028).

Table 8-2. Retired Units and Retirement Mechanism/Date.

Facility	AI No.	Unit No.	Source Type	Retirement Mechanism	Permit No.	Date
Denton Gas Plant	568	Varies (1)	ATS	Permit Closed	0065-M8	Feb. 4, 2022
Eunice Gas Plant	595	17A	CT	Permit Closed	0044-M11R1	Nov. 5, 2021
Eunice Gas Plant	595	18B	CT	Permit Closed	0044-M11R1	Nov. 5, 2021
Eunice Gas Plant	595	19A	CT	Permit Closed	0044-M11R1	Nov. 5, 2021
Eunice Gas Plant	595	25A	CT	Permit Closed	0044-M11R1	Nov. 5, 2021
Eunice Gas Plant	595	26A	CT	Permit Closed	0044-M11R1	Nov. 5, 2021
Eunice Gas Plant	595	Varies (2)	ATS	Permit Closed	0044-M11R1	Nov. 5, 2021
Eunice Gas Processing Plant	609	C-08	2SLB RICE	Removed From Permit	0067-M11R12	Aug. 20, 2024
Eunice Gas Processing Plant	609	C-09	2SLB RICE	Removed From Permit	0067-M11R9	May 31, 2024
Eunice Gas Processing Plant	609	C-10	2SLB RICE	Removed From Permit	0067-M11R9	May 31, 2024
Eunice Gas Processing Plant	609	C-11	2SLB RICE	Removed From Permit	0067-M11R9	May 31, 2024
Eunice Gas Processing Plant	609	C-12	2SLB RICE	Removed From Permit	0067-M11R9	May 31, 2024
Eunice Gas Processing Plant	609	C-13	2SLB RICE	Removed From Permit	0067-M11R9	May 31, 2024
Jal #3 Gas Plant	569	4A	2SLB RICE	Removed From Permit	1092-M10	Nov. 7, 2022
Jal #3 Gas Plant	569	5A	2SLB RICE	Removed From Permit	1092-M10	Nov. 7, 2022
Kutz Canyon Processing Plant	1158	16	2SLB RICE	Removed From Permit	0301-M11R2	May 11, 2021
Kutz Canyon Processing Plant	1158	17	2SLB RICE	Removed From Permit	0301-M11R2	May 11, 2021
Kutz Canyon Processing Plant	1158	18	2SLB RICE	Removed From Permit	0301-M11R2	May 11, 2021
Prewitt Escalante Generating Station	911	S111	Boiler	Removed From Permit	0285-M5	June 16, 2021
San Juan Generating Station	1421	S301/E301	Boiler	Permit Closed	0063-M12R3	Dec. 27, 2022
San Juan Generating Station	1421	S304/E304	Boiler	Permit Closed	0063-M12R3	Dec. 27, 2022
Saunders Gas Plant	612	C-01	2SLB RICE	Removed From Permit	0315-M5R2	May 31, 2024
Saunders Gas Plant	612	C-02	2SLB RICE	Removed From Permit	0315-M5R2	May 31, 2024
Saunders Gas Plant	612	C-03	2SLB RICE	Removed From Permit	0315-M5R2	May 31, 2024
Saunders Gas Plant	612	C-04	2SLB RICE	Removed From Permit	0315-M5R2	May 31, 2024
Saunders Gas Plant	612	C-05	2SLB RICE	Removed From Permit	0315-M5R2	May 31, 2024
Saunders Gas Plant	612	C-06	2SLB RICE	Removed From Permit	0315-M5R2	May 31, 2024
Saunders Gas Plant	612	C-07	2SLB RICE	Removed From Permit	0315-M5R2	May 31, 2024

Facility	AI No.	Unit No.	Source Type	Retirement Mechanism	Permit No.	Date
Saunders Gas Plant	612	C-08	2SLB RICE	Removed From Permit	0315-M5R2	May 31, 2024
Saunders Gas Plant	612	C-09	2SLB RICE	Removed From Permit	0315-M5R2	May 31, 2024
Saunders Gas Plant	612	G-01	4SRB RICE	Removed From Permit	0315-M5R2	May 31, 2024
Saunders Gas Plant	612	G-02	4SRB RICE	Removed From Permit	0315-M5R2	May 31, 2024
Saunders Gas Plant	612	G-03	4SRB RICE	Removed From Permit	0315-M5R2	May 31, 2024
Saunders Gas Plant	612	Varies [3]	ATS	Removed From Permit	0315-M5R2	May 31, 2024

[1] The ATS at Denton Gas Plant comprised Units 005 and 007.
[2] The ATS at Eunice Gas Plant comprised Units Amine-01, 31, 111, and 113.
[3] The ATS at Saunders Gas Plant comprised Units A-01, F-01, F-03, and I-01.

8.2.3 In-place emission controls

NMED determined that a number of emissions units evaluated for reasonable progress controls are already effectively controlled by in-place emission controls. These include Units 29, 30, 31, and 32B at DCP Operating Company's Linam Ranch Gas Plant, which are equipped with DLN; [169] Units 1 and 2 at El Paso Natural Gas Company's Washington Ranch Storage Facility, which are equipped with LEC; and Units C-891 and C-893 at IACX Roswell's Bitter Lake Compression Station, which are also equipped with LEC. The current, controlled emission rates for these units are significantly lower than emission rates for comparable units at other facilities without any controls. This was a major, if not the deciding factor in the outcome of NMED's four-factor analyses for these units. Therefore, the in-place controls on these units are necessary for reasonable progress, and NMED is imposing new emissions limitations in this Regional Haze SIPr Rd 2 (2019-2028) to ensure their continued use. The new limits for these units are listed in Table 8-3 and included in proposed rule 20.2.68 NMAC to make them federally enforceable.

Table 8-3. New Emissions Limitations for Units With In-Place Controls Necessary for Reasonable Progress.

Facility	AI No.	Unit No.	Source Type	NO_X Emission Limitation
Bitter Lake Compressor Station	14	C-891	2SLB RICE	3.0 g/bhp-hr
Bitter Lake Compressor Station	14	C-893	2SLB RICE	3.0 g/bhp-hr
Linam Ranch Gas Plant	589	29	CT	15 ppmvd @ 15% O_2
Linam Ranch Gas Plant	589	30	CT	25 ppmvd @ 15% O_2
Linam Ranch Gas Plant	589	31	CT	25 ppmvd @ 15% O_2
Linam Ranch Gas Plant	589	32B	CT	25 ppmvd @ 15% O_2
Washington Ranch Storage Facility	220	1	2SLB RICE	3.0 g/bhp-hr
Washington Ranch Storage Facility	220	2	2SLB RICE	3.0 g/bhp-hr

NMED also determined that the amine treatment systems at several facilities are effectively controlled by in-place emission controls, specifically, acid gas injection (AGI) wells with redundant compression. These include DCP Operating Company's Linam Ranch Gas Plant, ET Gathering & Processing's Jal #3 Gas Plant, and Targa Midstream Services' Eunice Gas Processing Plant and Monument Gas Plant. The NSR permits for these facilities include conditions requiring that all emissions from their respective amine treatment units be routed to the AGI well at all times (except during authorized SSM and malfunction flaring events) and not emitted directly to the atmosphere, that a backup compressor be operationally available to inject acid gas into the AGI well at all times, and that the backup compressor have sufficient capacity to accept the entire acid gas stream during maintenance or failure of the primary compressor. Because these in-place controls are necessary for reasonable progress, NMED is incorporating NSR permit conditions pertaining to them into this Regional Haze SIPr Rd 2 (2019-2028) to ensure their continued use. Table 8-4 lists all incorporated NSR permit conditions pertaining to in-place controls necessary for reasonable progress.

[169] As noted in Section C.4.4 of Appendix C, DCP is in the advanced stages of upgrading Unit 32B with DLN to comply with 20.2.50 NMAC. Therefore, NMED's base case assumes DLN has already been installed on this unit, making it an in-place control for purposes of regional haze.

Table 8-4. Incorporated NSR Permit Conditions Pertaining to In-Place Controls Necessary for Reasonable Progress.

Facility	AI No.	Permit No.	Condition No.
Linam Ranch Gas Plant	589	39-M9	A208.A. Amine Unit Controls and Requirements for Acid Gas Injection (AGI) Well and AGI Compressors (Units AM-10, AGI Well, and two acid gas compressors, AGI-C1 and AGI-C2); and A208.B. Operation of Acid Gas Injection Well System (Unit Amine A-10, AGI Well, AGI Flare, and Flare Unit 2)
Jal #3 Gas Plant	569	1092-M10R3	A208.D. Requirements for Acid Gas Injection (AGI) Well and AGI Compressors (Units AGI, AGI-Compressors COMP-1 and COMP-2); and A208.E. Operation of Acid Gas Injection Well System (Units Amine-2, AGI)
Eunice Gas Processing Plant	609	0067-M11	A210.A. Requirements for Acid Gas Injection (AGI) Well and AGI Compressors (Units AGI, AGI-C1, AGI-C2); and A210.B. Operation of Acid Gas Injection Well System (Units AM-01, AGI)
Monument Gas Plant	610	110-M11R2	A210.A. AGI Operations (Unit AGI controlling AM-01)

8.3 Consideration of Additional Factors for Long-term Strategy

The Regional Haze Rule requires that NMED must consider the following additional factors in developing its long-term strategy: [170]

- Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
- Measures to mitigate the impacts of construction activities;
- Source retirement and replacement schedules;
- Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs; and
- The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

A description of how NMED considered these additional factors is provided in Sections 8.3.1 through 8.3.5.

[170] 40 CFR § 51.308(f)(2)(iv).

8.3.1 Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment

The Regional Haze Rule requires states to consider emission reductions due to ongoing air pollution control programs in their long-term strategies. These programs include new source performance standards, national emissions standards for hazardous air pollutants, national onroad and nonroad emissions standards, the cross-state air pollution rule, and other national rules that limit the emissions of pollutants that may contribute to visibility impairment. Emission reductions due to ongoing programs were considered through their incorporation into WRAP's projected 2028OTBa2 emissions inventory, which was used to model aerosol light extinction and develop Reasonable Progress Goals (RPGs) for New Mexico federal Class I Areas.

After WRAP compiled the projected 2028OTBa2 emissions inventory and completed its modeling analyses, New Mexico adopted a pair of rules that will further reduce emissions contributing to visibility impairment in New Mexico Class I Areas. The first, 20.2.50 NMAC – Oil and Gas Sector – Ozone Precursor Pollutants, is a state-only rule establishing emissions standards and other requirements applicable to certain crude oil and natural gas production and processing equipment in counties that exceed ninety-five percent of the national ambient air quality standard for ozone.[171] The second, 20.2.91 NMAC – New Motor Vehicle Emission Standards, adopts the latest California vehicle emission standards and requirements, including requirements pertaining to the delivery of an increasing percentage of zero-emission vehicles for sale in New Mexico. As discussed in Section 12.3, NMED has committed in this Regional Haze SIPr Rd 2 (2019-2028) to continue to submit annual inventories of pollutants, including those reasonably anticipated to cause or contribute to visibility impairment, pursuant to 40 CFR § 51.308(f)(6)(v). The emissions reductions due to these new rules will be captured in future inventories and considered in the next planning period.

8.3.2 Measures to mitigate the impact of construction activities

NMED did not select construction activities as a source category for an analysis of control measures for reasonable progress for the second planning period. As part of its process to select sources for four-factor analysis, NMED reviewed IMPROVE-based light extinction info for the most impaired days and clearest days, presented in Chapter 4. The IMPROVE-based light extinction budget for coarse mass indicates it comprises a smaller total contribution to extinction at New Mexico Class I Areas compared to ammonium sulfates and nitrates. NMED developed a strategy to look at the combined SO_2 and NO_X emissions, which are precursors to sulfates and nitrates, from major Title V point sources (See Chapter 6). NMED consulted with FLMs on this approach in 2019 and received a favorable response on its source selection methodology. Moreover, inventories in New Mexico for construction activities are not nearly as well developed as they are for larger point sources. NMED may choose to further evaluate construction activities in a future planning period.

8.3.3 Source retirement and replacement schedules

The Regional Haze Rule requires states to consider source retirement and replacement schedules in their long-term strategies. Similar to emission reductions due to ongoing air pollution control programs,

[171] Currently, 20.2.50 NMAC applies to sources in Chaves, Doña Ana, Eddy, Lea, Rio Arriba, Sandoval, San Juan, and Valencia Counties. These counties encompass the Permian and San Juan Basins, which are the primary oil and gas production regions in New Mexico.

known source retirement and replacement schedules were considered through their incorporation into WRAP's projected 2028OTBa2 emissions inventory, which was used to model aerosol light extinction and develop Reasonable Progress Goals (RPGs) for New Mexico federal Class I Areas. More recent retirements were considered as part of NMED's four-factor analyses and reasonable progress control measures determinations and are discussed in Section 8.2.2.

8.3.4 Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs

NMED administers a comprehensive Smoke Management Program (SMP) developed to meet the requirements of the Regional Haze Rule.[172] The SMP is applicable in all of New Mexico, excluding Tribal lands and Bernalillo County, which are separate air quality jurisdictions, and helps control prescribed fire-related emissions of VOCs, NO_X, elemental carbon, organic carbon, and $PM_{2.5}$. 20.2.65 NMAC – Smoke Management, provides the enforcement mechanism for the SMP and requires that most prescribed burning in New Mexico be conducted in accordance with rule requirements, including: the reporting of emissions for use in emissions inventories; consideration of alternatives to burning; use of enhanced smoke management techniques recommended by the WRAP; and use of specific emission reduction techniques.

8.3.5 Anticipated Net Effect on Visibility Due to Projected Changes in Point, Area, and Mobile Source Emissions Over the Period Addressed by the Long-term Strategy.

The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions is demonstrated through WRAP's modeling of U.S. anthropogenic contributions to aerosol light extinction for New Mexico federal Class I Areas. The results of this modeling are shown in Figure 8-1 through Figure 8-9. WRAP's modeling was conducted before NMED completed its four-factor analyses and therefore does not reflect expected emission reductions due to the reasonable progress control measures described in Section 8.2. As such, modeled U.S. anthropogenic contributions to aerosol light extinction for the 2028OTBa2 scenario are likely overstated.

[172] Information on NMED's Smoke Management Program is available at https://www.env.nm.gov/air-quality/smp/.

Figure 8-1 Estimated Anthropogenic Impact Changes, Bandelier Wilderness Area.

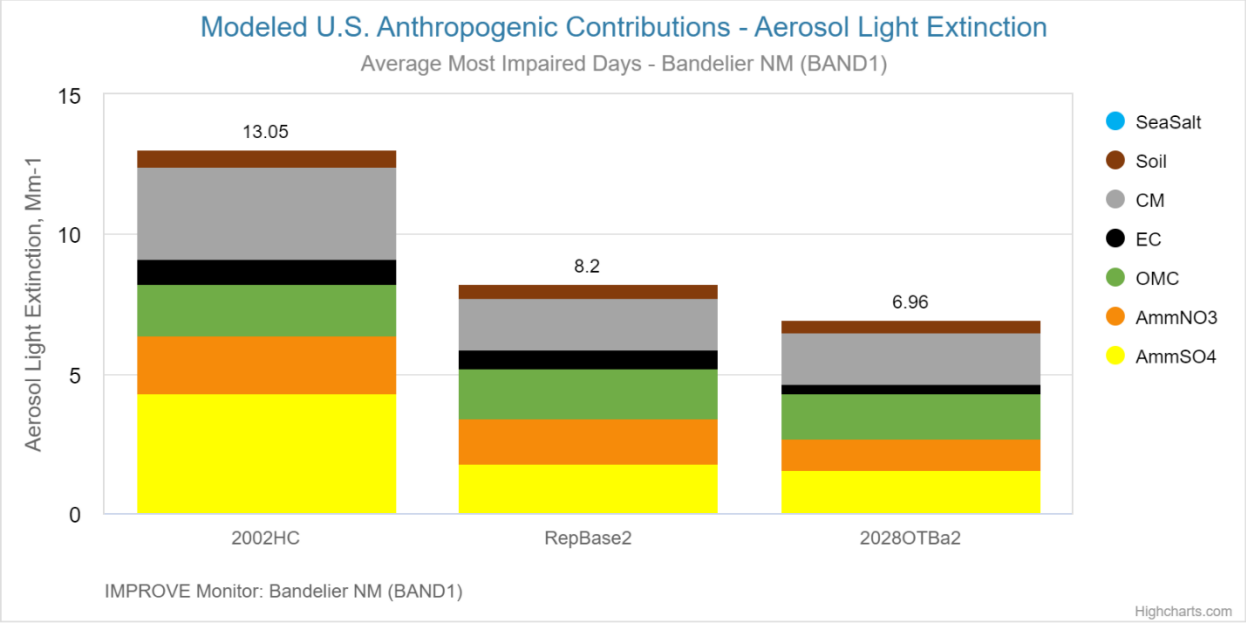


Figure 8-2 Estimated Anthropogenic Impact Changes, Bosque Del Apache Wilderness Area.

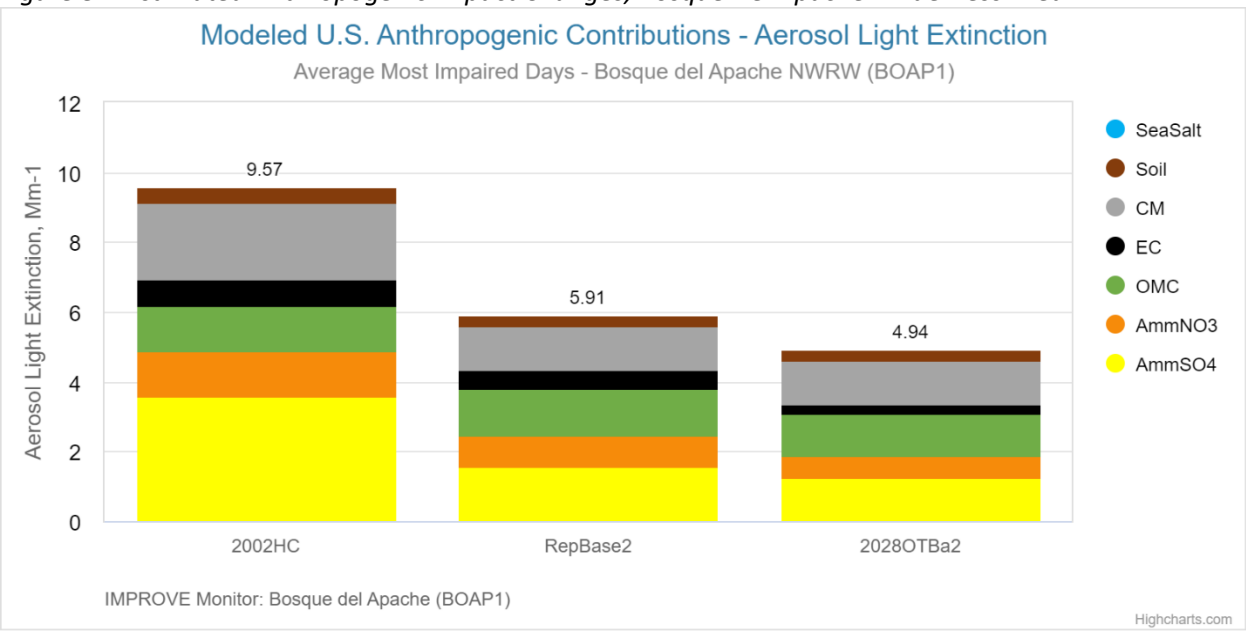


Figure 8-3 Estimated Anthropogenic Impact Changes, Carlsbad Caverns National Park.

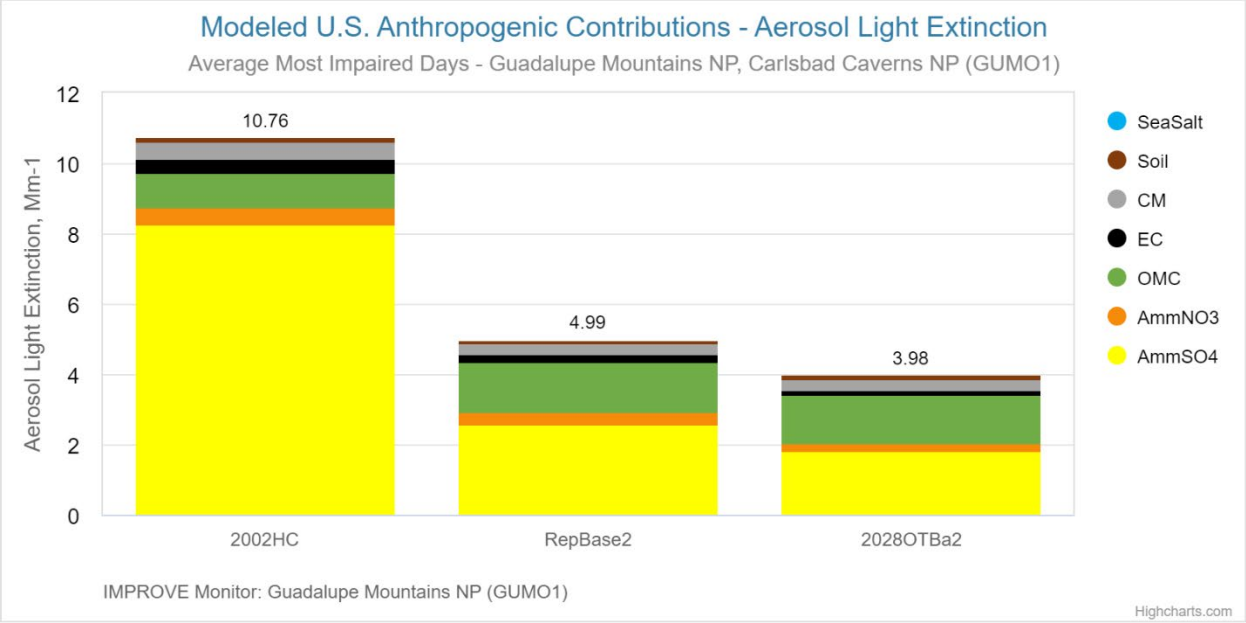


Figure 8-4 Estimated Anthropogenic Impact Changes, Gila Wilderness Area.

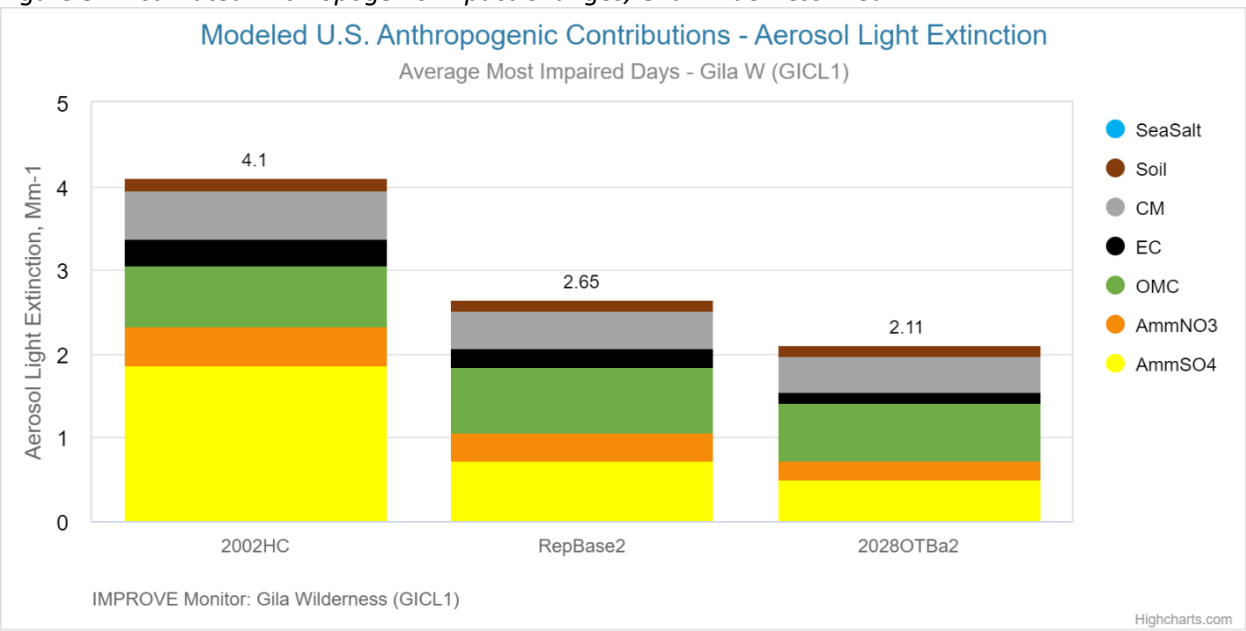


Figure 8-5 Estimated Anthropogenic Impact Changes, Pecos Wilderness Area.

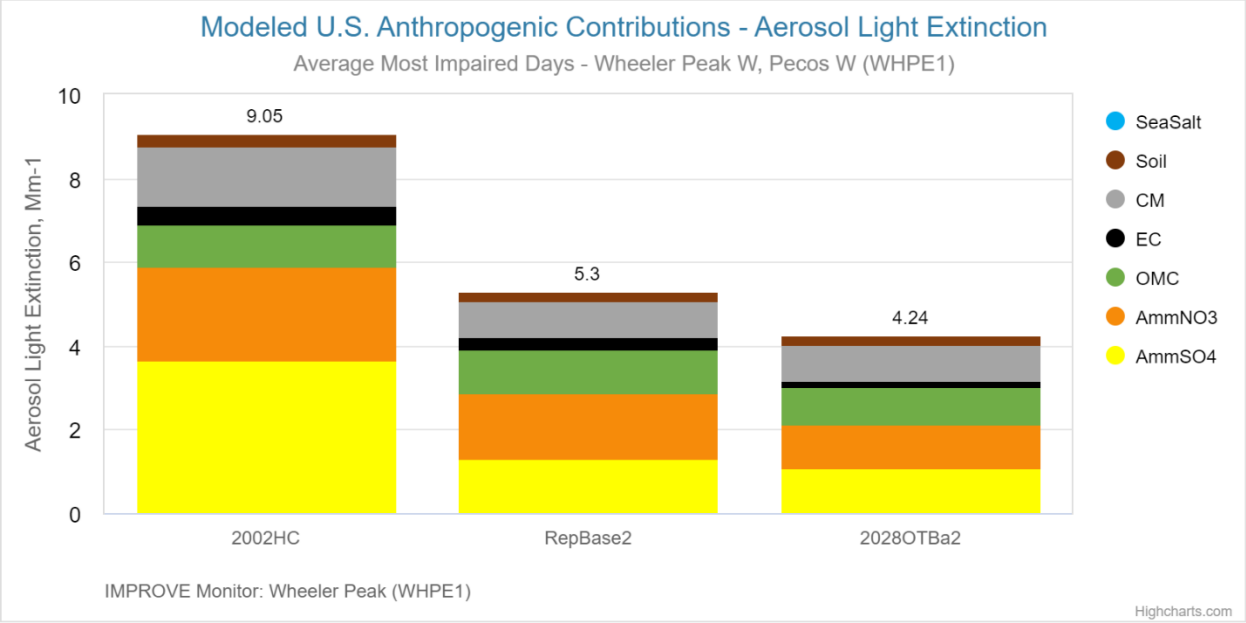


Figure 8-6 Estimated Anthropogenic Impact Changes, Salt Creek Wilderness Area.

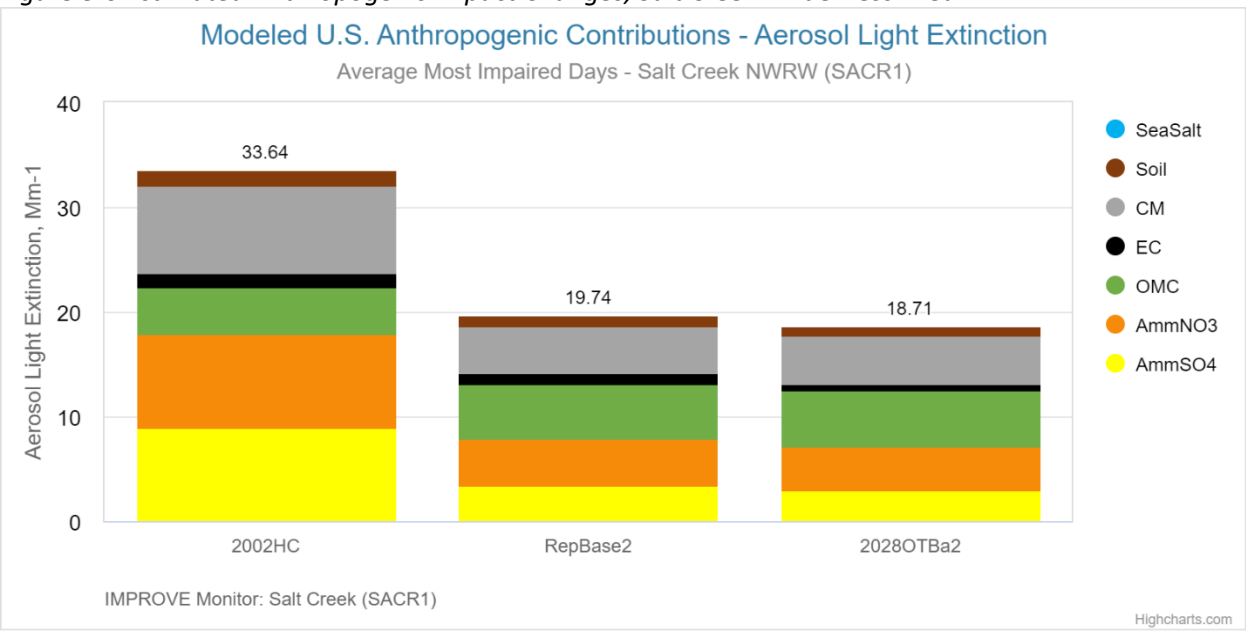


Figure 8-7 Estimated Anthropogenic Impact Changes, San Pedro Parks Wilderness Area.

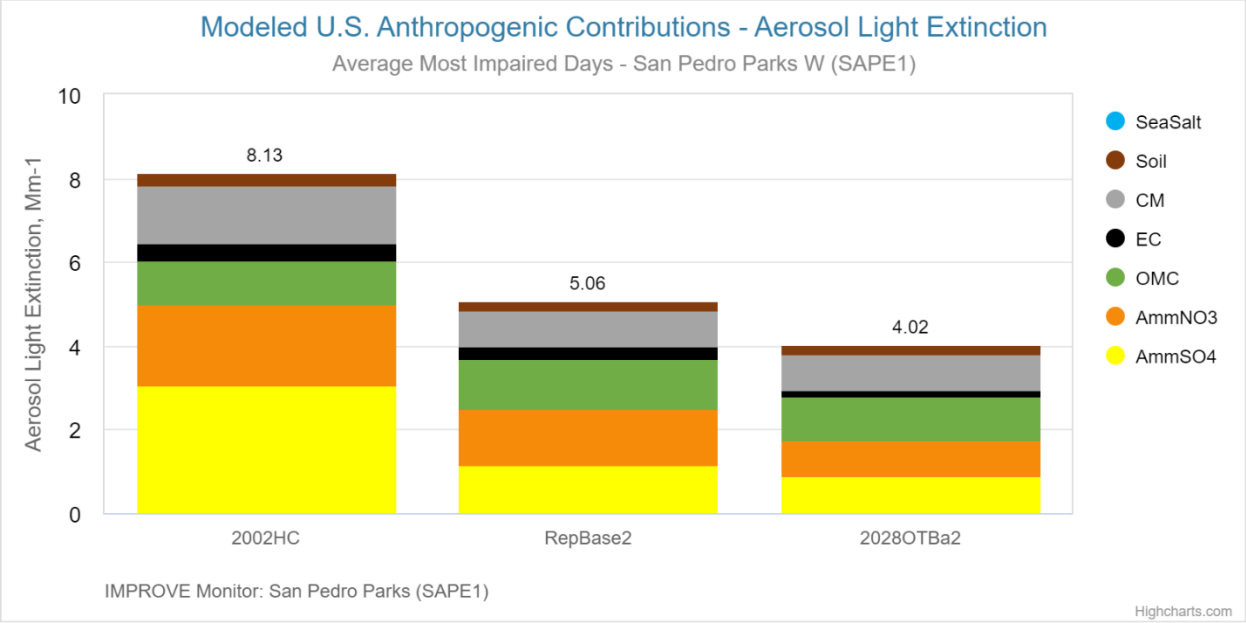


Figure 8-8 Estimated Anthropogenic Impact Changes, Wheeler Peak Wilderness Area.

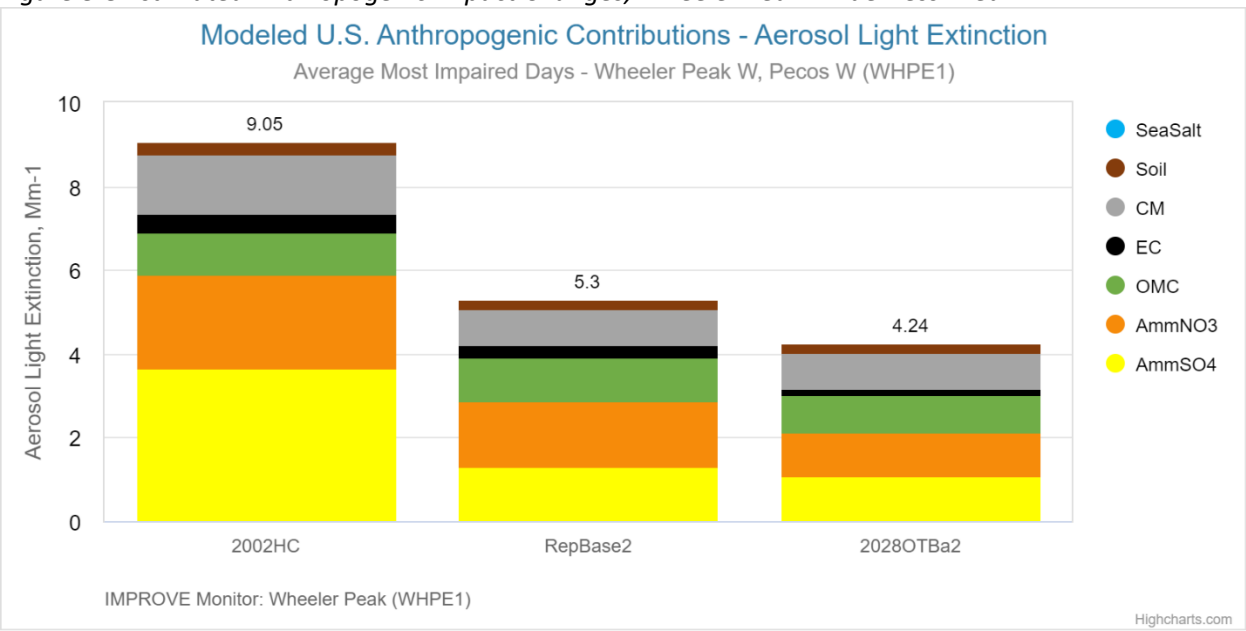
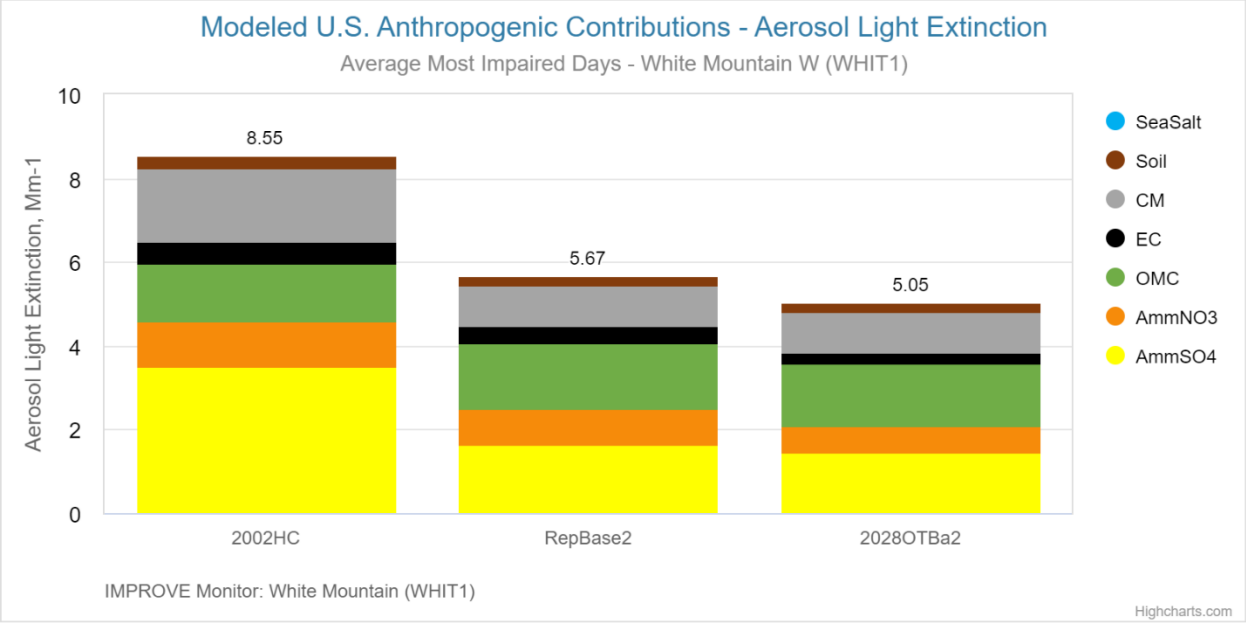


Figure 8-9 Estimated Anthropogenic Impact Changes, White Mountain Wilderness Area.



Chapter 9: Regional Scale Modeling to Set Reasonable Progress Goals for 2028

9.1 Regulatory Requirements

The Regional Haze Rule requires that states establish reasonable progress goals (expressed in deciviews) that reflect the visibility conditions that are projected to be achieved by the end of the implementation period as a result of the long-term strategy. [173]

9.2 Modeled Future Year Most Impaired Days for New Mexico Class I Areas

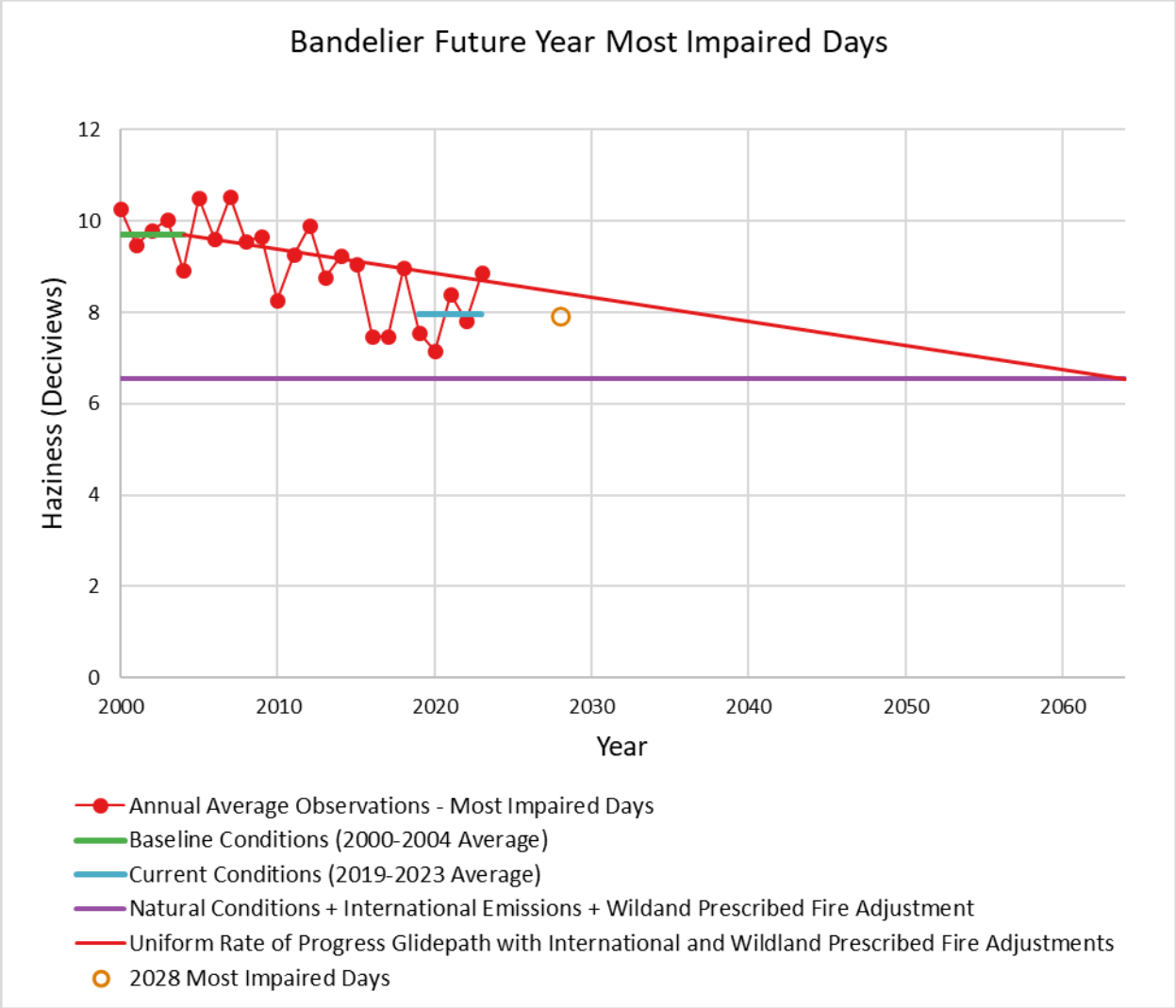
Sections 9.2.1 to 9.2.8 (and corresponding Figure 9-1 to Figure 9-8) illustrate the reasonable progress goals as modeled future year most impaired days (MID) for each Class I Area in New Mexico. Modeled future year MID are based on the Western Regional Air Partnership (WRAP) 2028 'On the Books' modeling scenario (2028OTBa2). [174] This modeling scenario includes regulations that were reported to WRAP as already adopted by regulatory agencies as of September 2020.

[173] 40 CFR 51.308(f)(3)(i)

[174] WRAP/Western Air Quality Modelling Study – Regional Haze Modeling Scenarios' Specification Sheets https://views.cira.colostate.edu/iwdw/docs/WAQS_and_WRAP_Regional_Haze_spec_sheets.aspx

9.2.1 Bandelier Wilderness Area

Figure 9-1: Reasonable Progress Goals for Bandelier Wilderness Area.

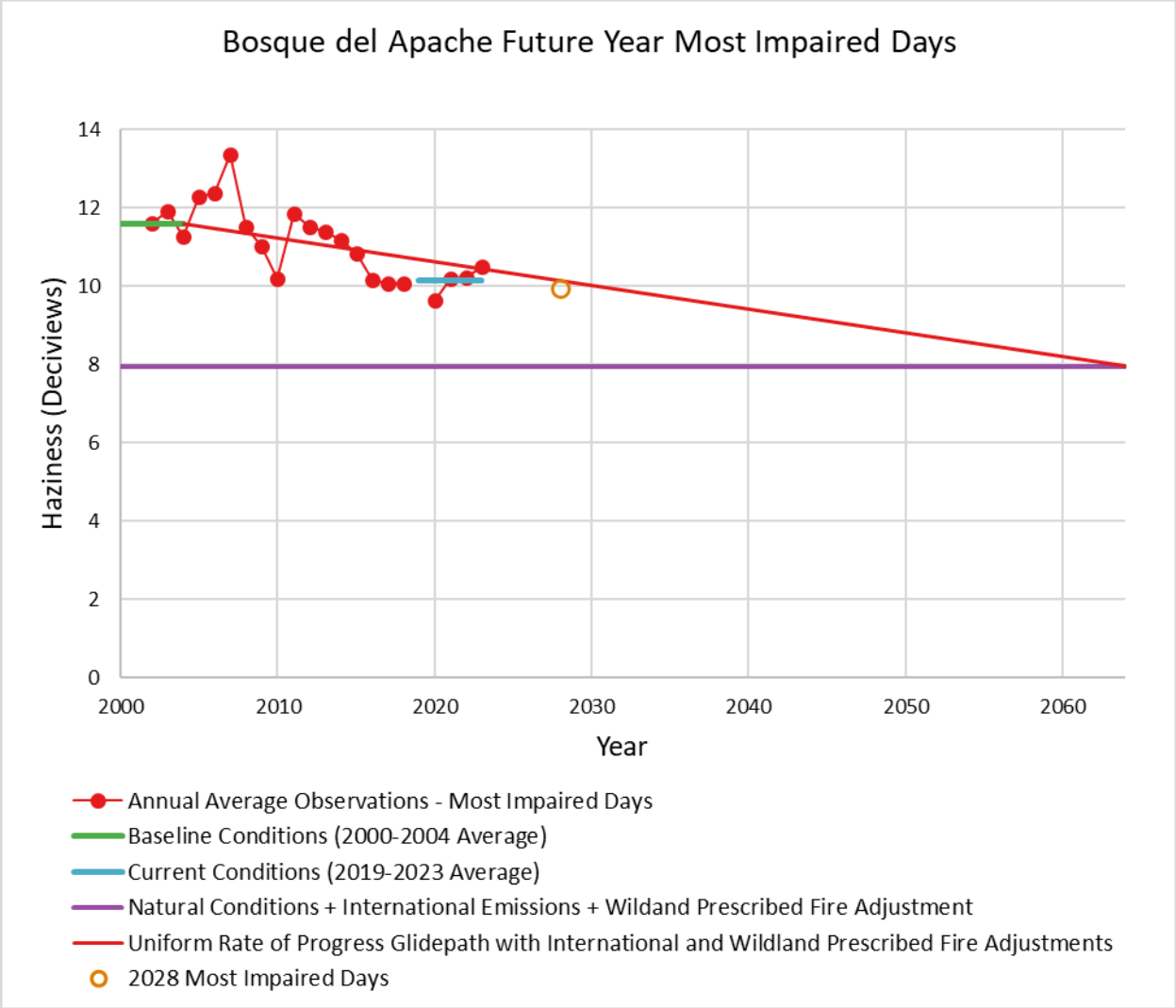


Values for BAND1:

	Deciviews
Baseline Conditions (2000-2004 Average)	9.7
Current Conditions (2019-2023 Average)	8.0
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	6.5
2028 Most Impaired Days (Modeled Reasonable Progress Goal)	7.9
2028 Point on URP Glidepath	8.4

9.2.2 Bosque del Apache Wilderness Area

Figure 9-2: Reasonable Progress Goals for Bosque del Apache Wilderness Area.

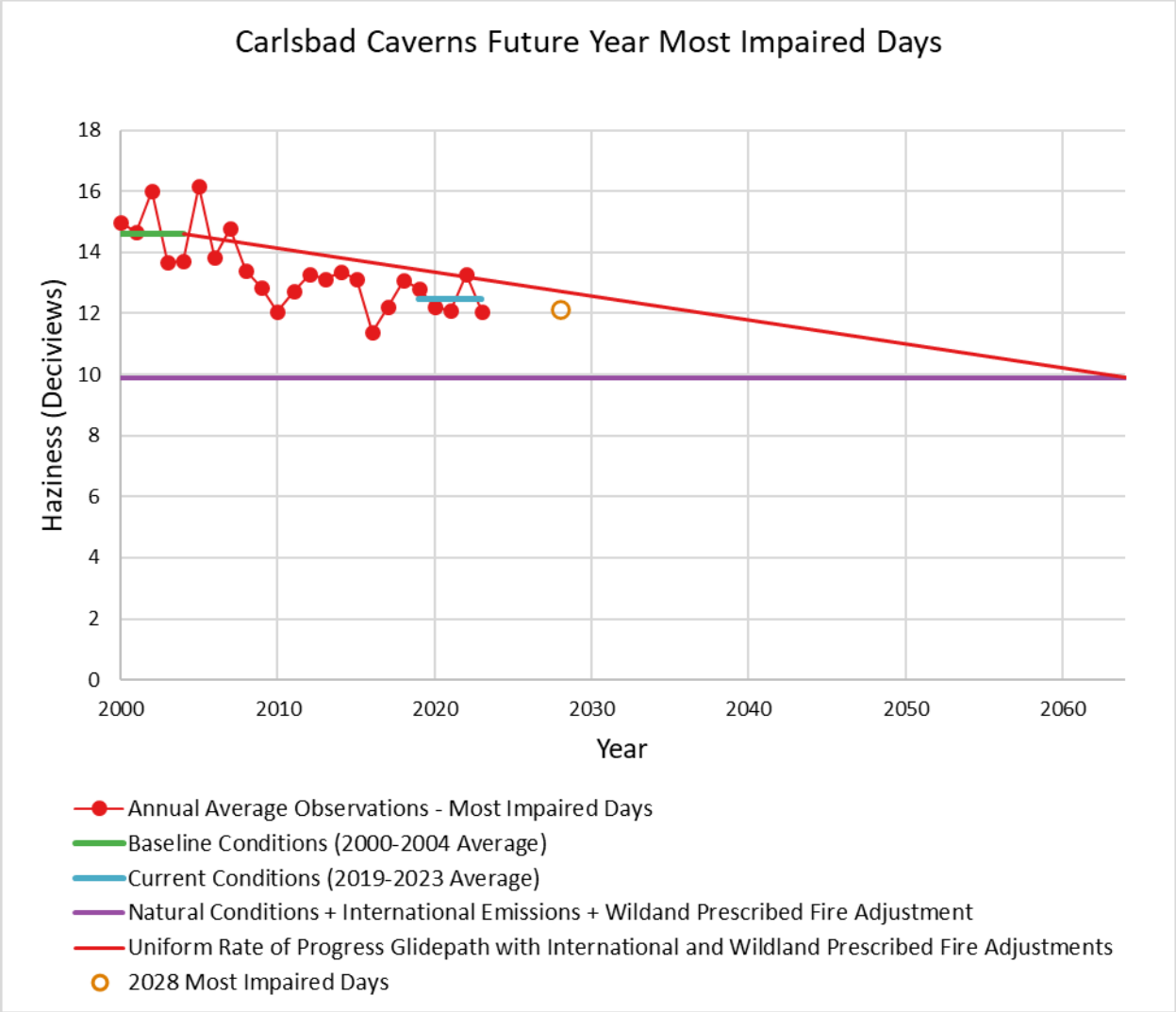


Values for BOAP1:

	Deciviews
Baseline Conditions (2000-2004 Average)	11.6
Current Conditions (2019-2023 Average)	10.1
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	8.0
2028 Most Impaired Days (Modeled Reasonable Progress Goal)	9.9
2028 Point on URP Glidepath	10.2

9.2.3 Carlsbad Caverns National Park

Figure 9-3: Reasonable Progress Goals for Carlsbad Caverns National Park.

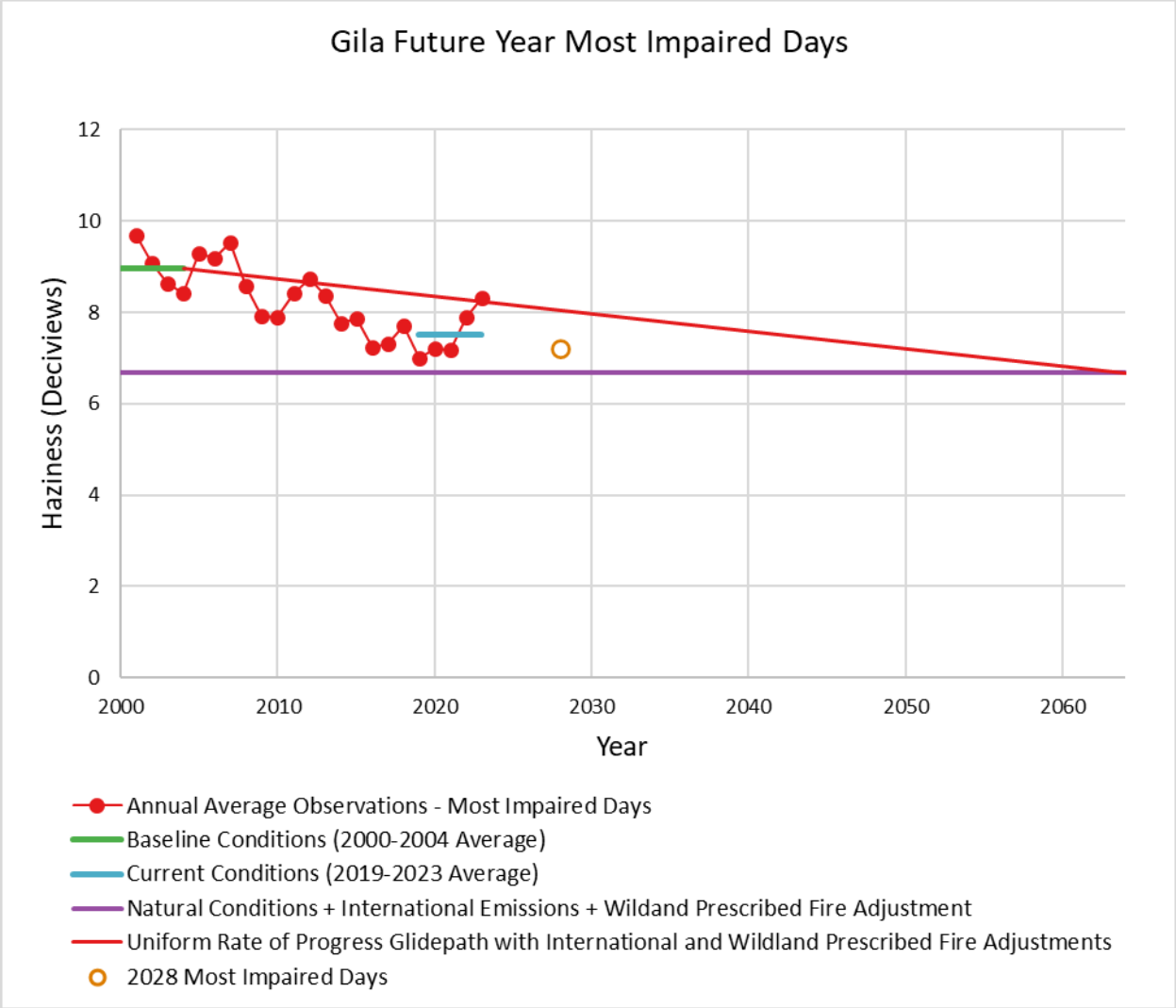


Values for GUMO1:

	Deciviews
Baseline Conditions (2000-2004 Average)	14.6
Current Conditions (2019-2023 Average)	12.5
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	9.9
2028 Most Impaired Days (Modeled Reasonable Progress Goal)	12.1
2028 Point on URP Glidepath	12.7

9.2.4 Gila Wilderness Area

Figure 9-4: Reasonable Progress Goals for Gila Wilderness Area.

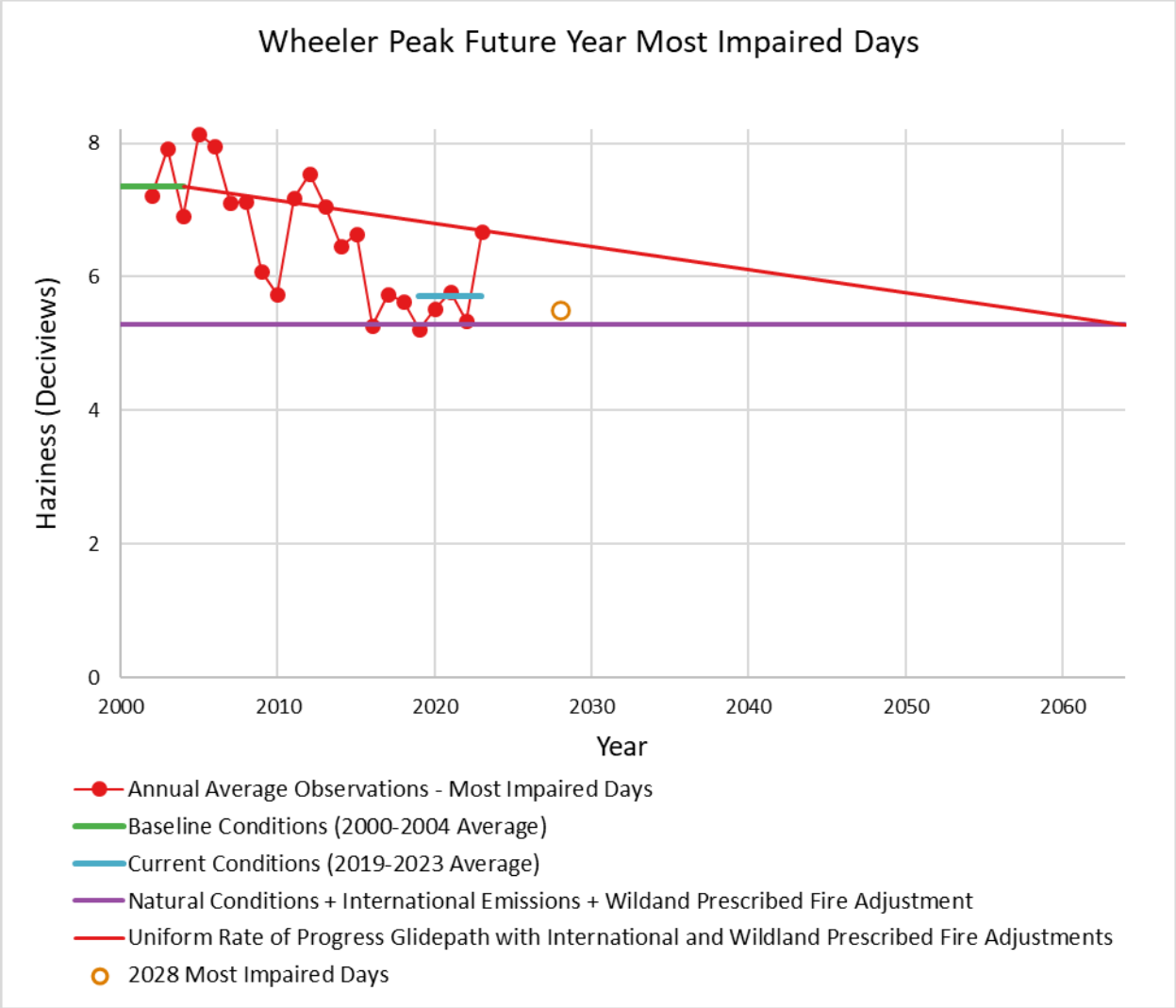


Values for GICL1:

	Deciviews
Baseline Conditions (2000-2004 Average)	9.0
Current Conditions (2019-2023 Average)	7.5
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	6.7
2028 Most Impaired Days (Modeled Reasonable Progress Goal)	7.2
2028 Point on URP Glidepath	8.1

9.2.5 Pecos Wilderness Area & Wheeler Peak Wilderness Area

Figure 9-5: Reasonable Progress Goals for Pecos and Wheeler Peak Wilderness Areas.

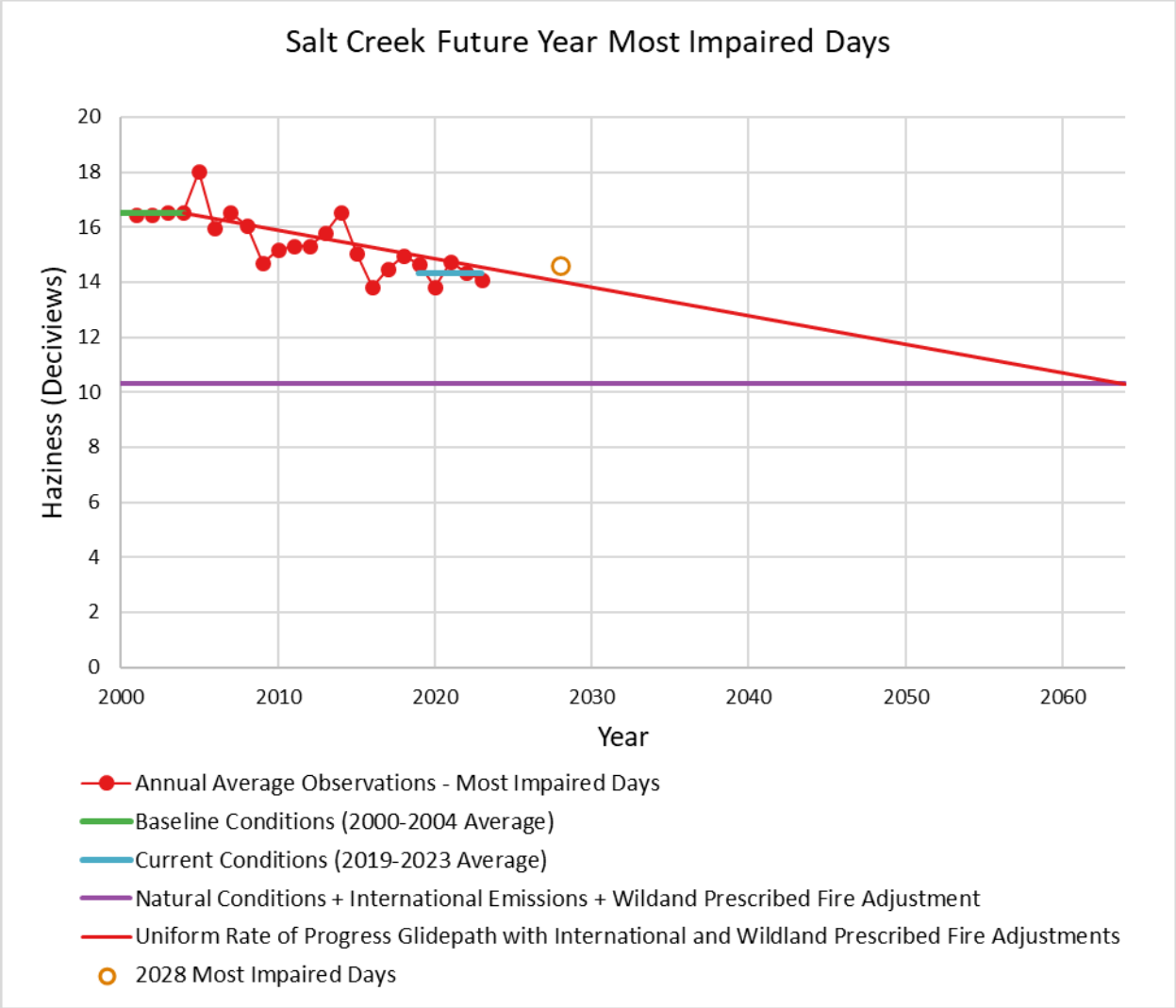


Values for WHPE1:

	Deciviews
Baseline Conditions (2000-2004 Average)	7.3
Current Conditions (2019-2023 Average)	5.7
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	5.3
2028 Most Impaired Days (Modeled Reasonable Progress Goal)	5.5
2028 Point on URP Glidepath	6.5

9.2.6 Salt Creek Wilderness Area

Figure 9-6: Reasonable Progress Goals for Salt Creek Wilderness Area.

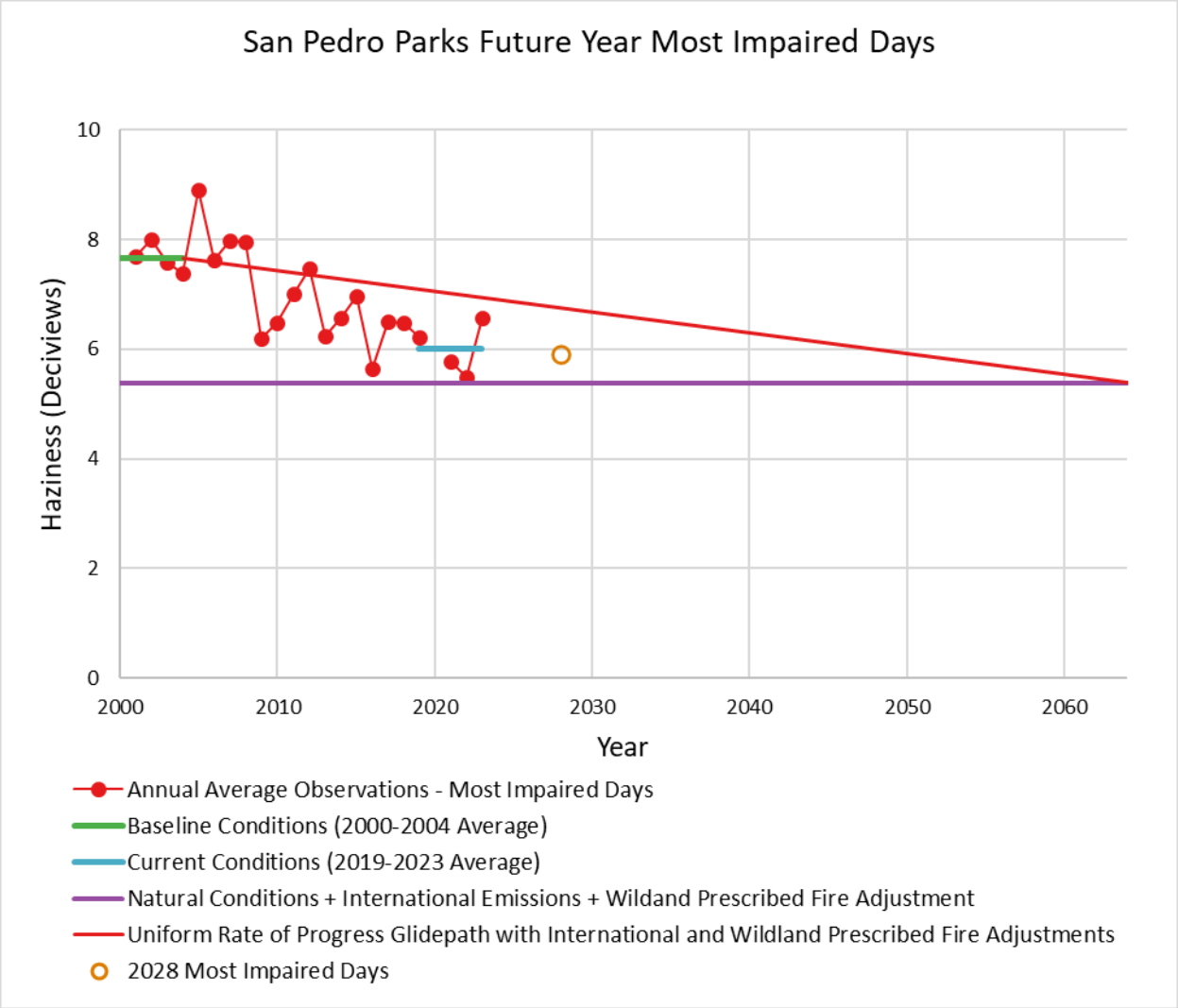


Values for SACR1:

	Deciviews
Baseline Conditions (2000-2004 Average)	16.5
Current Conditions (2019-2023 Average)	14.3
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	10.3
2028 Most Impaired Days (Modeled Reasonable Progress Goal)	14.6
2028 Point on URP Glidepath	14.0

9.2.7 San Pedro Parks Wilderness Area

Figure 9-7: Reasonable Progress Goals for San Pedro Parks Wilderness Area.

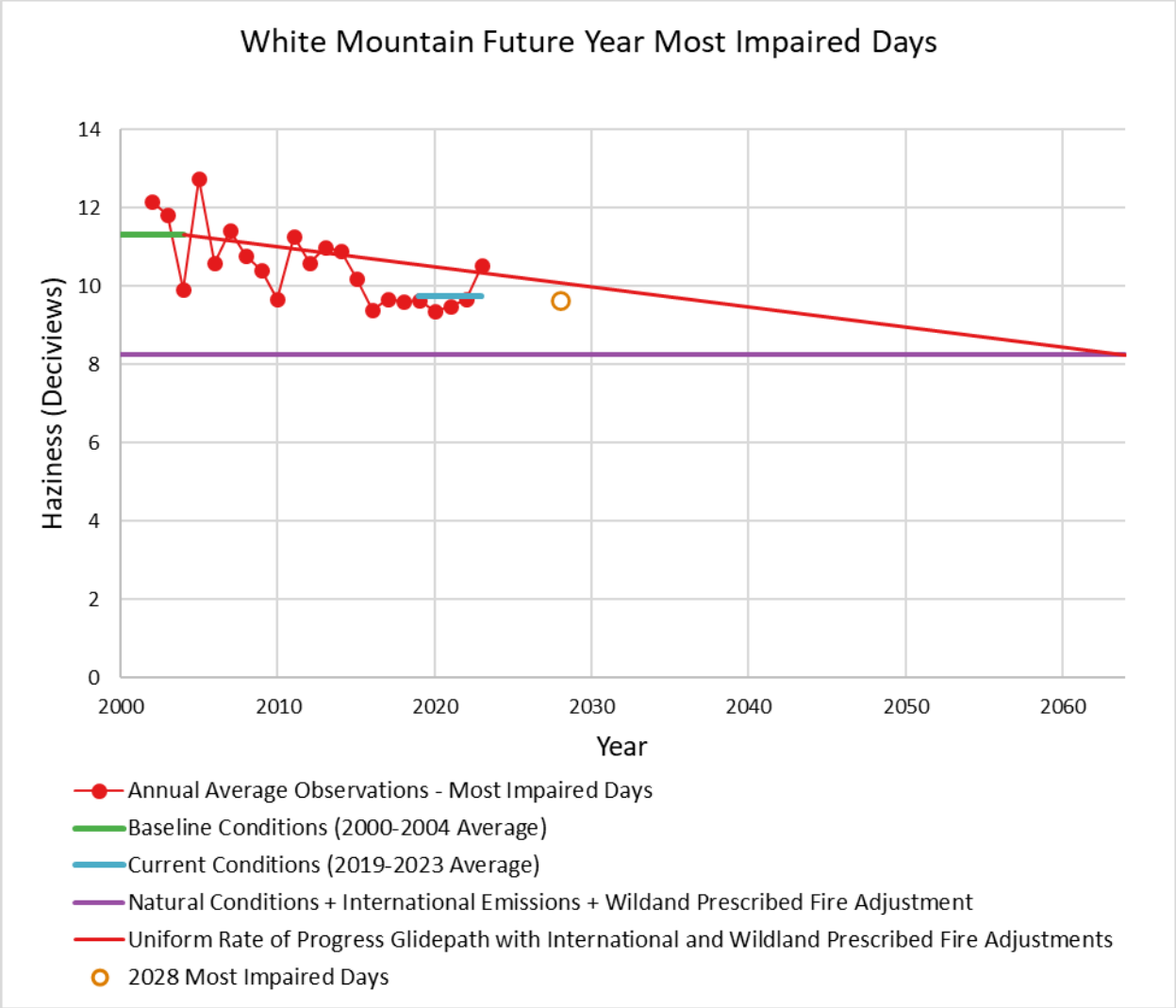


Values for SAPE1:

	Deciviews
Baseline Conditions (2000-2004 Average)	7.7
Current Conditions (2019-2023 Average)	6.0
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	5.4
2028 Most Impaired Days (Modeled Reasonable Progress Goal)	5.9
2028 Point on URP Glidepath	6.8

9.2.8 White Mountain Wilderness Area

Figure 9-8: Reasonable Progress Goals for White Mountain Wilderness Area.



Values for WHIT1:

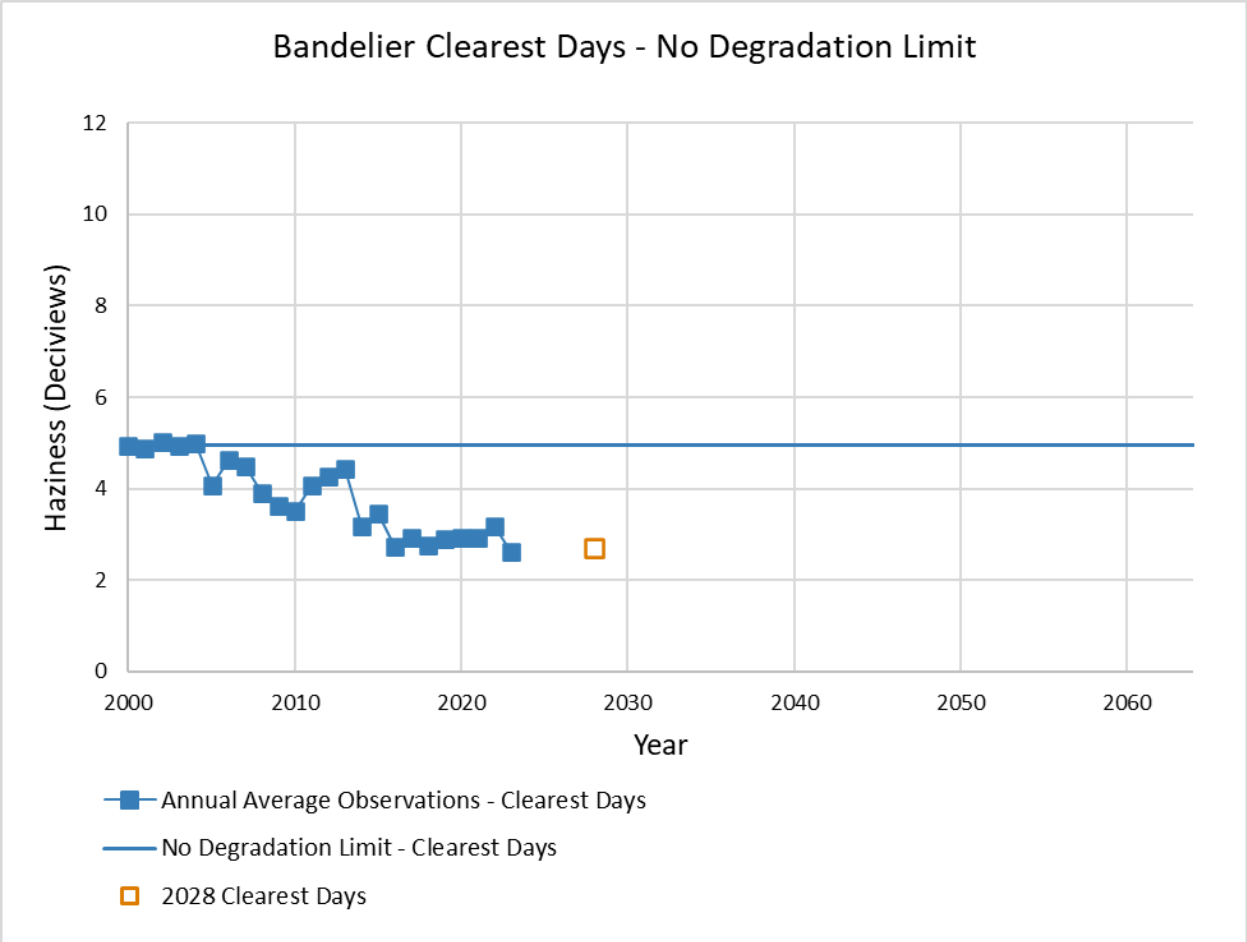
	Deciviews
Baseline Conditions (2000-2004 Average)	11.3
Current Conditions (2019-2023 Average)	9.7
Natural Conditions + International Emissions + Wildland Prescribed Fire Adjustment	8.3
2028 Most Impaired Days (Modeled Reasonable Progress Goal)	9.6
2028 Point on URP Glidepath	10.1

9.3 Modeled Future Year Clearest Days for New Mexico Class I Areas

Section 9.3 shows the reasonable progress goals as modeled future year clearest days for each Class I Area in New Mexico. Modeled future year clearest days are based on the WRAP 2028 'On the Books' modeling scenario (2028OTBa2).

9.3.1 Bandelier Wilderness Area

Figure 9-9: Future Year Clearest Days at Bandelier Wilderness Area.

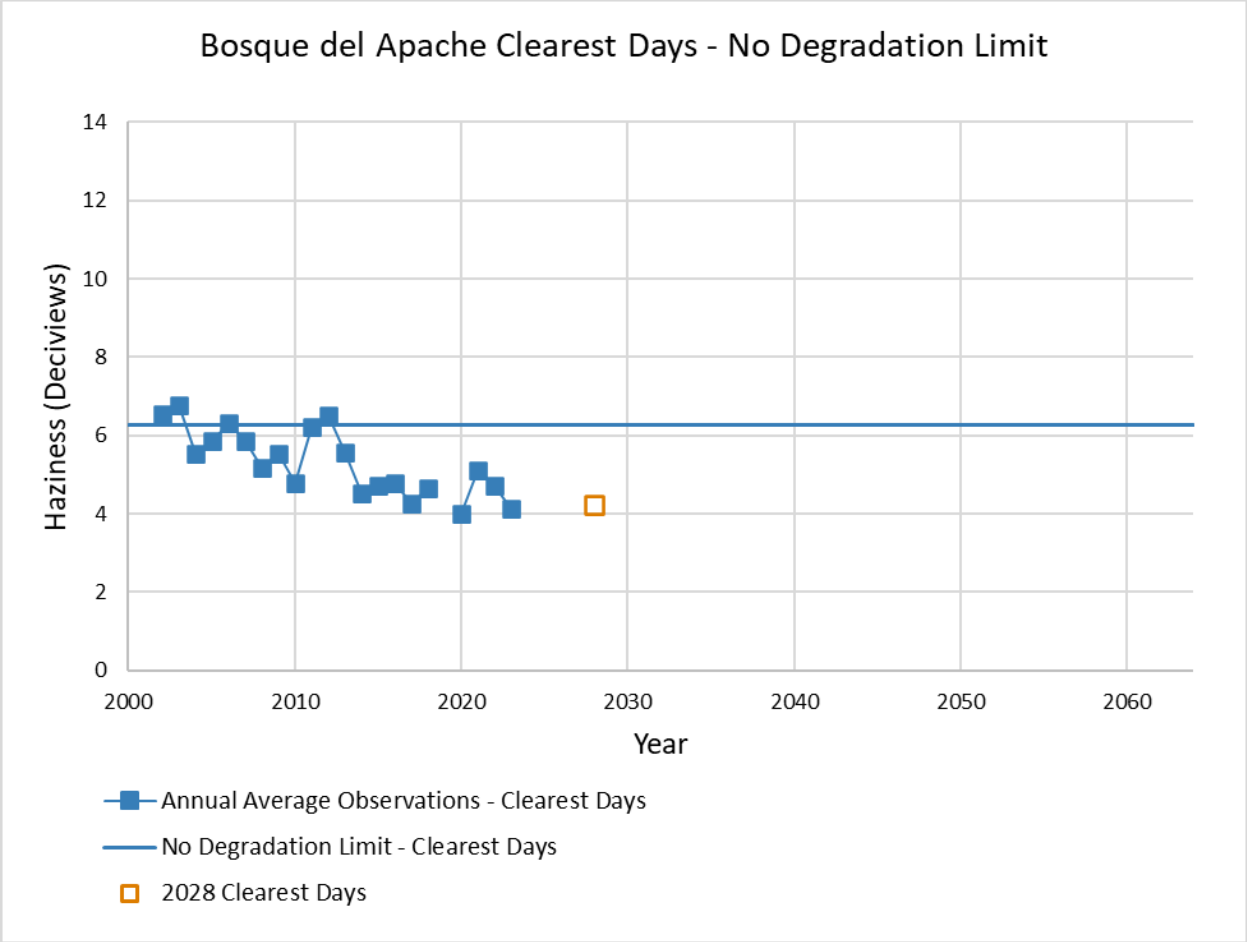


Values for BAND1:

	Deciviews
No Degradation Limit – Clearest Days	5.0
2028 Clearest Days (Modeled Reasonable Progress Goal)	2.7

9.3.2 Bosque del Apache Wilderness Area

Figure 9-10: Future Year Clearest Days at Bosque del Apache Wilderness Area.

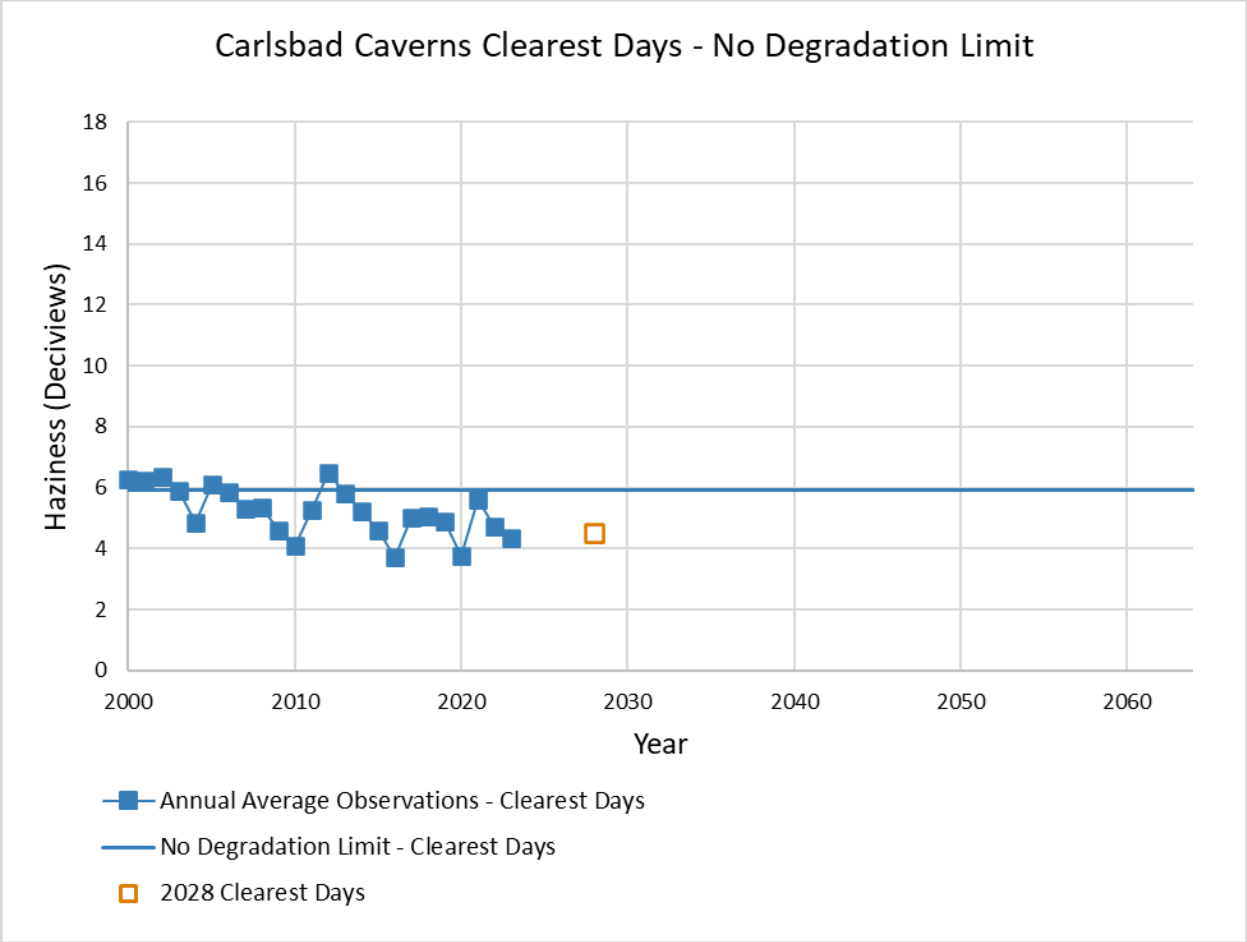


Values for BOAP1:

	Deciviews
No Degradation Limit – Clearest Days	6.3
2028 Clearest Days (Modeled Reasonable Progress Goal)	4.2

9.3.3 Carlsbad Caverns National Park

Figure 9-11: Future Year Clearest Days at Carlsbad Caverns National Park.

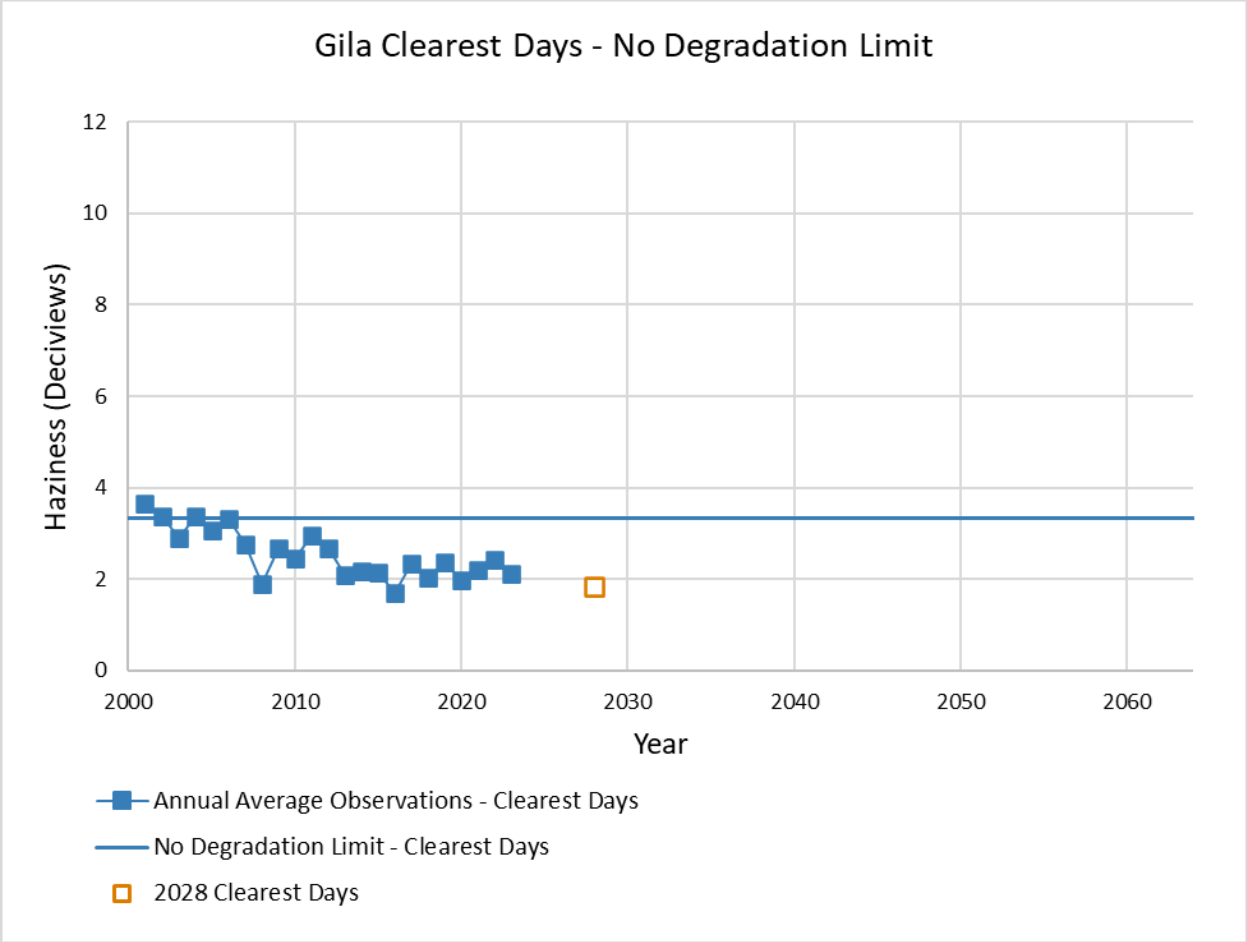


Values for GUMO1:

	Deciviews
No Degradation Limit – Clearest Days	5.9
2028 Clearest Days (Modeled Reasonable Progress Goal)	4.5

9.3.4 Gila Wilderness Area

Figure 9-12: Future Year Clearest Days at Gila Wilderness Area.

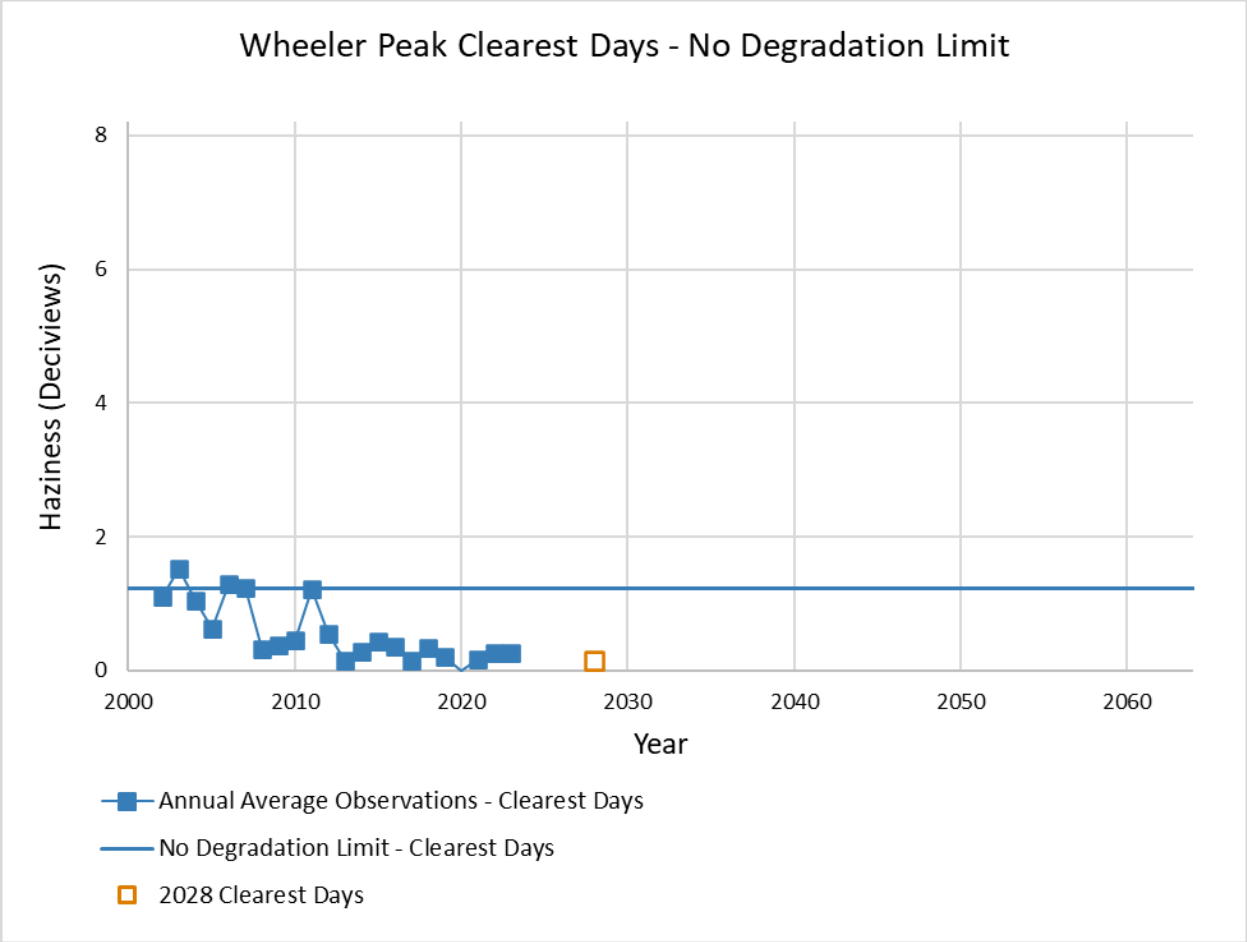


Values for GICL1:

	Deciviews
No Degradation Limit – Clearest Days	3.3
2028 Clearest Days (Modeled Reasonable Progress Goal)	1.8

9.3.5 Pecos Wilderness Area & Wheeler Peak Wilderness Area

Figure 9-13: Future Year Clearest Days at Pecos and Wheeler Peak Wilderness Areas.

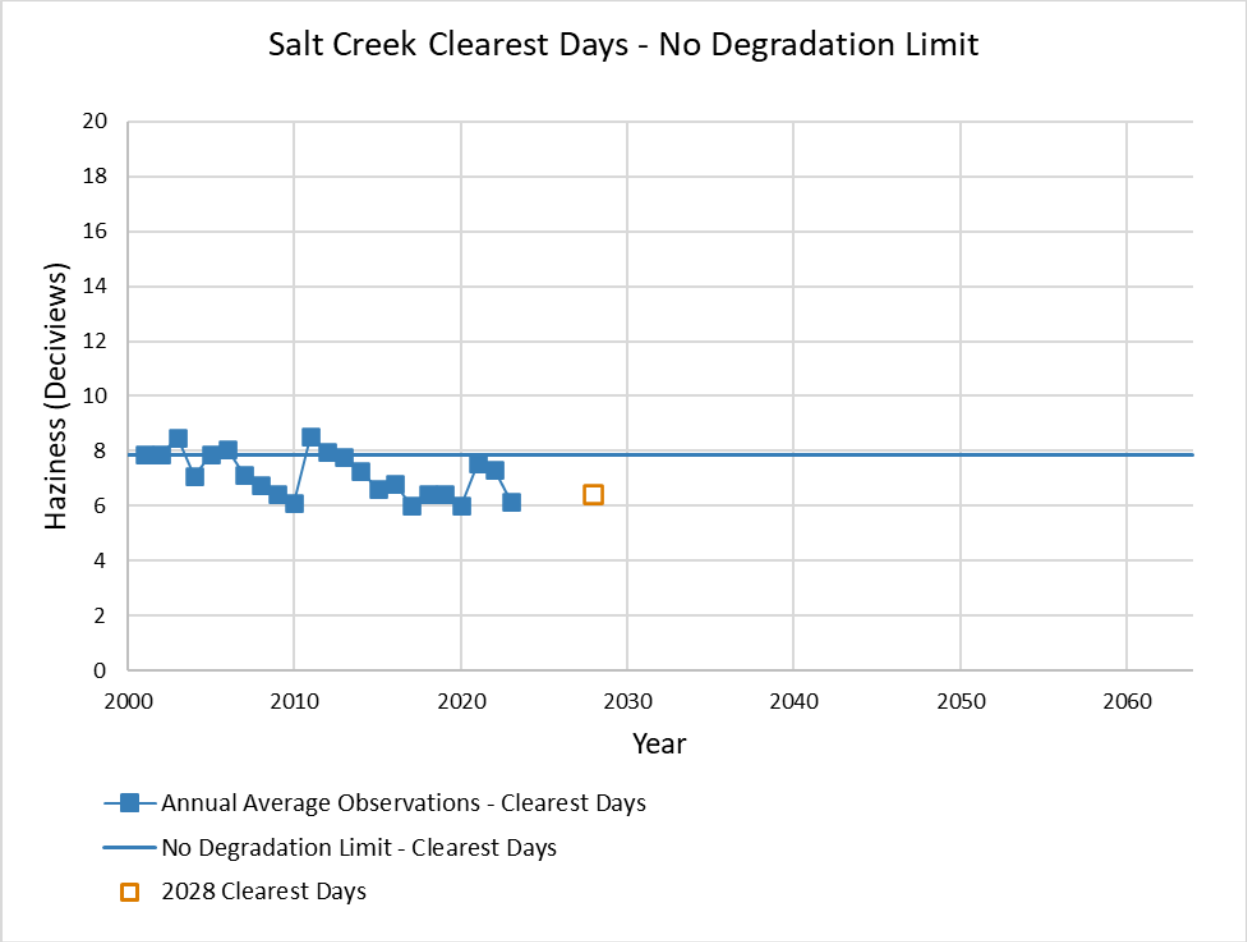


Values for WHPE1:

	Deciviews
No Degradation Limit – Clearest Days	1.2
2028 Clearest Days (Modeled Reasonable Progress Goal)	0.1

9.3.6 Salt Creek Wilderness Area

Figure 9-14: Future Year Clearest Days at Salt Creek Wilderness Area.

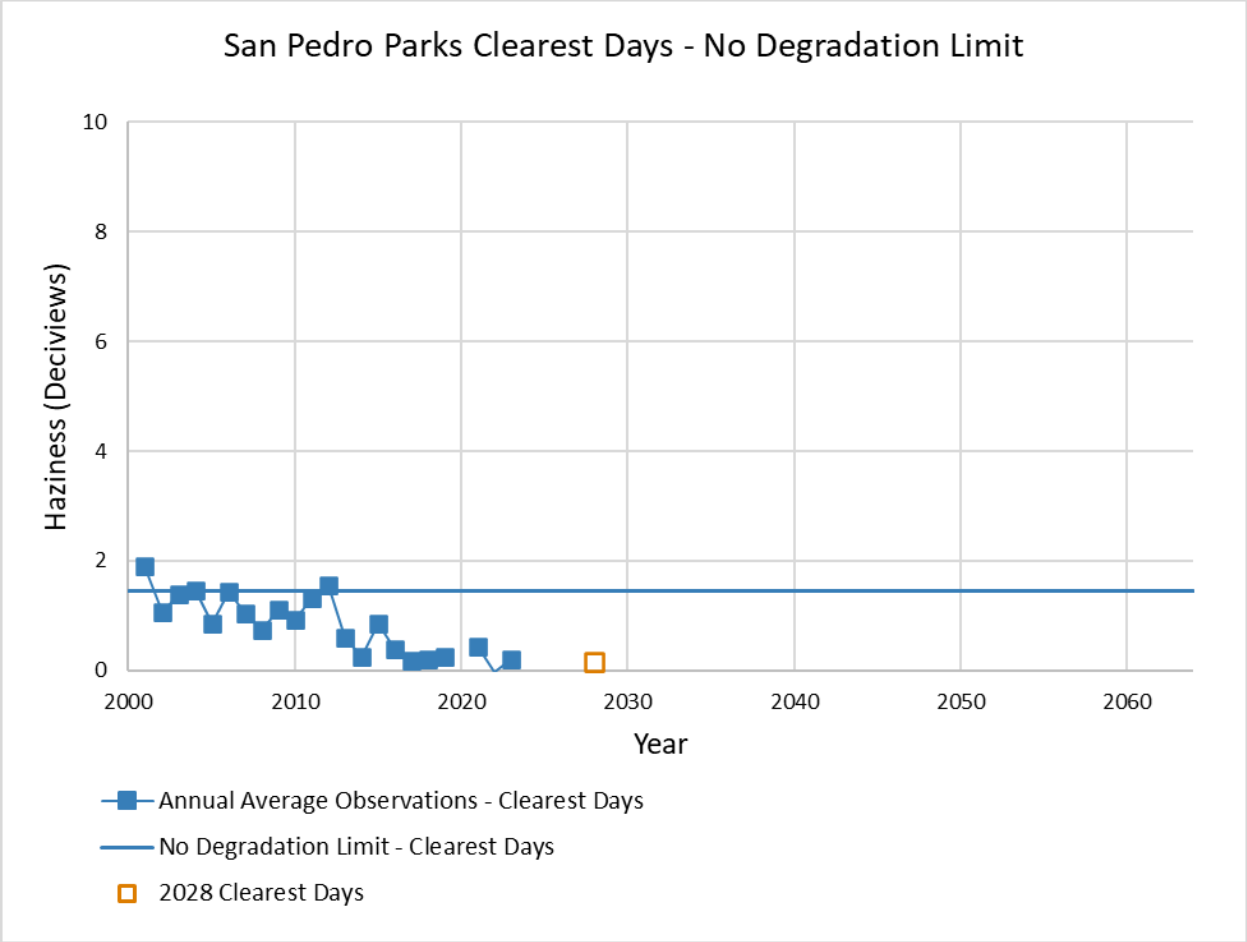


Values for SCAR1:

	Deciviews
No Degradation Limit – Clearest Days	7.8
2028 Clearest Days (Modeled Reasonable Progress Goal)	6.4

9.3.7 San Pedro Parks Wilderness Area

Figure 9-15: Future Year Clearest Days at San Pedro Parks Wilderness Area.

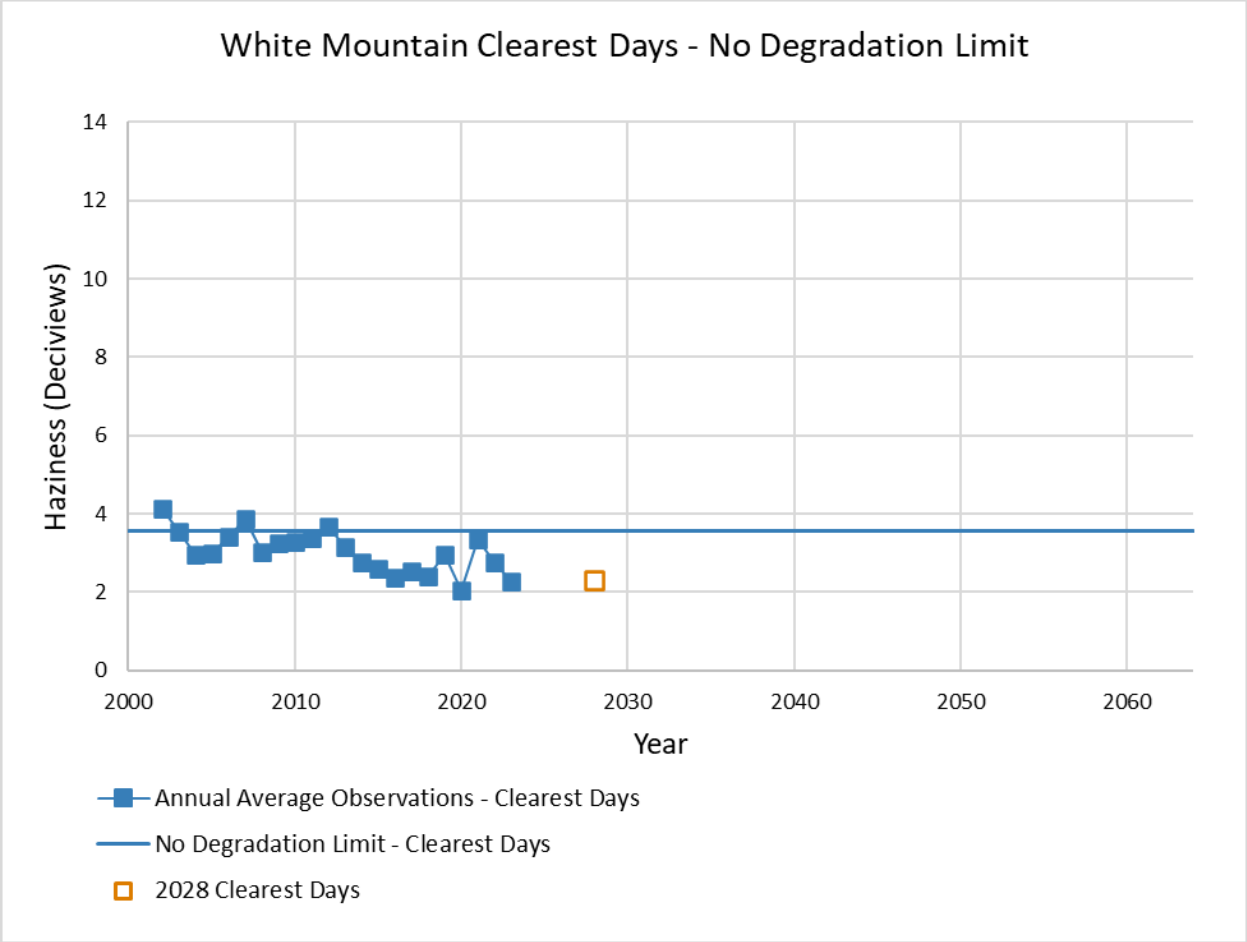


Values For SAPE1:

	Deciviews
No Degradation Limit – Clearest Days	1.5
2028 Clearest Days (Modeled Reasonable Progress Goal)	0.2

9.3.8 White Mountain Wilderness Area

Figure 9-16: Future Year Clearest Days at White Mountain Wilderness Area.



Values for WHIT1:

	Deciviews
No Degradation Limit – Clearest Days	3.6
2028 Clearest Days (Modeled Reasonable Progress Goal)	2.3

Chapter 10: Glidepath Checks for New Mexico Class I Areas and Robust Demonstration

10.1 Regulatory Requirements

The Regional Haze Rule requires the long-term strategy to provide a pathway towards an improvement in visibility for the most impaired days since the baseline period and ensure no degradation in visibility for the clearest days since the baseline period. [175]

The Regional Haze Rule requires that any state containing a Class I Area with a slower rate of improvement than the Uniform Rate of Progress (URP) must provide a robust demonstration [176]. This robust demonstration should include the criteria used to determine which sources were evaluated and how the four-factors required by 40 CFR 51.308(f)(2)(i) were taken into consideration in selecting the measures for inclusion in its long-term strategy. This obligation does not require states to demonstrate their long-term strategy will be sufficient to be on the URP glide path; rather, states should demonstrate that they have taken all reasonable measures to improve visibility in the Class I Area.

10.2 Uniform Rate of Progress Glidepath Check for Most Impaired Days at each Class I Area in New Mexico

Section 9.2 shows the reasonable progress goals as modeled future year most impaired days for each Class I Area in New Mexico. Modeled future year most impaired days are based on the WRAP 2028 'On the Books' modeling scenario (2028OTBa2) [177]. This modeling scenario includes regulations that regulatory agencies already adopted as of September 2020. The future year visibility on the MID at each Class I Area in New Mexico is projected to be below the URP glidepath adjusted for international emissions and wildland prescribed fire, except for Salt Creek Wilderness area (see Section 9.2.6). Salt Creek Wilderness area is projected to be above the URP glidepath in the future year (2028). Section 10.3 is a robust demonstration for Salt Creek Wilderness area.

10.3 Robust Demonstration for Salt Creek Wilderness Area

Salt Creek Wilderness area is projected to be above the uniform rate of progress glidepath in 2028 (according to the 2028 WRAP modeling), and New Mexico contains sources contributing to visibility impairment in the Class I Area. Therefore, a robust demonstration that all reasonable measures have been taken to improve visibility is required.

10.3.1 Monitoring Data at Salt Creek Wilderness Area

The IMPROVE monitoring site for Salt Creek Wilderness Area is discussed In Section 3.3.6 of this Regional Haze SIPr Rd 2 (2019-2028). Monitoring data (Figure 10-1) shows that the primary components of light extinguishing aerosol at SACR1 are ammonium sulfate (31.8% for the 2019-2023 average) and ammonium nitrate (24.7% for the 2019-2023 average) with smaller contributions from Course Mass (18.7% for the 2019-2023 average) and Organic Mass (13.7% for the 2019-2023 average). The rolling five-year average of aerosol light extinction is steadily improving from 2001 to 2023, suggesting that

[175] 40CFR 51.308(f)(3)(i)
[176] 40 CFR 51.308(f)(3)(ii)(A)
[177] https://westar.org/tribal-data-work-group/#tab-id-6

visibility in the Class I Area is improving. Figure 10-2 shows the extrapolation of the improvement trend at SACR1 from the current MID (2001 – 2023) period to the regional haze endpoint adjusted for international emissions and wildland prescribed fire. This extrapolation predicts that if the current trend continues SACR1 will reach the endpoint in 2052, well before the 2064 end of the Regional Haze program.

Figure 10-1 Aerosol Light Extinction for the 20% Most Impaired Days at SACR1.

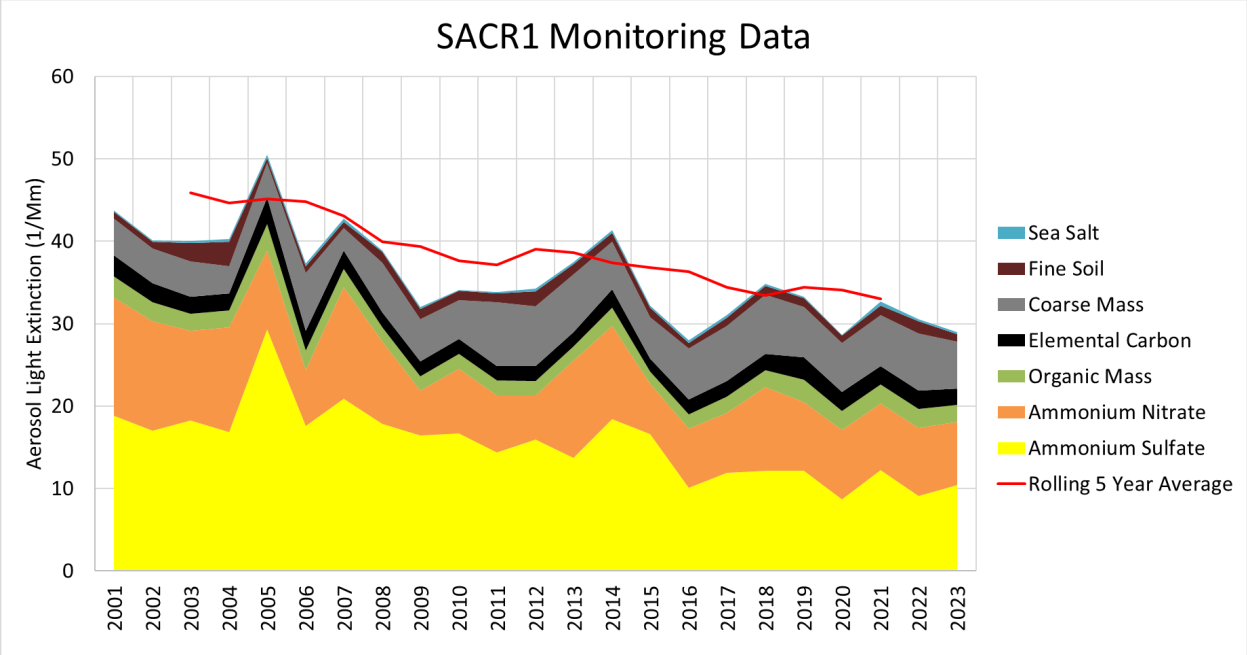
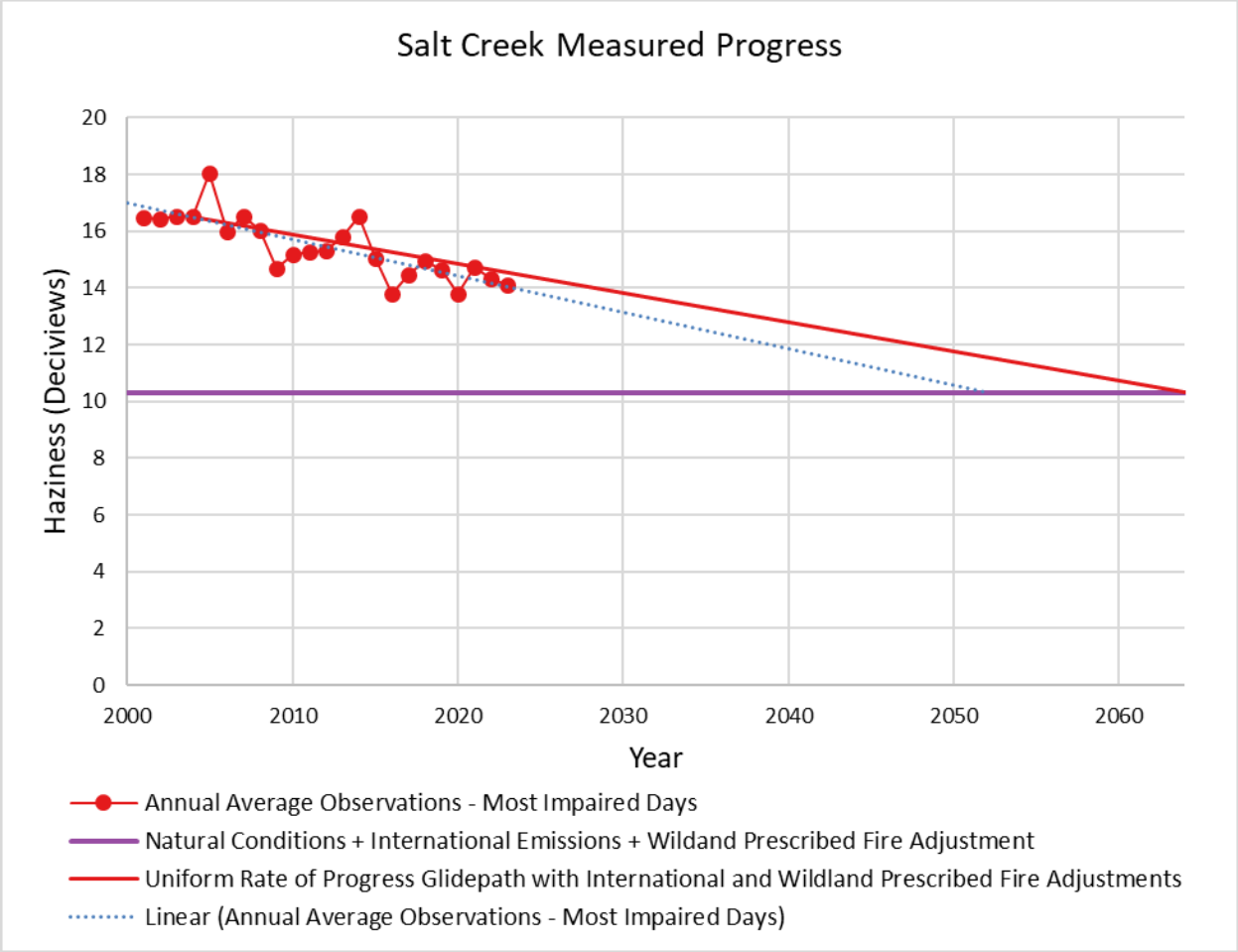


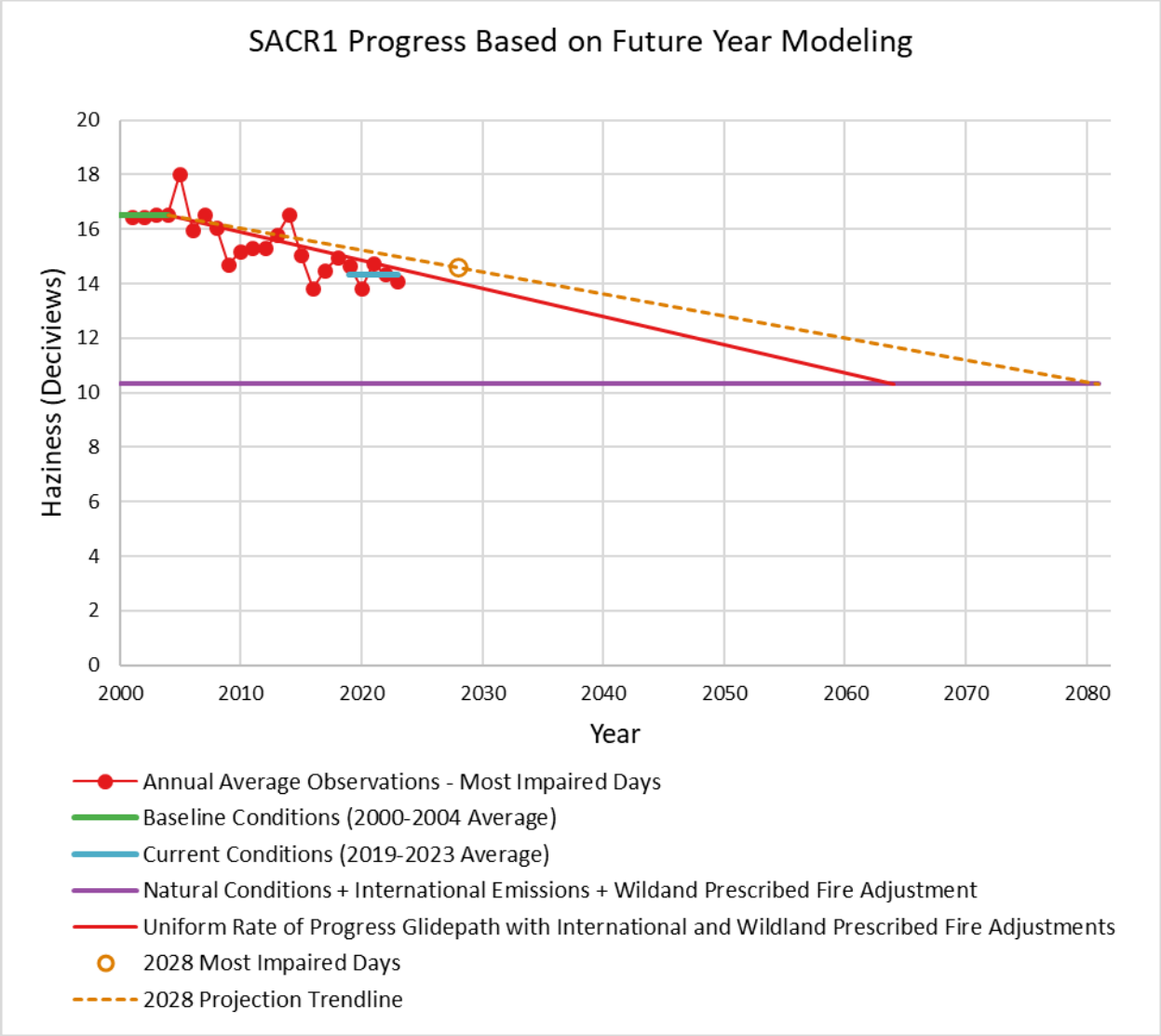
Figure 10-2 Extrapolation of Visibility Improvement at SACR to the Regional Haze Endpoint Based on IMPROVE Monitoring.



10.3.2 Future Year Visibility and Projection to Attainment of the Regional Haze Endpoint at Salt Creek Wilderness Area

The 2017 Regional Haze Rule, 40 CFR 51.308(f)(3)(ii)(A) requires that a state containing a Class I Area which is not projected be below the Uniform Rate of Progress in 2028 must provide to the public an assessment of the number of years it will take to attain natural visibility conditions at the Class I Area at the rate of progress projected for the Long Term Strategy for the Implementation Period. The future year modeled haziness at Salt Creek Wilderness Area is projected to be above the URP Glidepath, adjusted for International Emissions and Wildland Prescribed Fire (Figure 10-3). Extrapolation of this trend from the 2000-2004 baseline period through the future year modeled value to the regional haze endpoint adjusted for international emissions and wildland prescribed fire shows that SACR1 is predicted to reach the endpoint in 2081, 17 years after 2064.

Figure 10-3 Extrapolation of Visibility Improvement the Regional Haze Endpoint Based on Future Year Modeling.



10.3.3 Source Sectors Affecting Visibility at Salt Creek Wilderness Area

Salt Creek Wilderness Area is located in the southeastern area of New Mexico, just outside of the Permian Basin. The Permian Basin is an oil and gas region which has had increasing productivity in recent years. Figure 10-4 shows the location of Salt Creek Wilderness Area (SACR1), the location of the Permian Basin and sub-basins, and the Area of Influence (AOI) predicted for SACR1. The AOI is the percentage air parcels that arrive at SACR1 on the 2014-2018 most impaired days traveling from a location, expressed as residence time. The AOI for SACR1 covers the southeastern part of New Mexico, western Texas, and small areas along the Mexico border and of western Oklahoma.

WRAP $(NH_4)_2SO_4$ source apportionment (Figure 10-5) shows that approximately 36% of anthropogenic $(NH_4)_2SO_4$ at SACR on the 20% most impaired days is from sources in New Mexico, with U.S. states outside of WRAP ('USnonWRAP') contributing approximately 59%, and small contributions from other WRAP states. WRAP NH_4NO_3 source apportionment (Figure 10-6) shows that approximately 63% of

anthropogenic NH_4NO_3 at SACR on the 20% most impaired days is from sources in New Mexico, with U.S. states outside of WRAP contributing approximately 33%, and small contributions from other WRAP states. WRAP source apportionment modeling only included U.S. anthropogenic emissions.

A large percentage of the area of influence (Figure 10-4) overlaps with the geographic extent of the Permian Basin in both New Mexico and Texas, suggesting that oil and gas sources will have an impact on visibility at SACR. The importance of the impact of oil and gas emissions at SACR is shown in the WRAP modeling. WRAP $(NH_4)_2SO_4$ source apportionment (Figure 10-5) shows that approximately 39% of anthropogenic $(NH_4)_2SO_4$ at SACR on the 20% most impaired days is from the oil and gas sector, with an additional 29% originating from Electric Generating Units (EGUs), 23% from Non-EGU point sources, and smaller amounts from the remaining sectors. WRAP NH_4NO_3 source apportionment (Figure 10-6) also shows the largest contribution from the oil and gas sector (76%) with a smaller contribution from mobile sources (12%). Other source sectors contribute small amounts to visibility impairment at SACR.

Figure 10-4 Area of Influence Surrounding Salt Creek Wilderness Area.

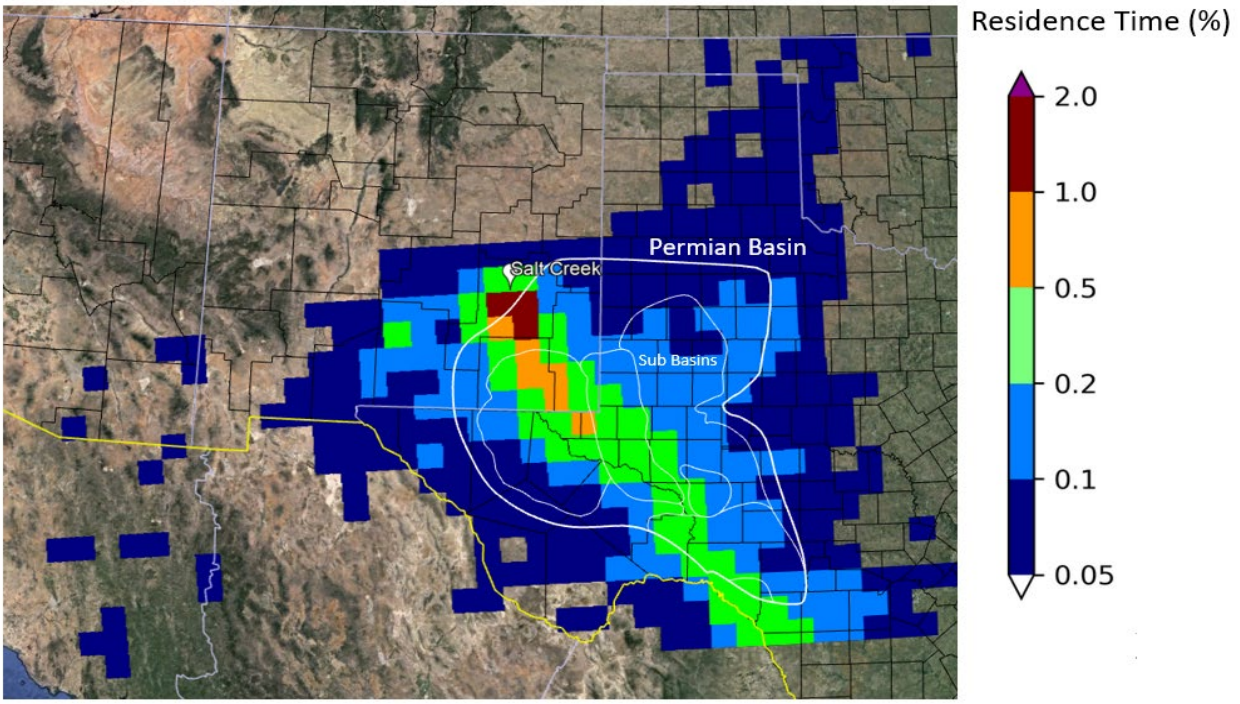


Figure 10-5 WRAP $(NH_4)_2SO_4$ Source Apportionment for Salt Creek on the 20% Most Impaired Days.

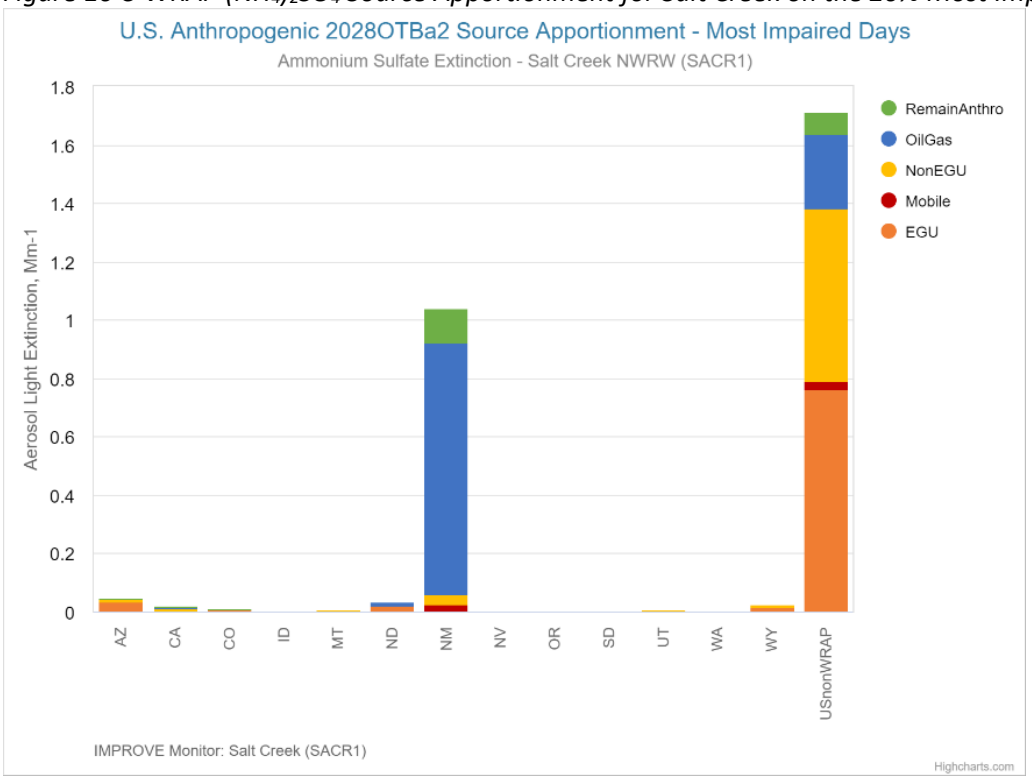
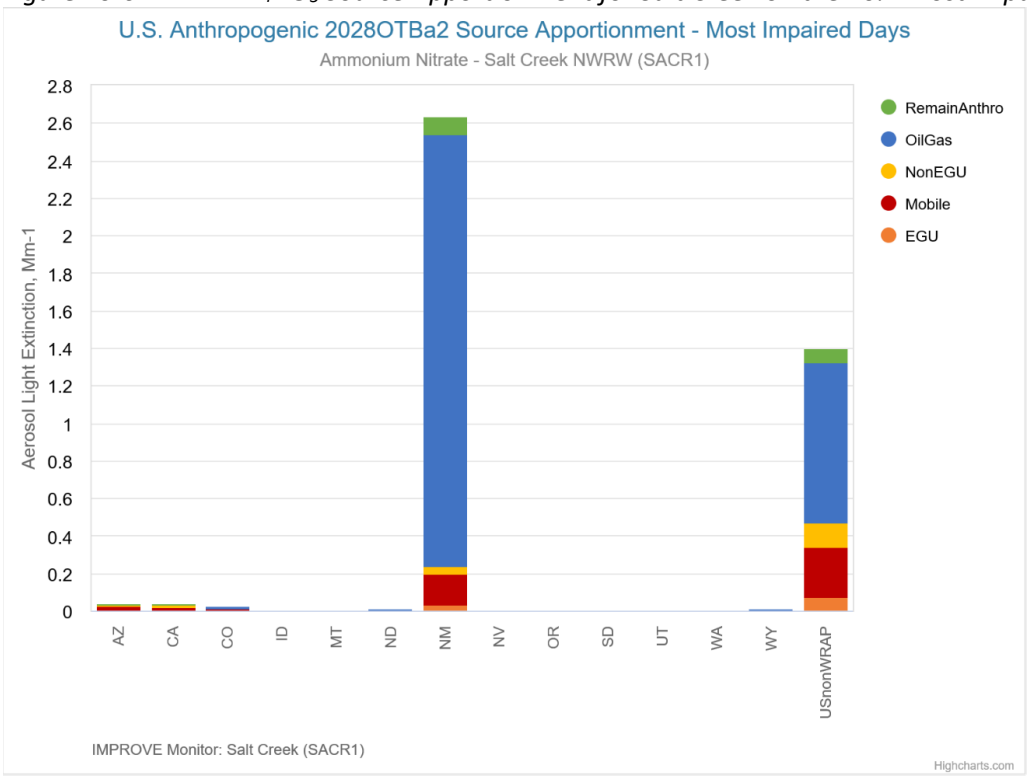


Figure 10-6 WRAP NH_4NO_3 Source Apportionment for Salt Creek on the 20% Most Impaired Days.



10.3.4 Emissions Reductions at Sources Contributing to Visibility Impairment at Salt Creek Wilderness Area

10.3.4.1 Control Measures for Facilities Selected for Four-Factor Analysis in the Permian Basin Area

Sources located in the Permian Basin that were selected by NMED for evaluation (Chapter 6) that underwent a four-factor analysis and control measure determination (Chapter 7) include: Denton Gas Plant, Eunice Gas Plant, Linam Ranch Gas Plant, Pecos River Compressor Station, Washington Ranch Storage Facility, South Carlsbad Compressor Station, Jal #3 Gas Plant, Bitter Lake Compressor Station, Roswell Compressor Station No. 9, Indian Basin Gas Plant, Eunice Gas Processing Plant, Monument Gas Plant, Saunders Gas Plant, and Cunningham Station Power Plant. From these facilities, a combined total of 61 units (or systems) have proposed limitations as part of reasonable progress in NMED's long-term strategy for the second planning period.

10.3.4.2 Emissions Reductions Due to Compliance and Enforcement Settlements in the Second Planning Period

In addition to the "measures necessary to make reasonable progress," discussed in Section 10.3.4.1, NMED has also issued several compliance orders above and beyond what was part of the source selection process. While these additional facilities/sources were not considered to be necessary for reasonable progress, these additional compliance orders for oil and gas facilities, located in the Permian Basin, have a direct impact on visibility-impairing pollution. These are mentioned here as additional weight of evidence that NMED is prioritizing the mitigation of anthropogenic sources of visibility impairing pollution in the area of influence of Salt Creek Wilderness Area.

April 29, 2024 – Ameredev Settlement – This settlement agreement, due to the cessation of excess emissions and a yet-to-be-determined mitigation project, will result in reductions of NO_X and other pollutants that cannot be quantified at this time.

March 27, 2023 – Matador Production Company – This Consent Decree, due to a program of engine replacement, is estimated to result in an additional reduction of 77 tons of NO_X over the next three years.

10.3.5 Summary and Visibility Outlook at Salt Creek Wilderness Area

NMED reviewed the IMPROVE monitoring trends through 2023 at Salt Creek Wilderness Area and observed that monitored IMPROVE visibility (in deciviews) is trending closer to aligning with the uniform rate of progress for most impaired days than the 2028 modeling indicates. The 2028 reasonable progress goals (as estimated in deciviews) are based on the 2028 OTBa2 WRAP modeling scenario, that most likely does not fully take into consideration most of the additional control measures being mandated in NMED's SIP Revision - Long-term strategy. Even so, in Section 10.3.2, NMED has calculated the number of years it would potentially take to attain the natural visibility conditions, [178] if visibility improvement were to continue at the rate of progress, based on the WRAP 2028 OTBa2 scenario. [179] EPA's guidance reads that "a state could provide within its SIP submission a narrative explanation of how the state has already conducted the source selection and control measures analyses in such a manner

[178] This included NMED's adjustment of the glidepath for international anthropogenic emissions and prescribed fire.

[179] 40 CFR 51.308(f)(3)(ii)

that addresses the [robust demonstration requirements]." [180] This is the case with the NMED SIP Revision as demonstrated in Section 10.3.4.

10.4 No Degradation Check for New Mexico Class I Areas

Section 9.3 shows the reasonable progress goals as modeled future year clearest days for each Class I Area in New Mexico. The future year visibility on the clearest days is projected to be below the no degradation limit at all Class I Areas in New Mexico. This demonstrates that the long-term strategy provides for no degradation in visibility at all New Mexico Class I Areas for the clearest days since the baseline period. [181]

[180] EPA Regional Haze SIP Guidance, pp. 50 to 51.
[181] 40CFR 51.308(f)(3)(i)

Chapter 11: Coordination and Discussions with Other Parties

The U.S. Environmental Protection Agency's (EPA) August 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period includes a Step 8a – "Additional Requirements for Regional Haze SIPs - Coordination and Discussions with Other Parties." [182]

EPA's guidance provides a roadmap for how states can satisfy some of the Regional Haze Rule requirements pertaining to coordination, specifically, as it pertains to:

- Consultation with other states;
- Consultations, notification and information sharing between New Mexico and Federal Land Managers (FLMs);
- Discussions with the Environmental Protection Agency (EPA); and
- Discussions with Tribes.

Because the pollutants that lead to regional haze can originate from sources located across broad geographic areas, EPA has encouraged the states and Tribes across the U.S. to address visibility impairment from a regional perspective, through Regional Planning Organizations (RPOs). New Mexico belongs to the Western Regional Air Partnership (see Figure 11-1).

Figure 11-1: Regional Planning Organizations.



As described in Chapter 1, these organizations evaluate technical information to better understand how their states and Tribes impact national parks and wilderness areas (Class I Areas) across the country, pursue the development of regional strategies to reduce emissions of pollutants that cause visibility

[182] EPA Regional Haze SIP Guidance, pp. 52 to 56.

impairment, and help states meet the consultation requirements of the Regional Haze Rule. Because the content of SIPs may affect air quality in and around Tribal land, EPA has indicated it recognizes the value in EPA, states, and multi-state organizations maintaining a dialogue with Tribes through all stages of developing regional haze SIPs.[182]

In 2018, WRAP's Regional Haze Planning Work Group formed specific subcommittees for the second planning period to develop Regional Haze data sets and recommendations on how to use the data.

11.1 Coordination with Local Jurisdictions and Other States

Because of the scope and design of the Regional Haze Rule, NMED prepared this Regional Haze SIPr Rd 2 (2019-2028) in close cooperation with the City of Albuquerque Environmental Health Department (EHD). Under state and local law, EHD prepares SIPs applicable to Albuquerque and Bernalillo County, proposing them for consideration by the Albuquerque - Bernalillo County Air Quality Control Board. [183] Separately, NMED prepares SIPs for the rest of the state and proposes them for consideration by the New Mexico Environmental Improvement Board (EIB). [184] Upon adoption by the EIB, NMED submits SIPs to EPA for final approval.

Coordination with other Western Region states has been mainly through WRAP. In addition to this broader-level coordination, NMED has also met informally with states in the Four-Corners region, including Arizona Department of Environmental Quality (Arizona DEQ), Utah Department of Environmental Quality (Utah DEQ), and Colorado Department of Public Health and Environment (CDPHE) as a group through the Four Corners Air Quality Group. NMED has also met one-on-one with the Texas Commission on Environmental Quality (TCEQ), Arizona DEQ, Utah DEQ, and CDPHE to help check in and coordinate the development of our respective Regional Haze draft SIPs.

In 2021, TCEQ reached out to NMED for a series of consultations, which primarily focused on sharing information from TCEQ on their modeling and draft SIP long-term strategy for reasonable progress. NMED provided some feedback, including suggestions that Texas consider further evaluating some of the sources impacting the Permian Basin area. At that time, WRAP had yet to complete the photochemical modeling that was part of the WRAP work plan, and NMED had yet to decide on its draft long-term strategy. NMED did share its source selection with TCEQ during the 2021 coordination. NMED's communication to TCEQ during this phase, prior to NMED's first draft SIPr Rd 2, is provided for reference in Appendix E.

Contiguous states, by their geographic proximity, have some potential interstate emissions impacts; however, for the purposes of second period Regional Haze planning, NMED did not make any specific requests for other states to require control measures at specific facilities. Likewise, no neighboring state or other state requested that NMED require controls at sources regulated by NMED. Communications and interactions with other states related to Regional Haze planning were primarily informal and consisted of information sharing. The suite of tools WRAP developed to help states address potential impacts of interstate emissions was mostly qualitative in nature. NMED used a qualitative tool, Q/d, for source screening, as discussed in Chapter 6. Other qualitative tools that later became available on source apportionment and estimating areas of influence are weight of evidence supporting NMED's long-term strategy and robust demonstration.

[183] NMSA 1978 §§ 74-2-5 and 74-2-5.1; ROA 1994 §§ 9-5-4 and 9-5-1-5; Bernalillo County Code §§ 30-33 and 30-34.
[184] NMSA 1978 §§ 74-2-5 and 74-2-5.1.

As part of the external outreach process, NMED shared the FLM review draft SIP revision - version 2024-05-20, with all five contiguous states (Texas, Arizona, Utah, Colorado, and Oklahoma), as well as the City of Albuquerque on June 20, 2024. NMED requested feedback by July 19, 2024. Only Arizona DEQ and TCEQ provided responses to NMED. The Arizona DEQ response on July 16, 2024, stated that they do not have comments or requests for NMED. TCEQ submitted a comment letter. Both responses are included in Appendix E. Neither Arizona DEQ, TCEQ, nor any other state has asked NMED for any additional sources to be analyzed or any specific control measures to be implemented at any source in New Mexico in order to meet their reasonable progress goals.

11.2 Consultation, Notification and Information Sharing between New Mexico and Federal Land Managers

NMED began coordination on the second planning period with its federal land manager (FLM) partners early in 2019, working together to determine which sources would be selected to undergo further evaluation for the long-term strategy. NMED continued to meet informally with FLMs from 2019 to the present to discuss various aspects of technical planning. NMED was also highly involved in and regularly participated in the in-depth Western Regional Air Partnership regional planning process which included FLMs, EPA, states, local agencies, and Tribes. Informal check-ins with the U.S. National Park Service and U.S. Forest Service occurred more recently, in the fall of 2023. Upon completion, a FLM review draft Regional Haze SIPr Rd 2 (2019-2028) was distributed to FLMs on May 20, 2024 to begin the formal FLM review period.

NMED values coordination with FLM and other partners in the Regional Haze Program. As part of the coordination and consultation with FLMs for the second planning period, NMED has followed the requirements for FLM coordination mandated by the Clean Air Act and Regional Haze Rule.

- Following a formal FLM review period, which began on May 20, 2024, and ended July 26, 2024, all comments received were considered before a revised draft Regional Haze SIPr Rd 2 (2019-2028) was developed in advance of NMED's public hearing process [185].
- An informational overview and summary webinar on the plan was held exclusively for FLMs on June 6, 2024, to provide a platform for initial questions and answers. All partner FLMs were in attendance for this event. A second meeting was scheduled by the National Park Service (NPS) on July 11, 2024, where they provided feedback on the FLM review draft prior to submitting formal written comments. Representatives from the U.S. Fish and Wildlife Service, U.S. Forest Service, and EPA were also in attendance for this meeting and were able to provide feedback.
- NMED followed the additional requirement from 42 USC § 7491(d) that NMED shall include a summary of the conclusions and recommendations of the federal land managers in the public hearing notice on the proposed Regional Haze SIPr Rd 2 (2019-2028). [186]
- Appendices E and F provide documentation of key communications between NMED and FLMs.
- Before submitting an EIB-adopted plan to EPA Region 6, NMED provided a description on how comments provided by the FLMs were addressed in the Regional Haze SIPr Rd 2 (2019-2028). [187]
- NMED values coordination between FLMs and other partners in the Regional Haze Program and plans to continue coordinating with FLMs on maintaining and improving visibility at Class I Areas. [188]

[185] 40 CFR § 51.308(i)(2).
[186] 42 USC § 7491(d).
[187] 40 CFR § 51.308(i)(3).
[188] 40 CFR § 51.308(i)(4).

11.3 Discussions with Environmental Protection Agency

NMED began discussions with its EPA regional office (Region 6) about New Mexico's plans and progress in developing a Regional Haze SIPr Rd 2 (2019-2028) early and discussions continued throughout the SIP development process. In these discussions, EPA has provided feedback to the state on how the provisions of the Regional Haze Rule and the recommendations in EPA guidance can be applied in the context of New Mexico's SIP. EPA has shared EPA technical products, as appropriate and relevant. NMED has encouraged collaboration between EPA Region 6 and New Mexico's regional planning organization (WRAP).

As part of the external review process, NMED shared the FLM review draft with EPA Region 6 on May 23, 2024. NMED provided through July 26, 2024, for EPA to provide feedback. NMED granted EPA an additional extension to July 30, 2024, at which time EPA submitted comments to NMED. NMED also provided a public review draft SIP revision and draft new Regional Haze rule to EPA Region 6 on August 26, 2024. EPA provided NMED additional comments related to the draft new rule, NMAC 20.2.68 – Regional Haze Requirements, on September 9, 2024. EPA's comments are included in Appendix E.

11.4 Coordination with Tribes, Nations, and Pueblos

While there are no specific state-Tribal consultation requirements set by federal legislation, NMED recognizes the State of New Mexico is home to many Tribes, Nations, and Pueblos and values coordinating with Tribes on projects that may impact air quality in and around Tribal land.

NMED conducted additional outreach to Tribal leaders in New Mexico, notifying them of the availability of the draft SIP revision. A letter was sent via email to the following Tribes, Nations, and Pueblos on June 10, 2024, which provided a link to the draft Regional Haze SIPr Rd 2 (2019-2028) and notifying them of upcoming engagement opportunities. These meetings were conducted online via Webex on June 18 and June 20, 2024, which saw several members of Tribal leadership and environmental department representatives in attendance. Copies of the letters transmitted to Tribal leaders and environmental contacts are provided in Appendix E. Further communication and engagement opportunities were offered both in the letter and during the webinar.

- Pueblo of Acoma
- Pueblo of Cochiti
- Pueblo of Isleta
- Pueblo of Jemez
- Pueblo of Laguna
- Pueblo of Nambe
- Pueblo of Ohkay Owingeh
- Pueblo of Picuris
- Pueblo of Pojoaque
- Pueblo of San Felipe
- Pueblo of San Ildefonso
- Pueblo of Sandia
- Pueblo of Santa Ana
- Pueblo of Santa Clara
- Pueblo of Santo Domingo
- Pueblo of Taos
- Pueblo of Tesuque
- Pueblo of Zia
- Pueblo of Zuni
- Pueblo of Ysleta Del Sur
- Navajo Nation
- Navajo Nation Council
- Jicarilla Apache Nation
- Mescalero Apache Tribe
- Fort Sill Apache Tribe
- Ute Mountain Ute Tribe

11.5 Industry Specific Engagement on Sources Selected for Four-Factor Analysis

NMED engaged directly with industry as part of the outreach program. Updates on the Regional Haze SIPr Rd 2 (2019-2028) progress were provided as milestones were met, or as otherwise necessary. Outreach began with source selection notifications in 2019, [189] and communication with industry has been ongoing since that date. Whenever key updates or milestones were reached, industry members were notified. In May 2023, NMED contacted all affected companies and offered to meet with them to discuss any new updates or plans regarding selected sources to help NMED finalize its four-factor analyses. Copies of these communications to affected companies are included in Appendix E. Meetings were held between May 2023 to November 2023 with all companies that requested to meet including: DCP Operating Company, El Paso Natural Gas Company, Enterprise Field Services, ET Gathering & Processing, Transwestern Pipeline Company, Harvest Four Corners, Hilcorp Energy Company, IACX Roswell, Targa Midstream Services, and Xcel Energy. NMED shared draft final cost evaluations with all affected companies in early December 2023, and accepted feedback from them through January 15, 2024. Several facilities requested meetings with the department early in 2024, which allowed additional opportunities to receive comments and provide more information regarding the content of these documents. NMED also shared a public review draft Regional Haze SIPr Rd 2 on August 26, 2024, and requested feedback and comment. Advance notice was provided to affected industry of public review draft availability, as coordination with industry is an important element of the SIPr development process. NMED received comments during the August 26,2024 – September 20, 2024 public review period from DCP Operating Company, El Paso Natural Gas Company (EPNG), Enterprise Field Services, and Public Services Company of New Mexico. Clarifying questions were also asked by Transwestern Pipeline and answered by NMED. After the conclusion of the public review draft comment period, EPNG requested an additional meeting with NMED to discuss their comments further and provide recommendations concerning potentially affected EPNG facilities/units. Subsequently, NMED met with EPNG on October 22, 2024, to listen to their suggestions and recommendations. Comments received from industry during the public review period are included in Appendix E.

11.6 General Outreach, Education, and Stakeholder Engagement

In partnership with City of Albuquerque-EHD, NMED conducted introductory Regional Haze planning public webinars in 2019-2020. Additional stakeholder webinars were hosted by NMED in 2023. NMED also has maintained a Regional Haze planning website at https://www.env.nm.gov/air-quality/reg-haze/ and provided announcements regarding regional haze planning through its listservs.

NMED distributed a public review draft SIPr (2019-2028) and a draft new companion rule, 20.2.68 NMAC – Regional Haze Requirements, in August 2024, for review and comment by members of the public, industry and other stakeholders. During this phase, two public information webinars were hosted by NMED to provide an overview on the public review drafts and receive feedback and questions from stakeholders. NMED received comments on the public review drafts from Sierra Club, Wild Earth Guardians, and Western Environmental Law Center. These comments are included in Appendix E.

[189] See Appendix E

11.7 Overarching Responses to Comments Received.

At the conclusion of the FLM consultation period, NMED received substantive comments from the U.S. National Park Service (NPS) and EPA Region 6. See Appendix E for EPA comments, and Appendix F for the formal FLM comments. The NPS comments were largely focused on concerns regarding NMED's evaluation of selective catalytic reduction (SCR) for natural gas-fired combustion turbines. NMED carefully considered the comments and revised its SCR analyses in response, resulting in some changes to its control measures determinations and long-term strategy. By and large, other FLM comments commended NMED on engagement, source selection, and the long-term strategy. A summary of the FLMs' conclusions and recommendations follows:

- U.S. National Park Service – "We greatly appreciate NMED's FLM early and frequent consultation engagement process. We also commend your approach for source selection, agree with not using visibility benefits in potential control measure determinations, and generally support criteria used in Reasonable Progress determinations. We are providing comments on NMED's approach to selective catalytic reduction (SCR) costs and/or feasibility review along with recommendations for specific facility determinations. Overall, the NPS finds your plan to be clear, concise, and well-organized with significant reductions proposed at 13 facilities in New Mexico." (7/26/24)
- U.S. Forest Service – "We are satisfied with the document as provided and offer no suggestions for change beyond the informal suggestions to clarify language that were shared via email on July 19th, 2024. We appreciate the opportunity to work closely with the New Mexico Environment Department. The Forest Service compliments you on your hard work and dedication to significant improvement in our nation's air quality values and visibility." (7/19/24)[190]
- U.S. Fish and Wildlife Service – indicated the SIP was one of, if not the best, of all that had been reviewed thus far. (7/11/24)

EPA Region 6 also commented on the regulatory mechanism for making the emissions limitations and other measures in the draft SIP federally enforceable. NMED determined that promulgating a new rule containing the emissions limitations, compliance deadlines, and other measures necessary for reasonable progress was the best option. NMED drafted a new rule, 20.2.68 NMAC – Regional Haze Requirements, [191] as a companion to the SIP. Other recommendations by EPA on strengthening parts of the SIP were determined to require considerable additional analysis which would result in further delay and would not have a substantive effect on the proposed long-term strategy or robust demonstration. NMED's source selection, as required by the Regional Haze rule, was made in 2019 and was discussed frequently with WRAP and other stakeholders. FLMs were consulted with at that time and agreed on the source selection. This step determined the analysis required for the subsequent steps, including the four-factor analysis and the control measure determinations developed for the long-term strategy. FLMs have applauded NMED's source selection and EPA has informally commented that our source selection was adequate. The full content of EPA's recommendations to NMED are available in Appendix E.

NMED received other informal comment letters from TCEQ and the Ute Mountain Ute Tribe, included in Appendix E. The comments from TCEQ provided supplemental information on emissions inventories in Texas. NMED is part of the Western Regional Air Partnership (WRAP) and relied on emissions inventories

[190] NMED revised the draft SIP to incorporate all the USFS Informal comments related to U.S. National Forest descriptions and the IMPROVE monitoring network.

[191] See Appendix G

and modelling provided by the WRAP to prepare this SIP revision. Information provided from TCEQ in this comment letter, 7/16/24, came after the WRAP completed its work plan for the second planning period and finalized the WRAP Technical Support System (TSS). See Appendix A and B for more information on the WRAP TSS. NMED also appreciates the engagement and comments from the Ute Mountain Ute Tribe. The comments were primarily on the embedded progress report and do not substantively affect NMED's process or determinations made for this second planning period SIP revision. NMED did not make changes to the public review draft SIP in response to either of these sets of comments.

During the general stakeholder outreach process, the National Parks Conservation Association and other environmental groups also engaged with NMED and provided comments during the development of this Regional Haze SIPr Rd 2 (2019-2028). NMED appreciates the engagement and feedback from NPCA, other environmental groups, and all the other stakeholders that have participated in the stakeholder engagement process.

Nine organizations, including five affected companies, three environmental advocacy groups, a federal land manager, and EPA submitted comments on the public review drafts of New Mexico's Regional Haze plan and new companion rule. The review period spanned August 26 – September 20, 2024. NMED held two stakeholder engagement webinars (9/9) and (9/10) during the review period. All comments submitted during the public review period are included in Appendix E.

Additional comments were submitted to NMED as part of the engagement process after the petition, involving all parties that submitted entries of appearance in the hearing. These comments are also included in Appendix E.

NMED weighed the evidence provided in comments and then made revisions to the proposed plan and rule in cases where the evidence supported those revisions. Substantive revisions included:

- NMED revised the assumed NO_X removal efficiency of SCR for certain units based on feedback from industry.
- NMED revised the methodology used for adjusting estimated costs from previous year dollars to 2024 dollars based primarily on feedback from industry.
- NMED updated the bank prime interest rate from 8.5% to 7.5%, the current overnight lending rate as of December 2024, based on feedback from environmental groups and industry.

In addition to the changes described above, NMED has made a number of non-substantive revisions to NMED's proposed regional haze SIP revision. These include correcting typographical errors, providing further explanation in various places at the request of EPA, and providing additional time for one unit to come into compliance with a new emission limit that reflects a control the owner is currently installing for compliance with 20.2.50 NMAC.

Chapter 12: Monitoring Strategy and Other Elements

12.1 Regulatory Requirements

The U.S. Environmental Protection Agency's (EPA) August 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period includes a final section for "Additional requirements for regional haze SIPs." [192] This section is a "catch-all" for Regional Haze Rule requirements that have not already been addressed elsewhere in EPA's Guidance. That section lists three requirements: a) Consultation and discussions with other parties, which is covered in Chapter 11 of this Regional Haze SIPr Rd 2 (2019 – 2028); b) Progress report elements, which is covered in Chapter 5; and c) Monitoring strategy and other elements, which is covered in this chapter. The specific regulatory requirements that this chapter addresses are as follows:

1) An assessment of the current monitoring strategy necessary for measuring, characterizing, and reporting of regional haze visibility impairment that is representative of all Class I Areas within New Mexico; for determining the contribution of emissions from within New Mexico to regional haze visibility impairment at Class I Areas in other States; for reporting all visibility monitoring data to the EPA Administrator at least annually; and for any other measure–including reporting and recordkeeping–necessary to assess and report on visibility. [193]
2) The provisions for a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any Class I Area; and a commitment to update the inventory periodically. [194]

12.2 Assessment of Current Monitoring Strategy

The Regional Haze Rule requires that "The State must submit with the implementation plan a monitoring strategy for measuring, characterizing, and reporting of regional haze visibility impairment that is representative of all mandatory Class I Federal areas within the State. Compliance with this requirement may be met through participation in the Interagency Monitoring of Protected Visual Environments (IMPROVE) network." [195]

The primary monitoring network for regional haze, both nationwide and in New Mexico, is the IMPROVE network. IMPROVE network operations are governed by a Steering Committee that guides the management of the monitoring network and the collection of data for use in complying with the Regional Haze Rule. The IMPROVE Steering Committee consists of representatives from 10 voting member organizations. These organizations include:

- U.S. Forest Service (USFS);
- National Park Service (NPS);
- U.S. Fish and Wildlife Service (FWS);
- Bureau of Land Management (BLM);
- Environmental Protection Agency (EPA);
- National Oceanic & Atmospheric Administration (NOAA);
- National Association of Clean Air Agencies (NACAA);
- Northeast States for Coordinated Air Use Management (NESCAUM);

[192] EPA Regional Haze SIP Guidance, pp. 52 to 56.
[193] 40 CFR § 51.308(f)(6)(ii), (iv) and (vi).
[194] 40 CFR § 51.308(f)(6)(v).
[195] 40 CFR § 51.308(f)(6).

- Western States Air Resources Council (WESTAR); and
- Mid-Atlantic Regional Air Management Association (MARAMA).

Members of the Steering Committee are appointed by their organizations and serve an indefinite term determined by their organization. The Steering Committee also has three non-voting associate members:

- Arizona Department of Environmental Quality;
- Environment and Climate Change Canada; and
- Republic of Korea Ministry of Environment.

WESTAR is the agency that represents New Mexico's interests on the IMPROVE Steering Committee along with those of its other members.[196] The existing IMPROVE network was deemed adequate to assess whether our RPGs are being met so no additional monitoring sites are needed at this time. The Steering Committee allocates monitoring resources, which come from several agencies. The IMPROVE program arranges for the operation of monitors, the analysis of samples, and the validation and posting of the data on the internet. EPA takes associated program support funds for IMPROVE monitor sites from the annual State and Tribal Assistance Grant budgets, then allocates the remaining grant amount to states. EPA doesn't withhold different amounts from each state for the 110 IMPROVE sites. For FY 2023 and FY 2024, about $4 million of $PM_{2.5}$ monitoring funds was proposed to support visibility monitoring at 110 IMPROVE sites and two sites collocated with Clean Air Status and Trends Network monitoring sites.[197]

Given that IMPROVE monitoring data from 2000 – 2004 serves as the baseline for the Regional Haze Program, the future regional haze monitoring strategy must necessarily be based on – or directly comparable to – the current IMPROVE monitoring program. IMPROVE measurements provide the only long-term record available for tracking visibility improvement or degradation and, therefore, New Mexico intends to continue relying on the IMPROVE monitoring program for complying with the monitoring requirements in the Regional Haze Rule. The IMPROVE monitoring program's practice of providing data directly to EPA satisfies the requirements in sections 51.308(f)(6)(iv) and (vi) of the Regional Haze Rule.[198]

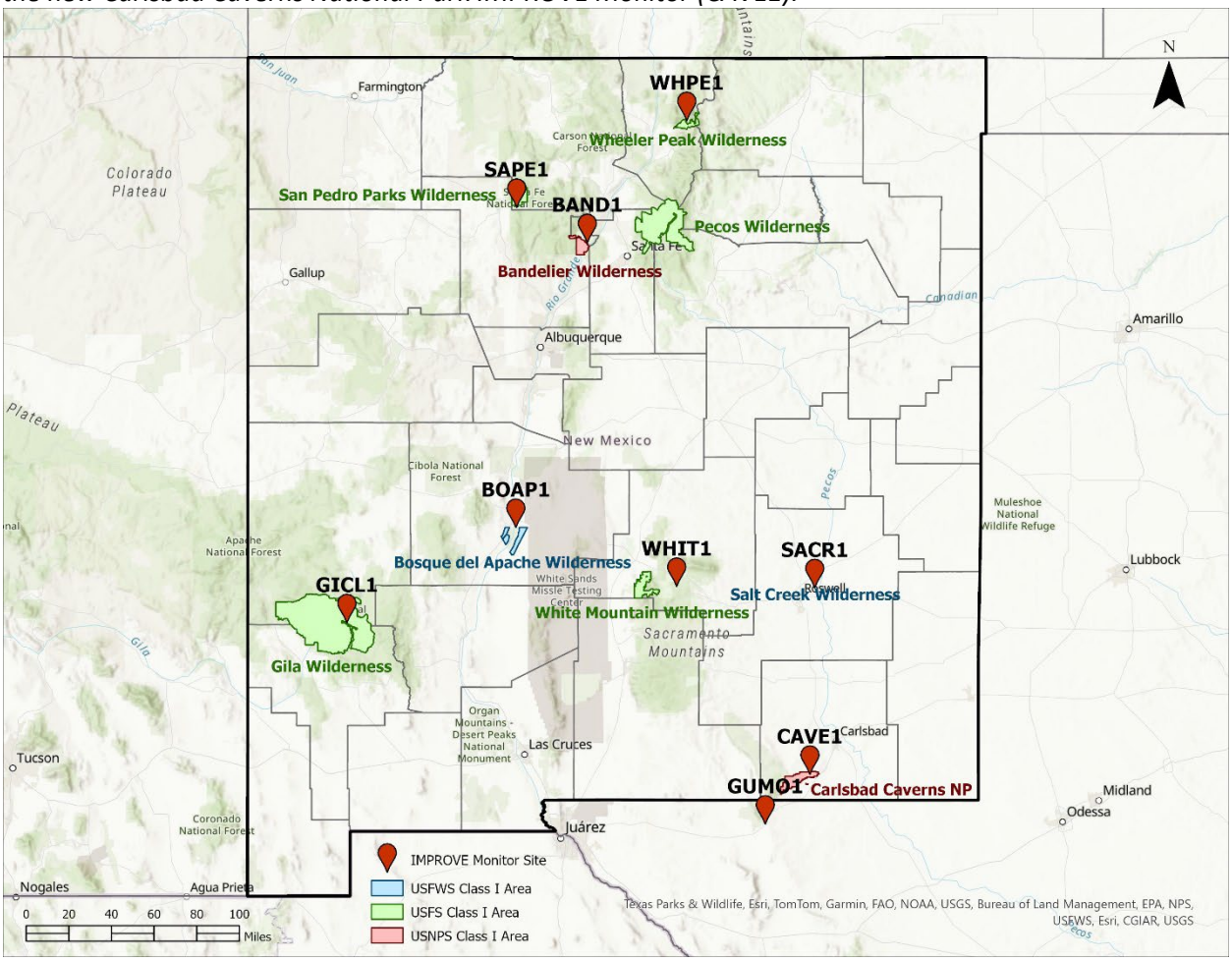
There are eight IMPROVE monitors in New Mexico and one in Texas that provide visibility information for New Mexico's Class I Areas. These monitors and the New Mexico Class I Areas they represent are listed in Table 12-1 below, and their locations are shown in Figure 12-1. The WHPE1 monitor provides data for both the Pecos Wilderness Area and Wheeler Peak Wilderness Area. The GUMO1 monitor provided visibility monitoring information for Carlsbad Caverns National Park prior to the establishment of the CAVE1 monitor in 2017.

[196] WESTAR members include the air quality program managers from the 15 westernmost states: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming.
[197] Ibid. Page 25 of 31.
[198] EPA Regional Haze SIP Guidance, p. 55.

Table 12-1: IMPROVE Monitors Representing New Mexico's Class I Areas.

IMPROVE Monitor	Class I Area(s) Represented	Federal Land Manager
SAPE1	San Pedro Parks Wilderness Area	USFS
WHPE1	Pecos Wilderness Area & Wheeler Peak Wilderness Area	USFS
BAND1	Bandelier Wilderness Area	NPS
BOAP1	Bosque del Apache Wilderness Area	USFWS
WHIT1	White Mountain Wilderness Area	USFS
SACR1	Salt Creek Wilderness Area	USFWS
GICL1	Gila Wilderness Area	USFS
CAVE1	Carlsbad Caverns National Park	NPS
GUMO1 (Texas)	Carlsbad Caverns National Park	NPS

Figure 12-1: Map Showing IMPROVE Monitor Sites Representing New Mexico's Class I Areas, Including the new Carlsbad Caverns National Park IMPROVE Monitor (CAVE1).



12.3 Statewide Inventory of Emissions

The Regional Haze Rule requires that the implementation plan must also provide for "A statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal area. The inventory must include emissions for the most recent year for which data are available, and estimates of future projected emissions. The State must also include a commitment to update the inventory periodically." [199]

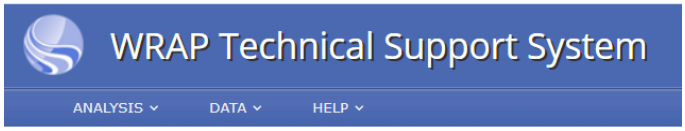
The State of New Mexico prepares annual and triennial emission inventories in compliance with the Consolidated Emissions Reporting Rule (CERR), promulgated by EPA in 2002 [200] and codified at 40 CFR Part 51 Subpart A, thereby satisfying the requirement to provide for the preparation of an emissions inventory for the most recent year for which data are available. [201] NMED will continue to submit annual inventories of pollutants, including those reasonably anticipated to cause or contribute to visibility impairment.

Estimates of future projected emissions for regional haze planning are typically developed by EPA and Multi-Jurisdictional Organizations such as the Western Regional Air Partnership (WRAP), with state coordination. For the second planning period WRAP developed several future year emissions inventory projections for western states that were made available publicly through the WRAP Technical Support System (TSS). [202]

[199] 40 CFR § 51.308(f)(6)(v).
[200] 67 Fed. Reg. 39602 (June 10, 2002)(Consolidated Emissions Reporting).
[201] EPA Regional Haze SIP Guidance, p. 55.
[202] The WRAP future year emissions inventory projections are described in the Emissions Methods, Results, and References document, available on the WRAP TSS at https://views.cira.colostate.edu/tssv2/Docs/WRAP_TSS_emissions_reference_final_20210930.pdf

Appendix A: WRAP Technical Support System for Regional Haze Planning: Emissions Methods, Results, and References







WRAP Technical Support System for Regional Haze Planning:

Emissions Methods, Results, and References

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1.0 Purpose:

The Western Regional Air Partnership and Western Air Quality Study (WRAP-WAQS) 2014 Regional Haze modeling platform is the latest of a series of regional modeling efforts supporting western U.S. air quality planning and management. The WRAP technical analyses follow the Environmental Protection Agency's (EPA) Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze (November 2018) and the Technical Support Document for EPA's updated 2028 regional haze modeling (September 2019). The analyses fulfill the objectives of the WRAP 2018-2019 Workplan as updated and approved by the WRAP Board on April 3, 2019 and have been collectively designed, implemented, and reviewed by the WRAP Technical Steering Committee and its workgroups and subcommittees.

The Western Regional Air Partnership (WRAP) Technical Support System (TSS) hosts the visibility monitoring, emissions, and air quality modeling analyses that support the 15 western states in developing regional haze state implementation plans (SIPs). This reference document describes the WRAP emissions and modeling analyses and illustrates how the TSS products can be applied and interpreted to support the 2028 visibility progress demonstrations for western U.S. Class I areas.

2.0 Background:

The Regional Haze Rule requires states to demonstrate progress every ten years toward the Clean Air Act goal of no manmade visibility impairment. EPA guidance for tracking visibility progress (December 2018) defines a visibility impairment tracking metric (measured in deciview) using observations from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring network sites that represent Class I areas. EPA defined in the Regional Haze Rule and guidance a Uniform Rate of Progress glidepath for the 20% most impaired days as the straight line from the 2000-2004 IMPROVE 5-year average baseline to EPA estimates of future natural visibility conditions, plotted at 2064. In the first regional haze planning period, 2000-2018, EPA guidance interpreted most impaired days as those days with highest total haze. States were required to demonstrate visibility progress by 2018 compared to the Uniform Rate of Progress glidepath for the haziest days and no degradation of visibility on the clearest days from the 2000-2004 IMPROVE 5-year average baseline. Visibility on the clearest days improved between 2000 and 2018 across the Class I areas in the western U.S. However, smoke from wildfire and wildland prescribed fire events and dust events on the haziest days made tracking the visibility benefits due to reducing U.S. anthropogenic emissions more difficult.

For the second regional haze implementation period, 2018-2028, states are required to demonstrate visibility progress by 2028 for the most impaired days and no visibility degradation for the clearest days. EPA guidance (December 2018) defined most impaired days as those days

with the highest fractional contribution to aerosol light extinction from anthropogenic sources. EPA statistical methods use IMPROVE measurements of carbon and crustal materials to separate contributions from episodic extreme natural events (e.g., wildfire or dust) from routine natural and anthropogenic contributions. Ammonium sulfate and ammonium nitrate are assigned primarily to anthropogenic emissions with smaller contributions from routine natural sources. This statistical approach does not separate contributions due to U.S. anthropogenic emissions from those of international anthropogenic emissions. Since states do not have authority to reduce international emissions, WRAP conducted source apportionment modeling analyses to evaluate U.S. anthropogenic contributions to haze and progress in reducing U.S. anthropogenic contributions to haze over time.

Table 1 summarizes the emissions and modeling scenarios, source apportionment runs, and alternative visibility progress analyses that were performed to support state regional haze planning.

Table 1. WESTAR-WRAP Emissions and Modeling Scenarios – update of January 18, 2021
Intermountain West Data Warehouse (IWDW) and Technical Support System (TSS) displays

Scenario Name	**Model Performance Evaluation** (2014v2 actual emissions / BCs and meteorology)	**Planning – Baseline** (mix of emissions inputs 2014-18 with 2014 meteorology)	**Planning – 2028 Projections** (2014 meteorology)	**Alternative Methods: 2028 Projections, Glidepath Endpoints, and Rate of Progress**	**Alternate Outcome Scenarios** (2014meteorology)
IWDW	Display emissions, model results, and site-level MPE results)	Display emissions and model results	Display emissions and model results		
TSS	Display emissions and model results	Display emissions and model results	Calculate and Display 2028 RPGs Display emissions and model results	Display alternative 2028 projections, glidepath endpoints, rate of progress	Calculate and Display 2028 RPGs. Display emissions and model results
Purpose	**Compare 2014v2 to RepBase2**	**Compare to RepBase2 to 2014v2, 2028OTBa2, 2028PAC2**	**Compare 2028OTBa2 to Repbase2, 2028PAC2, 2028FFS1, 2028FFS2**	**Focus on contributions of US anthropogenic emissions**	**Evaluate state source contributions and future fire scenarios**
CAMx Modeling Scenarios	**2014v2**	**RepBase2** Current Baseline (w/ RepFire). High-level CAMx PSAT source apportionment*	**2028OTBa2** (w/ RepFire) ** High-level PSAT source apportionment	**3 projection methods:** EPA default MID EPA MID w/o fires Modeled MID	**2028OTBa2 w/ SOxNOx PSAT** low-level (state by source sector contributions)
			2028PAC2 PotentialAddtlControls	Alternative 2064 glidepath endpoints	**2028FF1** Future Fire Sensitivity 1: Wildfire ****
			2028Adopted AddtlControls ***	U.S. Anthropogenic Modeled Rate of Visibility Progress ******	**2028FF2** Future Fire Sensitivity 2: WildlandRxFire *****

* 2014 International Anthro contribution adjustment option available from this modeling scenario (by difference)
** RepBase fires applied to 2028OTBa2
*** controls adopted by states in SIPs, this scenario is likely not possible until 2021 (*unfunded at present, not in Workplan*)
**** fire not paired in space or time with 2014 or RepFire activity, these sensitivity scenarios could give potential future wildfire contribution relative to 2028OTBa2
***** fire *is* paired in space *and* time with RepFire activity; this sensitivity scenario gives potential future Wildland Prescribed fire contribution relative to 2028OTBa2
******Dynamic Evaluation compare US anthropogenic contributions for 2002 Hindcast, RepBase2, and 2028OTBa2 to demonstrate alternative rate of visibility improvement

3.0 Emissions Scenarios:

2014v2 Base Year for WRAP Regional Haze Modeling

The WRAP 2014v2 inventory was based on the 2014v2 National Emissions Inventory (NEI) plus updates provided by western states through WRAP Regional Haze workgroup's Emissions and Modeling Protocol subcommittee.

Table 2 defines the WRAP 2014v2 sector-specific data sources. WRAP states replaced the 2014v2 NEI source sectors as listed below:

- California Air Resources Board (CARB) provided emissions for all anthropogenic sectors in California.
- WRAP states updated emissions for electric generating units (EGU), non-EGU point sources, and onroad mobile.
- The WRAP Oil and Gas Workgroup and its contractor Ramboll, Inc., defined a Roadmap for updating oil and gas inventories and delivered updated 2014 emissions (October 2018) for Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming (emissions for remaining WRAP states remain as in the EPA 2014v2 platform).
- The WRAP Fire and Smoke Work Group (FSWG) updated the 2014NEIv2 BlueSky/SmartFire emissions.
- Natural emissions were developed by WRAP for 2014v2 and held constant at 2014v2 levels for the Representative Baseline and future year scenarios.
- All other WRAP emissions sectors and all Non-WRAP emissions for WRAP 2014v2 were based on the EPA 2014 modeling platform.

Table 2. Data sources for WRAP emissions sectors for the 12-km 12WUS2 and 36-km US domains for the 2014v2, Representative Baseline (RepBase2) and 2028OTBa2 model scenarios.

Source Sector	2014v2	RepBase2	2028OTBa2
California All Sectors 12WUS2	CARB-2014v2	CARB-2014v2	CARB-2028
WRAP Fossil EGU w/ CEM	WRAP-2014v2	WRAP-RB-EGU [1]	WRAP-2028-EGU [1]
WRAP Fossil EGU w/o CEM	EPA-2014v2	WRAP-RB-EGU [1]	WRAP-2028-EGU [1]
WRAP Non-Fossil EGU	EPA-2014v2	EPA-2016v1	EPA-2028v1
Non-WRAP EGU	EPA-2014v2	EPA-2016v1	EPA-2028v1
O&G WRAP O&G States	WRAP-2014v2	WRAP-RB-O&G [2]	WRAP-2028-O&G [2]
O&G WRAP Other States	EPA-2014v2	EPA-2016v1	EPA-2016v1 [3]
O&G non-WRAP States	EPA-2014v2	EPA-2016v1	EPA-2016v1 [3]
WRAP Non-EGU Point	WRAP-2014v2	WRAP-2014v2 [4]	WRAP-2014v2 [4]
Non-WRAP non-EGU Point	EPA-2014v2	EPA-2016v1	EPA-2016v1
On-Road Mobile 12WUS2	WRAP-2014v2	WRAP-2014v2	WRAP-2028-Mobile [5]
On-Road Mobile 36US	EPA-2014v2	EPA-2016v1	EPA-2028v1
Non-Road 12WUS2	EPA-2014v2	EPA-2016v1	WRAP-2028-Mobile [5]
Non-Road non-WRAP 36US	EPA-2014v2	EPA-2016v1 [6]	EPA-2028v1 [6]
Other (Non-Point) 12WUS2	EPA-2014v2	EPA-2014v2 [7]	EPA-2014v2 [7]
Other (Non-Point) 36US	EPA-2014v2	EPA-2016v1	EPA-2016v1
Can/Mex/Offshore 12WUS2	EPA-2014v2	EPA-2016v1	EPA-2016v1
Fires (WF, Rx, Ag)	WRAP-2014-Fires	WRAP-RB-Fires [8]	WRAP-RB-Fires [8]
Natural (Bio, etc.)	WRAP-2014v2	WRAP-2014v2	WRAP-2014v2
Boundary Conditions (BCs)	WRAP-2014-GEOS	WRAP-2014-GEOS	WRAP-2014-GEOS

1. WRAP-RepBase2-EGU and WRAP-2028OTBa2-EGU include changes/corrections/updates from WESTAR-WRAP states
2. WRAP-RepBase2-O&G and WRAP-2028OTBa2-O&G both include corrections for WESTAR-WRAP states.
3. O&G for other WRAP states and Non-WRAP states use EPA-2016v1 assumptions for 2028OTBa2 and unit-level changes provided by WESTAR-WRAP states.
4. WRAP-2014v2 Non-EGU Point is used for RepBase2 and 2028OTBa2, with source specific updates provided by WESTAR-WRAP states.
5. WRAP-2028-MOBILE is used for On-Road and Non-Road sources for the 12WUS2 domain.
6. EPA-2016v1 and EPA-2028v1 are used for On-Road and Non-Road Mobile for the 36km US domain.
7. Non-Point emissions use 2014v2 emissions for RepBase2 and 2028OTBa2 scenarios, including state-provided corrections.
8. RepBase fires are used for both RepBase2 and 2028OTBa2

Representative Baseline (RepBase2)

The Representative Baseline (RepBase2) emissions scenario updates the 2014v2 inventory to account for changes and variation in emissions between 2014 and 2018 for key WRAP source sectors, as defined by the WRAP Emissions and Modeling Protocol subcommittee. The RepBase inventory was delivered in February 2020 as listed below.

- California Air Resources Board (CARB) used the same source sector emissions as defined for 2014v2.
- The WRAP EGU Emissions Analysis Project developed a comprehensive database for fossil fuel electric generating units in 13 continental western states, including operating characteristics and emissions, for the period circa 2014-2018. Methods are defined in Center for New Energy Economy's analysis of WRAP fossil-fueled Electric Generating Units for Regional Haze Planning and Ozone Transport Contribution (June 2019.)
- The WRAP Oil and Gas Workgroup and its contractor, Ramboll, Inc., developed the circa-2014 baseline oil and gas inventory to apply to the RepBase inventory.
- The WRAP Fire and Smoke Work Group (FSWG) worked with states, tribes, federal land managers and Air Sciences, Inc., to define 2014 to 2018 wildfire emissions for the Continental U.S. (36-km modeling grid) to represent a broader range of fire conditions (Representative Fire) than the single year 2014, as reported in Fire Emissions Inventories for Regional Haze Planning: Methods and Results (April 2020).
- All other emissions sectors used the EPA 2016v1 platform for RepBase.

During state review of the Representative Baseline emissions, some errors and duplicate records were identified. WRAP states revised select EGU, non-EGU point, and oil and gas emissions for a revised Representative Baseline (RepBase2). Data sources for RepBase2 emissions, as delivered in September 2020, are defined in **Table 2.** Emissions sectors that changed between 2014v2 and RepBase2 are defined in **Table 4**.

The RepBase2 WRAP Point source emissions are available to download on the WRAP Regional Haze Planning Work Group webpage. Note that these point source emissions files are not identical to the SMOKE emissions model outputs that are posted on the TSS.

WRAP methods are further defined in Ramboll Inc.'s Run Specification Sheet for Representative Baseline (RepBase2) and 2028 On-the-Books (2028OTBa2) CAMx Simulations.

2028 On the Books Inventory (2028OTBa2)

The WRAP 2028OTBa emissions inventory projection followed the methods applied by EPA in the September 2019 Technical Support Document for updated 2028 regional haze modeling. The WRAP states updated source sectors to account for implementation by 2028 of all applicable federal and state requirements for U.S. anthropogenic emissions as listed below:

- California Air Resources Board (CARB) provided 2028OTB projections from 2014v2 for all anthropogenic source sectors.

- WRAP states worked with western utilities and the Center for New Energy Economy to project EGU emissions for 2028 On the Books, as reported in Analysis of EGU Emissions for Regional Haze Planning and Ozone Transport Contribution (June 2019).

- The WRAP Oil and Gas workgroup and its contractor, Ramboll, Inc., projected 2028 Oil and Gas area and point source emissions for WRAP states as reported in Revised Final Report: 2028 Future Year Oil and Gas Emission Inventory for WESTAR-WRAP States, March 2020 version.

  Table 3. 2028 On the Books Oil and Gas emissions by WESTAR-WRAP State split into Tribal and Non-Tribal mineral ownership, for Nitrogen Oxides and Volatile Organic Compounds (tons/year) from Revised Final Report: 2028 Future Year Oil and Gas Emission Inventory for WESTAR-WRAP States, March 2020

State	NOx Emissions (tons/year)		VOC Emissions (tons/year)	
	Non-tribal	Tribal	Non-tribal	Tribal
AK	37,663	-	23,880	-
AZ	1,960	-	280	-
CO	28,580	14,970	75,122	2,214
ID	889	-	34	-
MT	4,843	290	28,048	1,217
ND	64,306	9,053	274,187	45,480
NM	90,658	3,592	219,765	8,568
NV	156	-	269	-
OR	454	-	73	-
SD	763	-	4,786	-
UT	4,812	5,739	15,770	52,108
WA	444	-	36	-
WY	24,162	171	109,152	438
Total	**259,690**	**33,815**	**751,403**	**110,023**

- WRAP 2028 CAMx-ready emissions for on-road and non-road mobile sources, including off-shore shipping, rail and airports are reported in Mobile Source Emissions Inventory 2028 Projections Project.

- Wildfire, Wildland Prescribed fire, and agricultural fires for the 2028OTBa inventory were identical to RepBase fires.

In September 2020, the WRAP states made revisions to select EGU, non-EGU, and oil and gas emissions for the WRAP states in the updated 2028OTBa2 projection. EPA 2016v1 emissions were

assigned to some source sectors for WRAP, non-WRAP, Canada and Mexico in lieu of EPA 2028v1 emissions to provide more conservative assumptions for the 2028OTBa2 projection. 2028OTBa2 data sources are listed in **Table 2** and 2028OTBa2 emissions sectors that changed emissions compared to RepBase2 are listed in **Table 4**.

Table 4: WRAP Emissions Data Sources across WRAP Modeling Scenarios

TSS Sector Name	TSS Selection Menu Label	WRAP Representative Base2 data source	WRAP Rep Base2 changes from 2014v2	WRAP 2028OTBa2 changes from RepBase2	WRAP 2028OTBa2 +PAC2 changes	WRAP 2028OTBa2 +Wildfire changes	WRAP 2028OTBa2 +Wildland Prescribed fire changes
California All Sectors		CARB-2014v2[1]		X	X		
Electric Generating Units (EGU)	**pt_egu**	WRAP-RB-EGU[2]	X	X[8]	X		
Oil&Gas- point -WRAP O&G states	**pt_oilgas**	WRAP-RB-O&G[3]	X	X[8]	X		
Oil&Gas - point - WRAP other states		EPA-2016v1[4]	X	X[8]	X		
Industrial and Non-EGU Point	**pt_nonegu**	EPA-2014v2[5]	X	X[8]	X		
Oil&Gas - nonpoint -WRAP O&G states	**np_oilgas**	WRAP-RB-O&G[3]					
Oil&Gas - nonpoint -WRAP other states		EPA-2016v1[4]					
Residential Wood Combustion	**rwc**	EPA-2014v2[5]		-			
Fugitive Dust	**afdust**	EPA-2014v2[5]					
Agriculture	**ag**	EPA-2014v2[5]					
Remaining Nonpoint	**nonpt**	EPA-2014v2[5]					
On-road Mobile	**onroad**	WRAP-2014v2[6]	X	X	CA only		
Non-road Mobile	**nonroad**	EPA-2016v1[4]	X	X			
Rail	**rail**	EPA-2014v2[5]		X			
Commercial Marine	**cmv_c1c2c3**	EPA-2016v1[4]	X	X			
Agricultural Fire	**ag-flaming**	WRAP-2014v2[6]					
Wildland Prescribed Fire	**rxfire**	WRAP-RB-fires[7]	X				X
Wildfire	**wildfire**	WRAP-RB-fires[7]	X			X	
Biogenic	**biogenic**	WRAP-2014v2[6]					
Other non-WRAP 12WUS2, 36US		EPA-2016v1[4]	X	X			

WRAP methods are further defined in the Run Specification Sheet for Representative Baseline (RepBase2) and 2028 On-the-Books (2028OTBa2) CAMx Simulations. Note that these point source emissions files are not identical to the SMOKE emissions model outputs that are posted on the TSS. Also, point sources on Tribal lands are listed separately from state point sources.

The 2028OTBa2 WRAP Point source emissions are available to download on the WRAP Regional Haze Planning Work Group (wrapair2.org) webpage. Note that these point source emissions files are not identical to the SMOKE emissions model outputs that are posted on the TSS.

2028 Potential Additional Controls (PAC2)

Some, but not all, western states defined Potential Additional Controls beyond the On the Books controls to evaluate the potential visibility response in 2028. The states and source categories for additional potential controls are defined in **Table 5**.

Table 5. WESTAR-WRAP States and source sectors modified in the 2028 Potential Additional Controls (PAC2) modeling scenario compared to 2028OTBa2.

2028PAC2 changes to 2028OTBa2	AZ	CA	CO	ID	MT	NV	NM	ND	OR	SD	UT	WA	WY
EGU - point	x				x	x	x	x	x				
Non-EGU point				x		x	x		x			x	
O&G- point	x						x		x				
On-road Mobile		x											

Point source emissions spreadsheets for the 2028OTBa2 and PAC2 emissions scenarios, after data review by WESTAR-WRAP states completed October 9,2020, are found on the WRAP Regional Haze Planning Workgroup webpage.

Future Wildfire Sensitivity 1

In addition to the 2014v2 and Representative Baseline/2028 On the Books fire scenarios, the WRAP Fire and Smoke Work Group (FSWG) defined a future wildfire sensitivity (FFS1) (not specific to any single future year) as an alternative to using 2014-2018 wildfire activity data for 2028 visibility projections. The future wildfire emissions are used with 2028OTBa2 emissions for all other emissions sectors.

Modeling a range of future fire emissions will help visualize potential future impacts from this sector. The purposes of this sensitivity are to determine:

- how changes in wildfire activity change the projected 2028 visibility response to US anthropogenic emissions using the regional haze tracking metric
- monthly variation in future wildfire impacts compared to the 2028OTBa2 reference case.

Methods for the future wildfire sensitivity (FFS1) are described in Air Sciences' report Fire Emissions Inventories for Regional Haze Planning: Methods and Results (April 2020) and summarized in the modeling Specification Sheet for Future Fire Sensitivities (August 2021). As summarized in **Table 6**, future wildfire acreage and emissions may be greater than or less than those of the RepBase2/2028OTBa2 emissions scenarios. Emissions from wildland prescribed fire and agricultural burns were the same in FFS1 as for the RepBase2/2028OTBa2 scenarios.

Table 6. Comparison of fire emissions in continental WESTAR-WRAP states for the Wildfire (FFS1) modeling sensitivity, relative to the RepBase2/2028OTBa2 scenarios by fire event, acres burned, tons of fuel consumed, and $PM_{2.5}$ emissions, as well as differences in percent.

	Wildfire (FFS1)				RepBase2 / 2028OTBa2				Percent Difference			
State	Events	Acres	Tons Fuel Consumed	Tons $PM_{2.5}$	Events	Acres	Tons Fuel Consumed	Tons $PM_{2.5}$	Events	Acres	Tons Fuel Consumed	Tons $PM_{2.5}$
AZ	2,461	278,146	565,862	7,168	2,810	219,779	554,371	7,238	-12%	27%	2%	-1%
CA	6,502	1,058,201	29,353,059	434,630	7,004	822,112	30,274,941	450,970	-7%	29%	-3%	-4%
CO	1,816	88,746	1,343,955	19,970	2,103	209,106	6,014,389	89,965	-14%	-58%	-78%	-78%
ID	1,908	350,939	1,333,867	17,495	2,082	331,911	2,977,946	42,601	-8%	6%	-55%	-59%
MT	3,016	585,817	5,645,173	75,799	3,443	345,932	3,368,691	43,866	-12%	69%	68%	73%
NV	1,233	221,413	730,140	9,169	1,540	268,607	643,098	7,437	-20%	-18%	14%	23%
NM	3,298	914,977	1,116,799	11,131	4,418	543,192	893,910	9,760	-25%	68%	25%	14%
ND	317	7,582	89,675	784	377	8,007	90,876	774	-16%	-5%	-1%	1%
OR	2,453	822,417	16,240,735	239,672	2,583	558,944	10,731,358	157,441	-5%	47%	51%	52%
SD	740	292,610	4,146,708	43,847	891	321,681	4,649,179	49,242	-17%	-9%	-11%	-11%
UT	1,194	478,045	1,771,838	24,057	1,382	295,023	1,257,384	17,174	-14%	62%	41%	40%
WA	1,500	243,934	12,817,841	192,062	1,566	184,553	9,378,215	140,516	-4%	32%	37%	37%
WY	2,187	347,097	1,065,757	10,175	2,478	367,253	1,098,031	10,982	-12%	-5%	-3%	-7%
Total	28,625	5,689,923	76,221,409	1,085,959	32,677	4,476,101	71,932,389	1,027,966	-12%	27%	6%	6%

Future Wildland Prescribed Fire Sensitivity 2

The WRAP Fire and Smoke workgroup defined a no-year future wildland prescribed fire sensitivity (FFS2) as an alternative to using 2014-2018 RepBase2 activity data for 2028 visibility projections.

U.S. land management agencies intend to increase the acres burned by wildland prescribed fire in future years to reduce the vegetation that fuels high-intensity wildfires. The purposes of this sensitivity were to determine:

- how changes in wildland prescribed fire could change the 2028 visibility projections that are used in regional haze planning.
- monthly variation in future wildfire impacts compared to the 2028OTBa2 reference case.

Methods for the future wildland prescribed fire sensitivity (FFS2) are described in Air Sciences' report Fire Emissions Inventories for Regional Haze Planning: Methods and Results (April 2020) and summarized in the modeling Specification Sheet for Future Fire Sensitivities. The FFS2 wildland prescribed fire events were tied to the same geographic ecoregions and dates as the RepBase2 burns. The acreages of the FFS2 events were randomly selected and emissions were recalculated. As summarized in **Table 7**, future wildland prescribed fire acreage and emissions may be greater than or less than those defined for the RepBase2/2028OTBa2 emissions scenarios. Wildfire events and agricultural burns are held the same as for RepBase2/2028OTBa2 scenarios.

Table 7. Comparison of fire emissions in continental WESTAR-WRAP states for the Wildland Prescribed fire (FFS2) modeling sensitivity, relative to the RepBase2/2028OTBa2 scenarios by fire event, acres burned, tons of fuel consumed, $PM_{2.5}$ emissions, and percent differences.

	Prescribed Burning (FFS2)				RepBase2 / 2028OTBa2				Percent Difference			
State	Events	Acres	Tons Fuel Consumed	Tons $PM_{2.5}$	Events	Acres	Tons Fuel Consumed	Tons $PM_{2.5}$	Events	Acres	Tons Fuel Consumed	Tons $PM_{2.5}$
AZ	595	185,102	1,239,269	18,491	595	141,195	907,285	13,533	0%	31%	37%	37%
CA	993	184,688	3,280,671	48,672	993	130,965	2,197,780	32,518	0%	41%	49%	50%
CO	374	88,032	983,959	14,674	374	48,732	475,867	7,070	0%	81%	107%	108%
ID	1,824	268,469	3,600,038	53,594	1,824	137,990	1,905,385	28,367	0%	95%	89%	89%
MT	1,480	201,931	2,507,741	35,679	1,481	161,093	1,837,448	25,822	0%	25%	36%	38%
NV	95	22,369	130,444	1,872	95	16,270	72,430	1,013	0%	37%	80%	85%
NM	258	113,215	745,557	11,039	258	88,247	511,013	7,530	0%	28%	46%	47%
ND	214	47,591	232,775	2,375	214	39,193	197,939	2,013	0%	21%	18%	18%
OR	2,525	378,621	5,298,344	77,827	2,525	302,136	4,218,348	61,808	0%	25%	26%	26%
SD	394	112,840	2,287,843	33,795	394	64,568	1,062,962	15,449	0%	75%	115%	119%
UT	224	220,746	1,565,240	22,939	224	71,512	486,573	7,116	0%	209%	222%	222%
WA	1,278	147,728	1,890,834	28,087	1,278	123,228	1,540,525	22,864	0%	20%	23%	23%
WY	283	70,749	867,832	12,624	283	43,306	421,667	6,021	0%	63%	106%	110%
Total	10,537	2,042,079	24,630,545	361,670	10,538	1,368,436	15,835,221	231,125	0%	49%	56%	56%

2002 Hindcast Emissions

The purposes of the Dynamic Evaluation and 2002 Hindcast emissions were:

- test the CAMx 2014v2 model platform's ability to project observed air quality changes in response to observed emissions changes between the 2000-2004 baseline and the 2014-2018 (RepBase2) planning period at western U.S. IMPROVE monitors.
- evaluate U.S. Anthropogenic emissions rate of progress between 2002 and 2028OTBa2 to define a modeled U.S. Anthropogenic visibility rate of progress by 2028.

Methods for the 2002 Hindcast are described in the Run Specification Sheet for Dynamic Evaluation – 2002 CAMx Simulation and Analysis. TheRepBase2 emissions were hindcast to the 2002 base year using the current inventory methods and 2002 activity data. Natural and non-US emissions were held the same as RepBase2 so that all changes in air concentrations and visibility between 2002 and RepBase2 were attributable to changes in U.S. anthropogenic emissions.

Emission Scenarios Comparison:

Annual emissions (tons per year) for ammonia (NH3), carbon monoxide (CO), nitrogen oxides (NOx), particulate matter less than 2.5 micrometers (PM2.5), particulate matter less than 10 micrometers (PM10), sulfur dioxide (SO2), and volatile organic compounds (VOC) for 13 continental U.S. western states, 14 anthropogenic source groups, and 6 natural source categories for the 2014v2, RepBase2, 2028OTBa2, and 2028PAC2 emissions scenarios can be downloaded from the TSS Emissions Express Tools. The emissions data displayed on the Technical Support System are composited from more detailed pollutant emissions records (to be displayed on the Intermountain West Data Warehouse), as defined in **Table 8** below.

Table 8. Pollutant Emissions displayed on the WRAP Technical Support System and summarized on Intermountain West Data Warehouse.

Final – January 2021

Modeled Pollutant Emissions	Pollutant Code	Technical Support System (TSS) Pollutant Emissions	Pollutant Code
Carbon Monoxide	CO	Carbon Monoxide	CO
Nitrogen Oxides	NOx = NO+NO2+HONO	Nitrogen Oxides	NOx
Sulfur Dioxide	SO2	Sulfur Oxides	SO2
Volatile Organic Compound	VOC	Volatile Organic Compound	VOC
Ammonia	NH3	Ammonia	NH3
Sulfuric Acid	SULF		
Total Particulate Matter less than 2.5 mm (PM2.5)	PM2.5 = POA + PEC + PNO3 + PSO4 + PNH4 + Elements + FPRM	Total Particulate Matter less than 2.5 mm	PM2.5

Particulate Organic Carbon	POA		
Particulate Elemental Carbon	PEC		
Nitrate	PNO3		
Sulfate	PSO4		
Ammonium	PNH4		
Elements	PFE + PMN + PK + PCA + PMG + PAL + PSI + PTI		
"Remaining" Fine Particulate Matter	FPRM		
Coarse Particulate Matter	CPRM		
Particulate Matter less than 10 mm	CPRM + PM2.5	Particulate Matter less than 10 mm	PM10
Sea salt	PCL + NA		

Examples of emissions results that are displayed in TSS Emissions Express Tools # 1-4 are illustrated below.

2017 National Emissions Inventory (NEI) data also can be displayed in TSS Emissions Express Tools # 1-3.

- To display emissions values, below each chart # 1-3, select to show "+ chart data".

Figures 1a-1c illustrate NOx, SO2, and PM2.5 emissions, respectively, for all anthropogenic emissions sectors for WESTAR-WRAP states for the 2014v2, RepBase2, 2028OTBa2, and 2028PAC2 emission scenarios (TSS Emissions Express Tool # 1).

Figures 2a-2c illustrate NOx, SO2, and PM2.5 emissions, respectively, for Oil and Gas Point sources (one of 14 anthropogenic source sectors that can be selected for display) for WESTAR-WRAP states and the 2014v2, RepBase2, 2028OTBa2, and 2028PAC2 emission scenarios (TSS Emissions Express Tool # 2)**.**

Figures 3a-3d illustrate total NOx emissions for the 2014v2, RepBase2, and 2028OTBa2 scenarios, and the 2017 National Emissions Inventory, respectively, for the 13 continental WESTAR-WRAP states as pie charts of the 14 anthropogenic source sectors (TSS Emissions Express Tool # 3). SO2 and PM2.5 charts are similar format, not displayed in this document.

Tables 8 and 10 display State Emissions Totals (tons/year) for NOx and SO2, respectively, for 16 emissions sectors and the 2014v2, RepBase2, 2028OTBa2 and 2028PAC2 emissions scenarios (TSS Emissions Express Tool # 4).

Figure 1a. Annual Nitrogen oxide (NOx) emissions (tons per year) for the 13 continental WESTAR-WRAP states and 14 anthropogenic source groups for the 2014v2, RepBase2, 2028OTBa2, and 2028PAC2 scenarios. TSS Emissions Express Tool # 1.

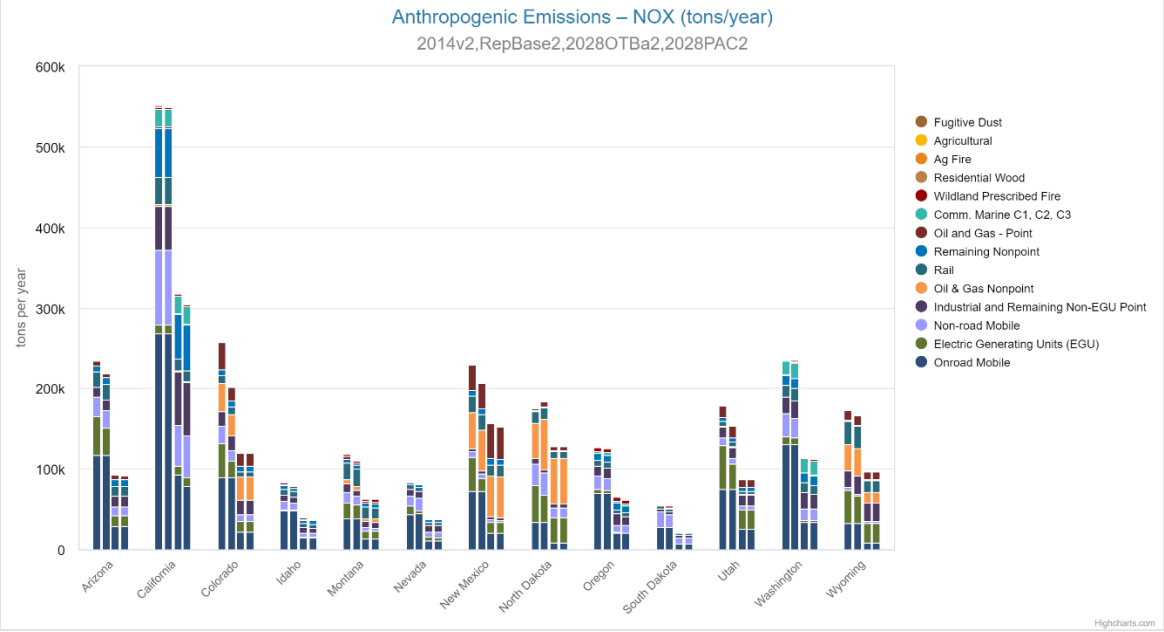


Figure 1b. Annual Sulfur dioxide (SO2) emissions (tons per year) for the 13 continental WESTAR-WRAP states and 14 anthropogenic source groups for the 2014v2, RepBase2, 2028OTBa2, and 2028PAC2 scenarios. TSS Emissions Express Tool # 1.

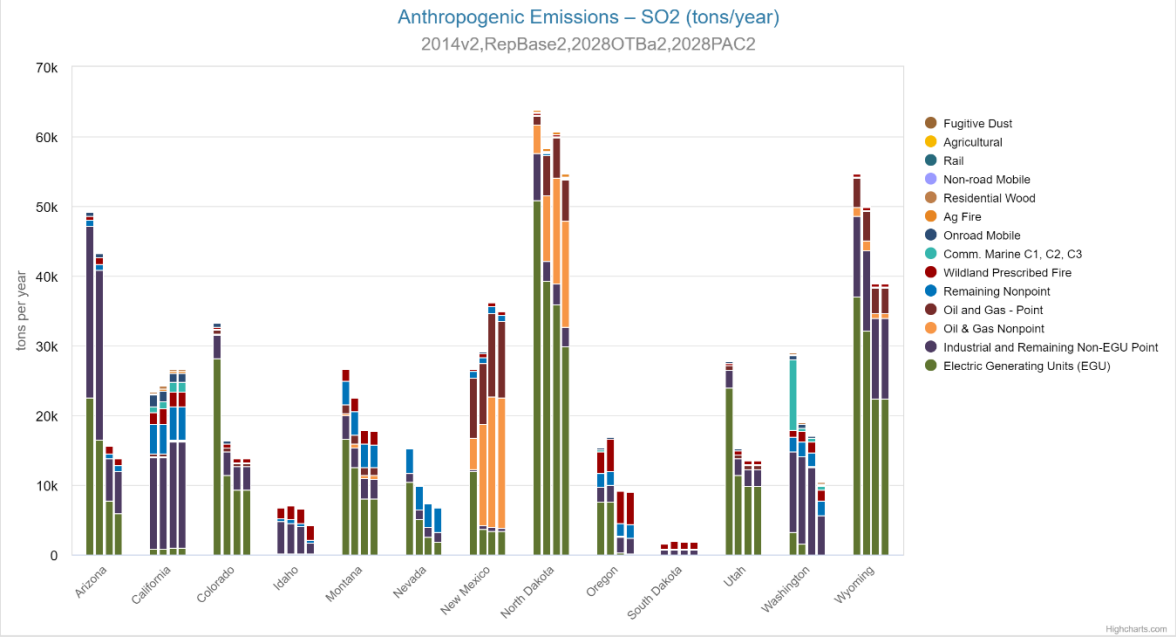


Figure 1c. Annual emissions (tons per year) for Particulate matter less than 2.5 micrometers (PM2.5) for the 13 continental WESTAR-WRAP states and 14 anthropogenic source groups for the 2014v2, RepBase2, 2028OTBa2, and 2028PAC2 scenarios. TSS Emissions Express Tool # 1.

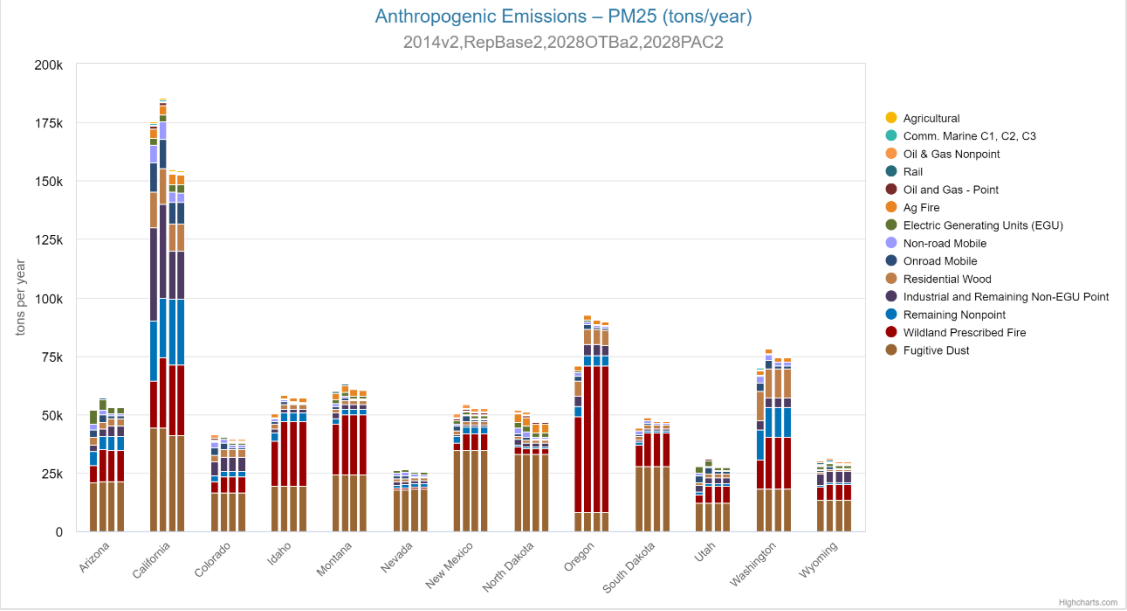


Figure 2a. Annual Nitrogen Oxide (NOx) emissions (tons per year) for Oil and Gas Point sources (1 of 14 anthropogenic source group selection options) in the 13 continental WESTAR-WRAP states for the 2014v2, RepBase2, 2028OTBa2, and 2028PAC2 scenarios. TSS Emissions Express Tool # 2.

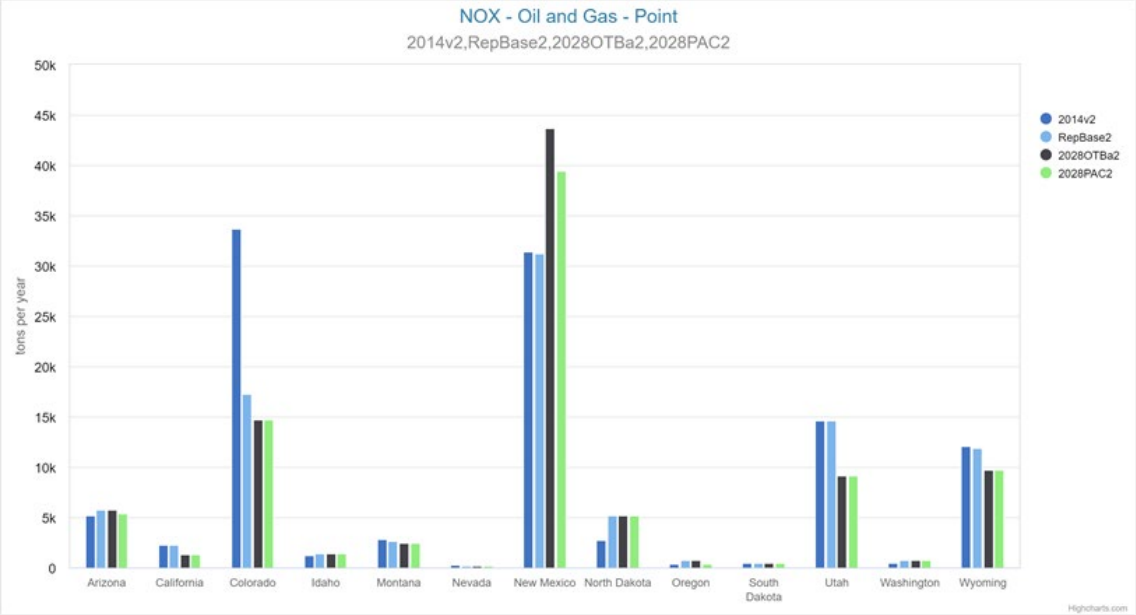


Figure 2b. Annual Sulfur dioxide (SO2) emissions (tons per year) for Oil and Gas Point sources (1 of 14 anthropogenic source group selection options) in the 13 continental WESTAR-WRAP states for the 2014v2, RepBase2, 2028OTBa2, and 2028PAC2 scenarios. [TSS Emissions Express Tool] # 2.

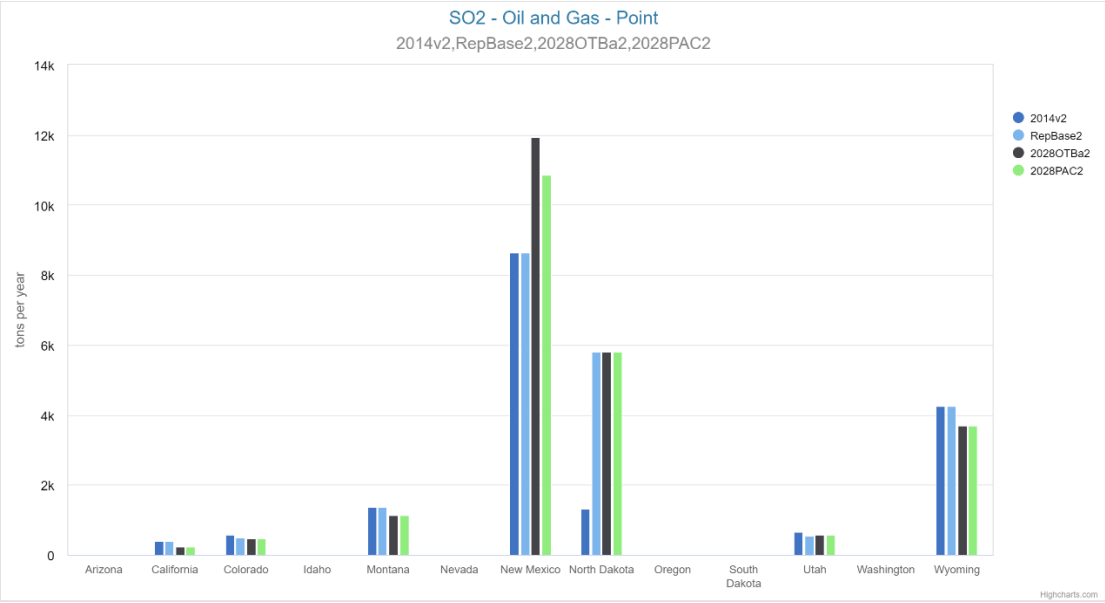


Figure 2c. Annual emissions (tons per year) for Particulate matter less than 2.5 micrometers (PM2.5) for Oil and Gas Point sources (1 of 14 anthropogenic source group selection options) in the 13 continental WESTAR-WRAP states for the 2014v2, RepBase2, 2028OTBa2, and 2028PAC2 scenarios. [TSS Emissions Express Tool] # 2.

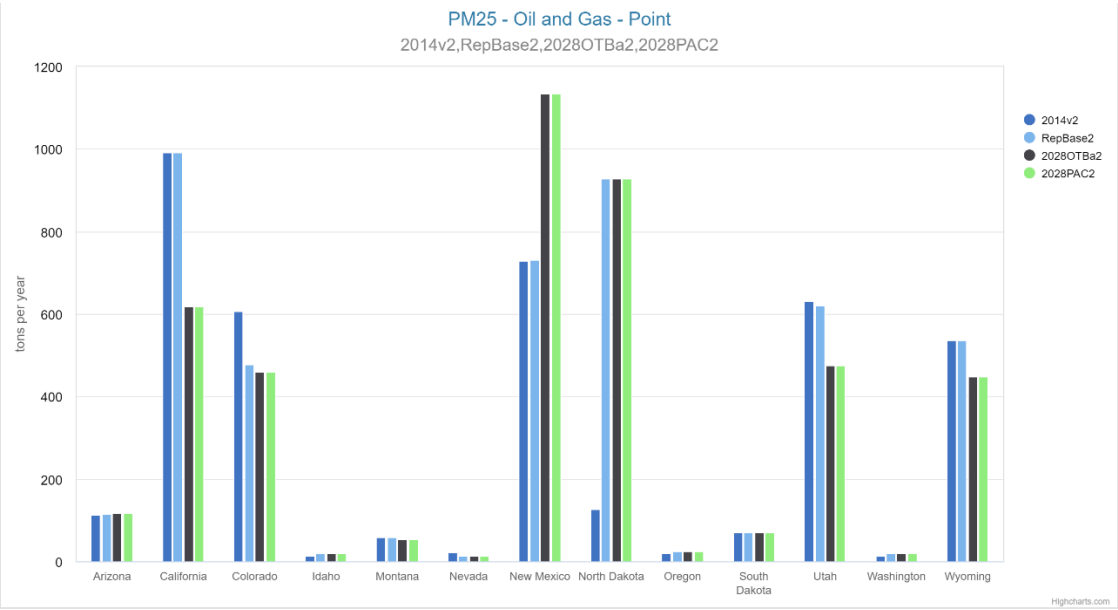


Figure 3a. 2014v2 annual Nitrogen oxide (NOx) emissions (tons per year) totaled for the 13 continental WESTAR-WRAP states for 14 anthropogenic source groups, [TSS Emissions Express Tool] # 3.

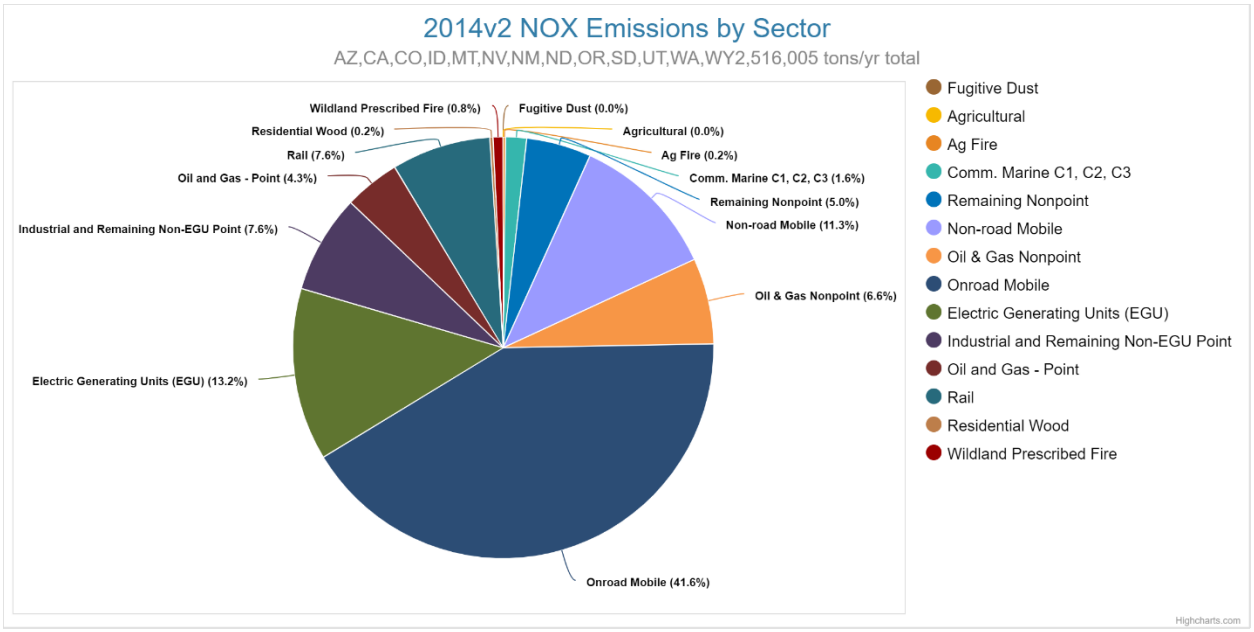


Figure 3b. Representative Baseline (RepBase2) annual Nitrogen oxide (NOx) emissions (tons per year) totaled for the 13 continental WESTAR-WRAP states for 14 anthropogenic source groups, [TSS Emissions Express Tool] # 3.

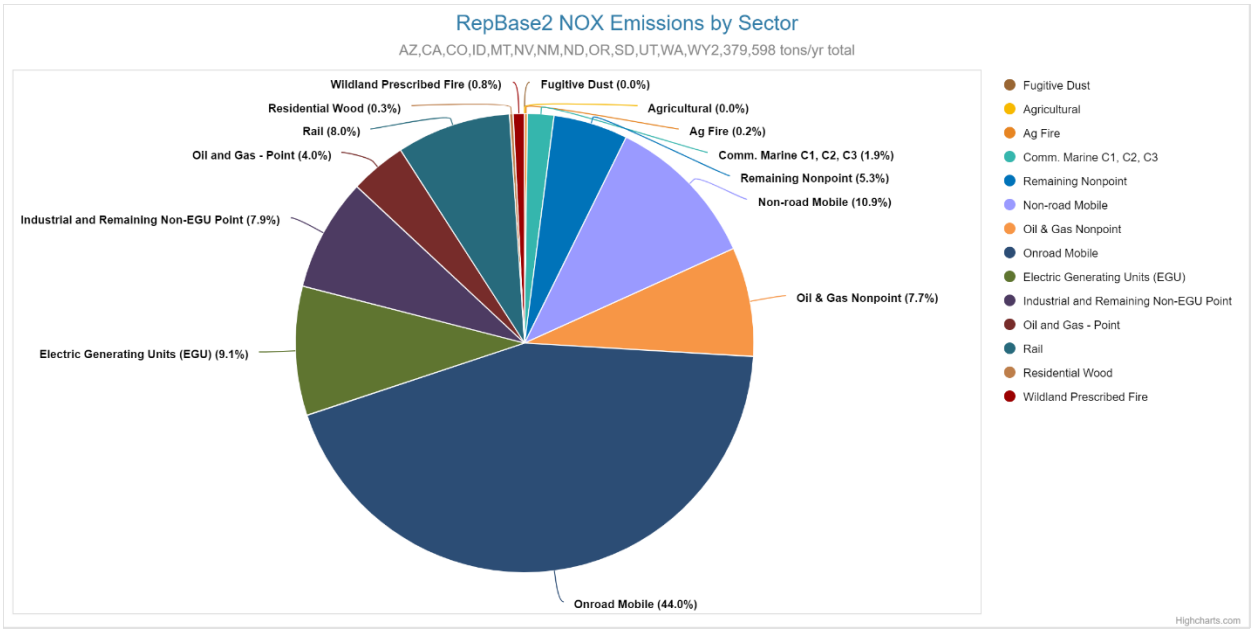


Figure 3c. 2028 On the Books (2O28OTBa2) annual Nitrogen oxide (NOx) emissions (tons per year) totaled for the 13 continental WESTAR-WRAP states for 14 anthropogenic source groups, [TSS Emissions Express Tool]# 3.

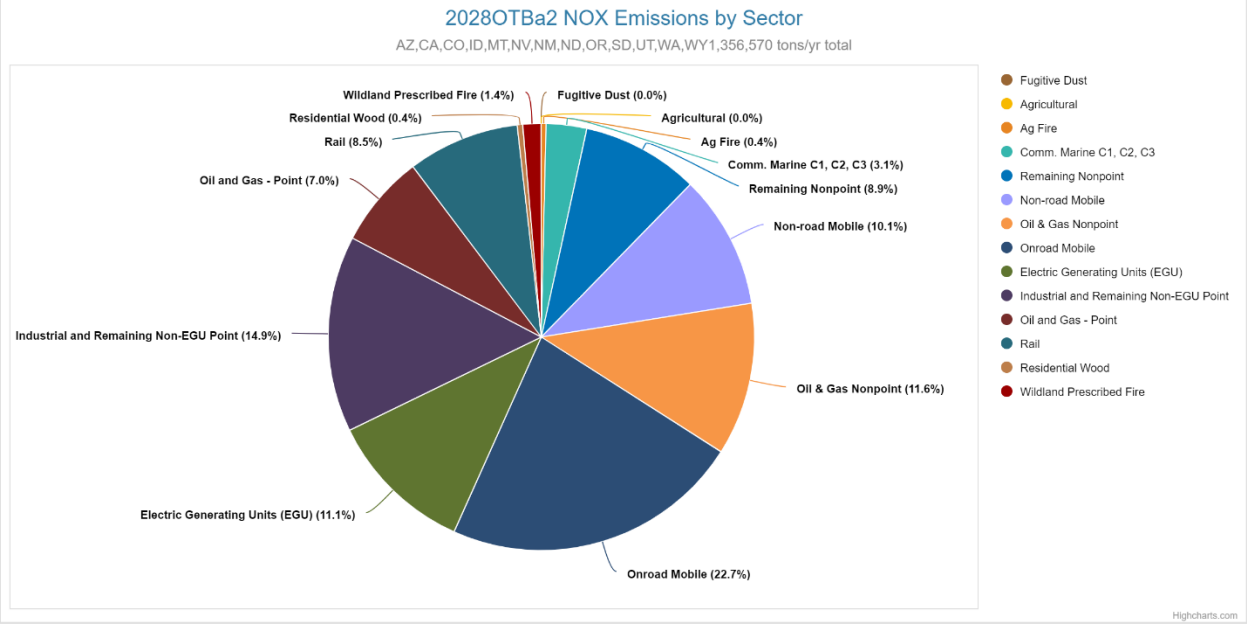


Figure 3d. National Emissions Inventory 2017 (NEI_2017) annual Nitrogen oxide (NOx) emissions (tons per year) totaled for the 13 continental WESTAR-WRAP states for 14 anthropogenic source groups, [TSS Emissions Express Tool]# 3.

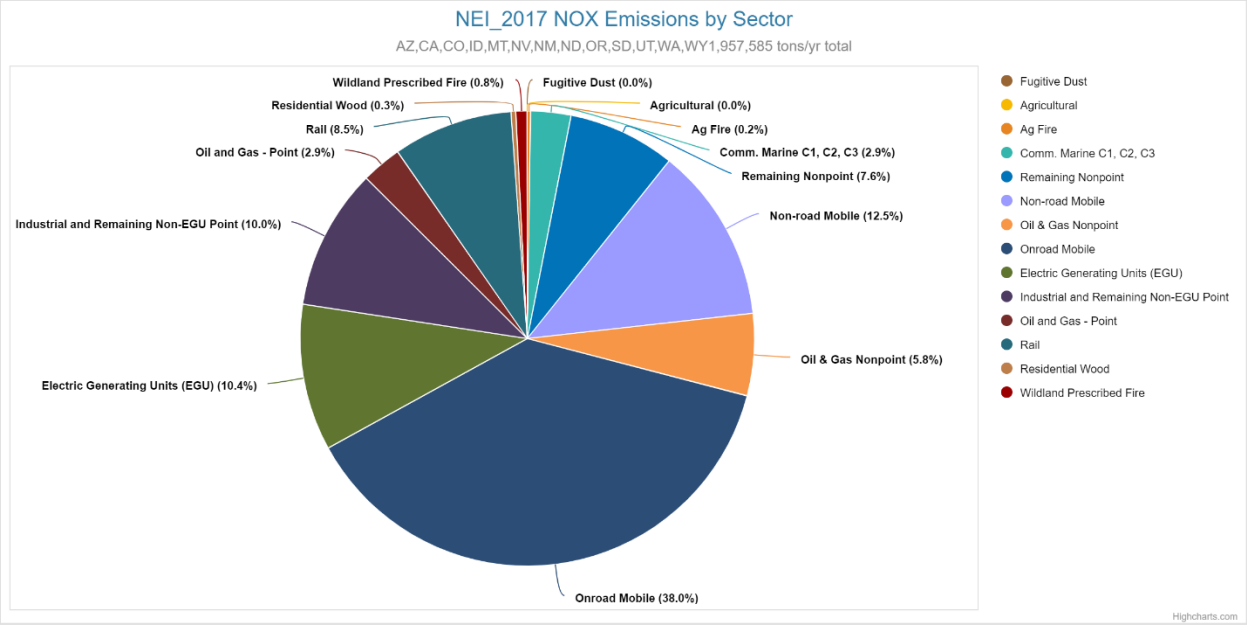


Table 9. Colorado Nitrogen oxide (NOx) emissions (tons/year) for 2014v2, Representative Baseline 2, 2028 On the Books (2028OTBa2), and 2028 Potential Additional Controls (2028PAC2) scenarios and 16 emissions sectors TSS Emissions Express Tool #4.

State: **Colorado**

Pollutant: **Nitrogen Oxides (NOx)** tons/year

State Emissions	Source Category	2014v2 Actual	Representative Baseline 2	2028 OTB a2 [1]	2028 PAC2
Anthropogenic	Electric Generating Units (EGU)	41,596	19,854	13,356	13,356
Anthropogenic	Oil and Gas - Point	33,694	17,226	14,677	14,677
Anthropogenic	Industrial and Non-EGU Point	17,613	17,686	18,007	18,007
Anthropogenic	Oil and Gas - Non-point	35,373	26,987	29,062	29,062
Anthropogenic	Residential Wood Combustion	446	446	446	446
Anthropogenic	Fugitive dust [3]	0	0	0	0
Anthropogenic	Agriculture [2]	0	0	0	0
Anthropogenic	Remaining Non-point	7,209	7,209	7,209	7,209
Anthropogenic	On-Road Mobile	89,776	89,776	22,097	22,097
Anthropogenic	Non-road Mobile	22,355	13,463	8,462	8,462
Anthropogenic	Rail	9,833	9,833	6,103	6,103
Anthropogenic	Commercial Marine [4]	0	0	0	0
Anthropogenic	Agricultural Fire	96	96	96	96
Anthropogenic	Wildland Prescribed Fire	667	517	517	517
Natural	Wildfire	132	6,429	6,429	6,429
Natural	Biogenic [5]	48,405	48,405	48,405	48,405

1) 2028OTBa2 refers to the On the Books assumptions for US anthropogenic emissions in 2028. 2028OTBa2 fire emissions are the same as Represent
2) The Agricultural emissions sector includes only NH3 emissions from nonpoint livestock and fertilizer application.
3) The Fugitive Dust sector contains only PM10 and PM2.5 emissions from area-source anthropogenic dust sources.
4) Commercial Marine Shipping C1, C2, and C3 emissions within and offshore of the state.
5) Biogenic emissions are reported for CO, NOx, and VOC.

Table 10. Colorado Sulfur dioxide (SO2) emissions (tons/year) for 2014v2, Representative Baseline 2, 2028 On the Books (2028OTBa2), and 2028 Potential Additional Controls (2028PAC2) scenarios and 16 emissions sectors TSS Emissions Express Tool # 4.

State: **Colorado**

Pollutant: **Sulfur Dioxide** tons/year

State Emissions	Source Category	2014v2 Actual	Representative Baseline 2	2028 OTB a2 [1]	2028 PAC2
Anthropogenic	Electric Generating Units (EGU)	28,158	11,425	9,309	9,309
Anthropogenic	Oil and Gas - Point	583	514	478	478
Anthropogenic	Industrial and Non-EGU Point	3,335	3,343	3,349	3,349
Anthropogenic	Oil and Gas - Non-point	182	22	24	24
Anthropogenic	Residential Wood Combustion	48	48	48	48
Anthropogenic	Fugitive dust [3]	0	0	0	0
Anthropogenic	Agriculture [2]	0	0	0	0
Anthropogenic	Remaining Non-point	81	81	81	81
Anthropogenic	On-Road Mobile	458	458	180	180
Anthropogenic	Non-road Mobile	53	34	24	24
Anthropogenic	Rail	6	6	5	5
Anthropogenic	Commercial Marine [4]	0	0	0	0
Anthropogenic	Agricultural Fire	30	30	30	30
Anthropogenic	Wildland Prescribed Fire	401	519	519	519
Natural	Wildfire	66	6,684	6,684	6,684
Natural	Biogenic [5]	0	0	0	0

1) 2028OTBa2 refers to the On the Books assumptions for US anthropogenic emissions in 2028. 2028OTBa2 fire emissions are the same as Represent
2) The Agricultural emissions sector includes only NH3 emissions from nonpoint livestock and fertilizer application.
3) The Fugitive Dust sector contains only PM10 and PM2.5 emissions from area-source anthropogenic dust sources.
4) Commercial Marine Shipping C1, C2, and C3 emissions within and offshore of the state.
5) Biogenic emissions are reported for CO, NOx, and VOC.

Maps of total state or county emissions for 4 emissions scenarios and 7 pollutant emissions can be downloaded using [TSS Emissions Express Tools] #8 and 9.

Figure 4a. Total anthropogenic NOx emissions for the western continental U. S. states for the 2014v2 emissions scenario. [TSS Emissions Express Tool] # 8.

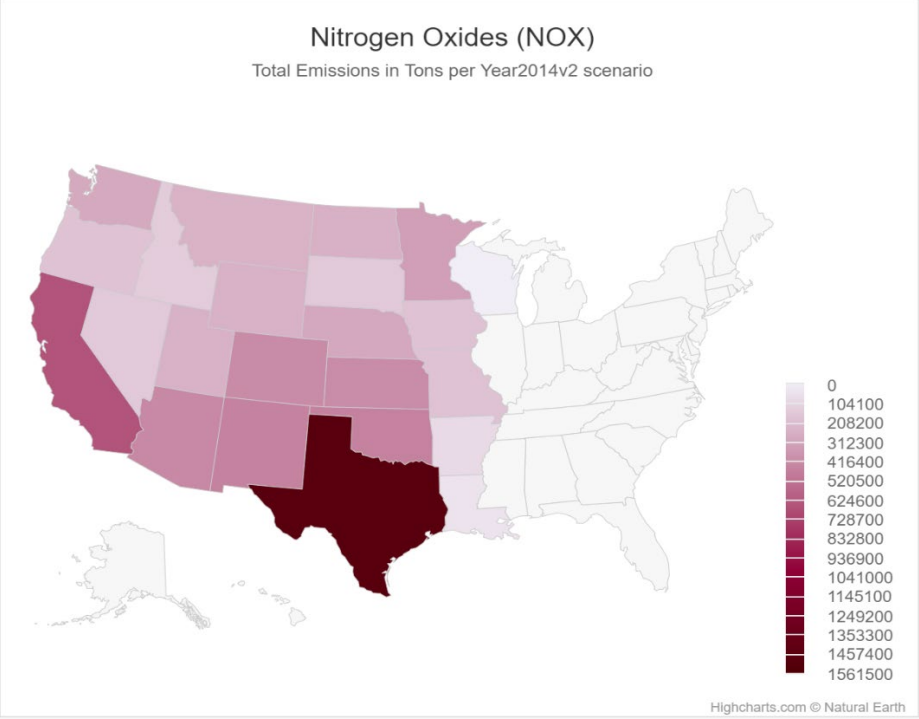
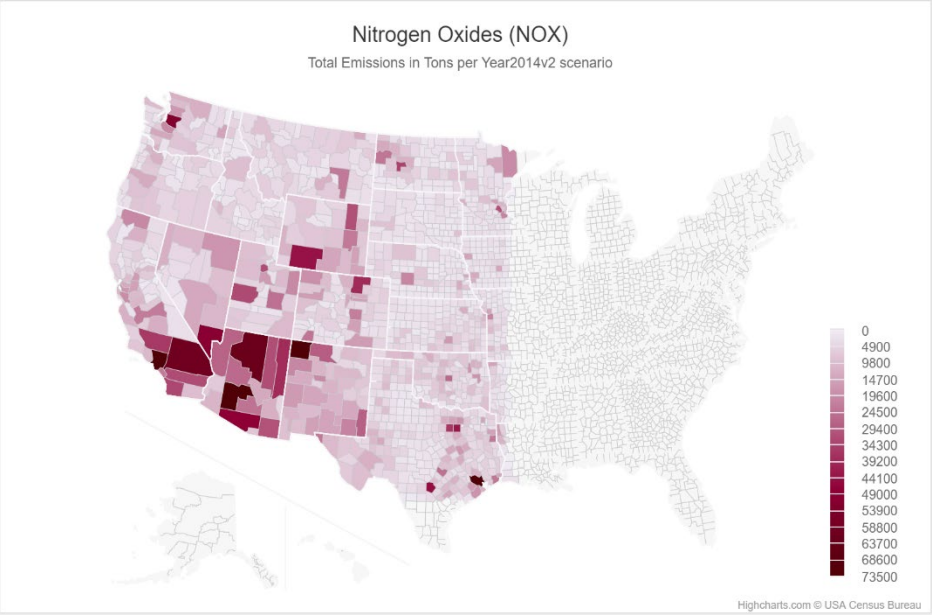
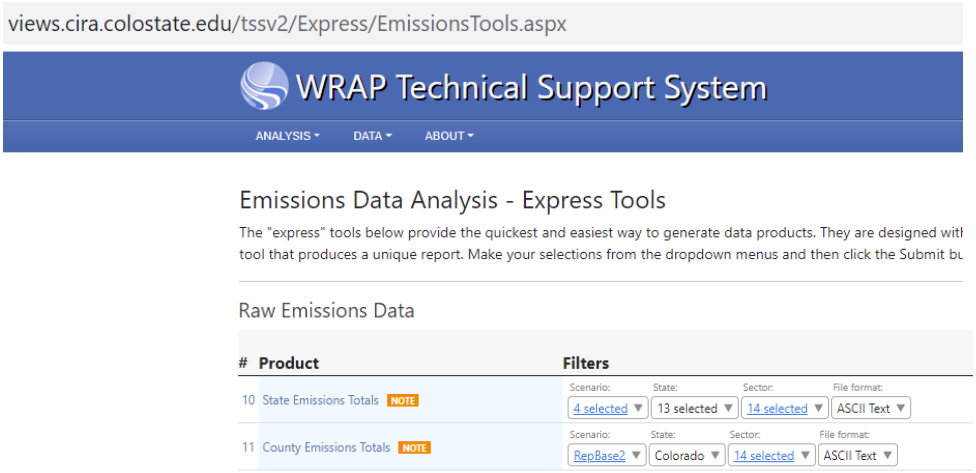


Figure 4b. Total anthropogenic NOx emissions for the western continental U. S. counties (for the 2014v2 emissions scenario. [TSS Emissions Express Tool] # 9.



State and county emissions datasets for 4 emissions scenarios and 16 anthropogenic plus 6 natural emission sectors can be downloaded through [TSS Emissions Express Tools](views.cira.colostate.edu/tssv2/Express/EmissionsTools.aspx) #10 and 11.



As of September 16, 2021, TSS Emissions Express Tools are still under development for:

- Table comparing by state of 2017 National Emissions Inventory (NEI) to 2014v2, RepBase2 and 2028OTBa2 emissions sectors.
    - These data are available for download as data tables displayed with TSS Emissions Express Tools 1-3.
- Comparison by state of 2002 Hindcast to RepBase2 and 2028OTBa2 emissions sectors.

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Section 1.0 Introduction

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U.S. Environmental Protection Agency (EPA) Technical Support Document for EPA's updated 2028 regional haze modeling (September 2019) https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling

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Western Regional Air Partnership (WRAP) Technical Steering Committee webpage. http://www.wrapair2.org/TSC.aspx

The Western Regional Air Partnership (WRAP) Technical Support System (TSS) https://views.cira.colostate.edu/tssv2/

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Section 3.0 Emissions Scenarios

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Western Regional Air Partnership (WRAP) Oil and Gas Workgroup Roadmap for updating oil and gas inventories
http://www.wrapair2.org/pdf/OGWG_Roadmap_FinalPhase1Report_Workplan_13Apr2018.pdf

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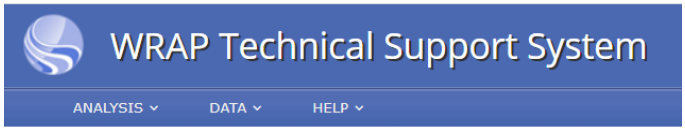
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Appendix B: WRAP Technical Support System for Regional Haze Planning: Modeling Methods, Results, and References







WRAP Technical Support System for Regional Haze Planning:

Modeling Methods, Results, and References

September 30, 2021 - Final

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1.0 Purpose:

The Western Regional Air Partnership and Western Air Quality Study (WRAP-WAQS) 2014 Regional Haze modeling platform is the latest of a series of regional modeling efforts supporting western U.S. air quality planning and management. The WRAP technical analyses follow the Environmental Protection Agency's (EPA) Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze (November 2018) and the Technical Support Document for EPA's updated 2028 regional haze modeling (September 2019). The analyses fulfill the objectives of the WRAP 2018-2019 Workplan as updated and approved by the WRAP Board on April 3, 2019 and have been collectively designed, implemented, and reviewed by the WRAP Technical Steering Committee and its workgroups and subcommittees.

The Western Regional Air Partnership (WRAP) Technical Support System (TSS) hosts the visibility monitoring, emissions, and air quality modeling analyses that support the 15 western states in developing regional haze state implementation plans (SIPs). This reference document describes the WRAP emissions and modeling analyses and illustrates how the TSS products can be applied and interpreted to support the 2028 visibility progress demonstrations for western U.S. Class I areas.

2.0 Background:

The Regional Haze Rule requires states to demonstrate progress every ten years toward the Clean Air Act goal of no manmade visibility impairment. EPA guidance for tracking visibility progress (December 2018) defines a visibility impairment tracking metric (measured in deciview) using observations from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring network sites that represent Class I areas. EPA defined in the Regional Haze Rule and guidance a Uniform Rate of Progress glidepath for the 20% most impaired days as the straight line from the 2000-2004 IMPROVE 5-year average baseline to EPA estimates of future natural visibility conditions, plotted at 2064. In the first regional haze planning period, 2000-2018, EPA guidance interpreted most impaired days as those days with highest total haze. States were required to demonstrate visibility progress by 2018 compared to the Uniform Rate of Progress glidepath for the haziest days and no degradation of visibility on the clearest days from the 2000-2004 IMPROVE 5-year average baseline. Visibility on the clearest days improved between 2000 and 2018 across the Class I areas in the western U.S. However, smoke from wildfire and wildland prescribed fire events and dust events on the haziest days made tracking the visibility benefits due to reducing U.S. anthropogenic emissions more difficult.

For the second regional haze implementation period, 2018-2028, states are required to demonstrate visibility progress by 2028 for the most impaired days and no visibility degradation for the clearest days. EPA guidance (December 2018) defined most impaired days as those days with the highest fractional contribution to aerosol light extinction from anthropogenic sources. EPA statistical methods use IMPROVE measurements of carbon and crustal materials to separate contributions from episodic extreme natural events (e.g., wildfire or dust) from routine natural and anthropogenic contributions. Ammonium sulfate and ammonium nitrate are assigned primarily to anthropogenic emissions with smaller contributions from routine natural sources. This statistical approach does not separate contributions due to U.S. anthropogenic emissions from those of international anthropogenic emissions. Since states do not have authority to reduce international emissions, WRAP conducted source apportionment modeling analyses to evaluate U.S. anthropogenic contributions to haze and progress in reducing U.S. anthropogenic contributions to haze over time.

Table 1 summarizes the emissions and modeling scenarios, source apportionment runs, and alternative visibility progress analyses that were performed to support state regional haze planning.

Table 1. WESTAR-WRAP Emissions and Modeling Scenarios – update of January 18, 2021
Intermountain West Data Warehouse (IWDW) and Technical Support System (TSS) displays

Scenario Name	**Model Performance Evaluation** (2014v2 actual emissions / BCs and meteorology)	**Planning – Baseline** (mix of emissions inputs 2014-18 with 2014 meteorology)	**Planning – 2028 Projections** (2014 meteorology)	**Alternative Methods: 2028 Projections, Glidepath Endpoints, and Rate of Progress**	**Alternate Outcome Scenarios** (2014meteorology)
IWDW	Display emissions, model results, and site-level MPE results)	Display emissions and model results	Display emissions and model results		
TSS	Display emissions and model results	Display emissions and model results	Calculate and Display 2028 RPGs Display emissions and model results	Display alternative 2028 projections, glidepath endpoints, rate of progress	Calculate and Display 2028 RPGs. Display emissions and model results
Purpose	**Compare 2014v2 to RepBase2**	**Compare to RepBase2 to 2014v2, 2028OTBa2, 2028PAC2**	**Compare 2028OTBa2 to Repbase2, 2028PAC2, 2028FFS1, 2028FFS2**	**Focus on contributions of US anthropogenic emissions**	**Evaluate state source contributions and future fire scenarios**
CAMx Modeling Scenarios	**2014v2**	**RepBase2** Current Baseline (w/ RepFire). High-level CAMx PSAT source apportionment*	**2028OTBa2** (w/ RepFire) ** High-level PSAT source apportionment	**3 projection methods:** EPA default MID EPA MID w/o fires Modeled MID	**2028OTBa2 w/ SOxNOx PSAT** low-level (state by source sector contributions)
			2028PAC2 PotentialAddtlControls	Alternative 2064 glidepath endpoints	**2028FF1** Future Fire Sensitivity 1: Wildfire ****
			2028Adopted AddtlControls ***	U.S. Anthropogenic Modeled Rate of Visibility Progress ******	**2028FF2** Future Fire Sensitivity 2: WildlandRxFire *****

* 2014 International Anthro contribution adjustment option available from this modeling scenario (by difference)
** RepBase fires applied to 2028OTBa2
*** controls adopted by states in SIPs, this scenario is likely not possible until 2021 (*unfunded at present, not in Workplan*)
**** fire not paired in space or time with 2014 or RepFire activity, these sensitivity scenarios could give potential future wildfire contribution relative to 2028OTBa2
***** fire *is* paired in space *and* time with RepFire activity; this sensitivity scenario gives potential future Wildland Prescribed fire contribution relative to 2028OTBa2
******Dynamic Evaluation compare US anthropogenic contributions for 2002 Hindcast, RepBase2, and 2028OTBa2 to demonstrate alternative rate of visibility improvement

3.0 Emissions Scenarios:

The WRAP 2014v2 inventory was based on the 2014v2 National Emissions Inventory (NEI) plus updates provided by western states through WRAP Regional Haze workgroup's Emissions and Modeling Protocol subcommittee.

Table 2 defines the emissions data sources used for the WRAP 2014v2, Representative Baseline (RepBase2), and 2028 On the Books (2028OTBa2) emissions scenarios. Sector-specific data sources and assumptions are discussed in the companion TSS Emissions References document (September 2021). Future fire emissions sensitivities and 2002 hindcast emissions are also detailed in the TSS Emissions References document.

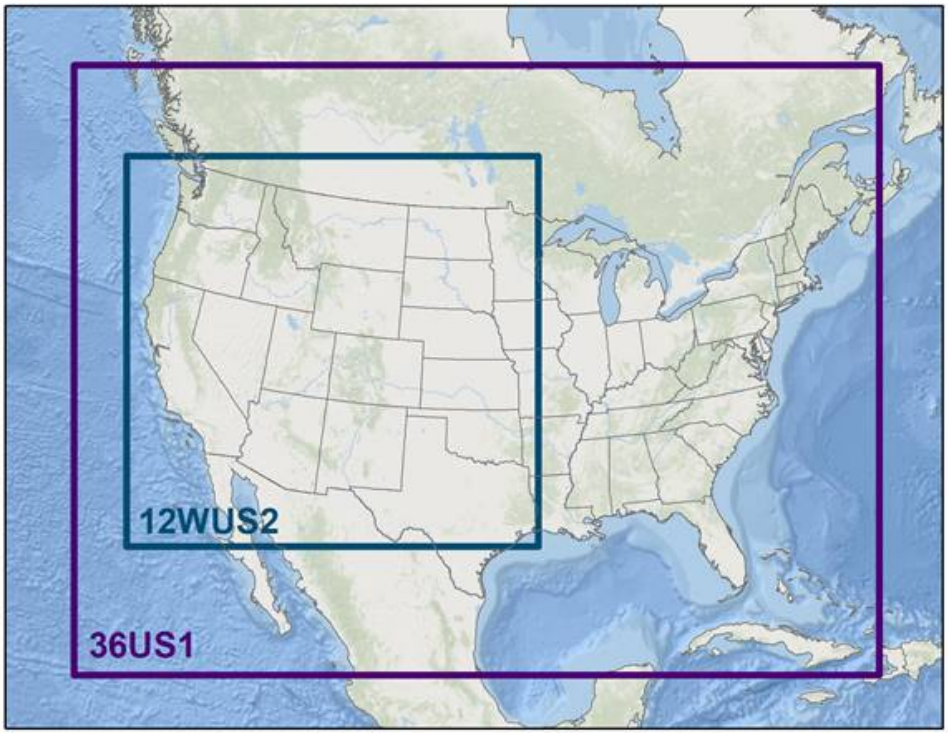
Table 2. Data sources for WRAP emissions sectors for the 12-km 12WUS2 and 36-km US domains for the 2014v2, Representative Baseline (RepBase2) and 2028 On the Books (2028OTBa2) scenarios.

Source Sector	**2014v2**	**RepBase2**	**2028OTBa2**
California All Sectors 12WUS2	CARB-2014v2	CARB-2014v2	CARB-2028
WRAP Fossil EGU w/ CEM	WRAP-2014v2	WRAP-RB-EGU [1]	WRAP-2028-EGU [1]
WRAP Fossil EGU w/o CEM	EPA-2014v2	WRAP-RB-EGU [1]	WRAP-2028-EGU [1]
WRAP Non-Fossil EGU	EPA-2014v2	EPA-2016v1	EPA-2028v1
Non-WRAP EGU	EPA-2014v2	EPA-2016v1	EPA-2028v1
O&G WRAP O&G States	WRAP-2014v2	WRAP-RB-O&G [2]	WRAP-2028-O&G [2]
O&G WRAP Other States	EPA-2014v2	EPA-2016v1	EPA-2016v1 [3]
O&G non-WRAP States	EPA-2014v2	EPA-2016v1	EPA-2016v1 [3]
WRAP Non-EGU Point	WRAP-2014v2	WRAP-2014v2 [4]	WRAP-2014v2 [4]
Non-WRAP non-EGU Point	EPA-2014v2	EPA-2016v1	EPA-2016v1
On-Road Mobile 12WUS2	WRAP-2014v2	WRAP-2014v2	WRAP-2028-Mobile [5]
On-Road Mobile 36US	EPA-2014v2	EPA-2016v1	EPA-2028v1
Non-Road 12WUS2	EPA-2014v2	EPA-2016v1	WRAP-2028-Mobile [5]
Non-Road non-WRAP 36US	EPA-2014v2	EPA-2016v1 [6]	EPA-2028v1 [6]
Other (Non-Point) 12WUS2	EPA-2014v2	EPA-2014v2 [7]	EPA-2014v2 [7]
Other (Non-Point) 36US	EPA-2014v2	EPA-2016v1	EPA-2016v1
Can/Mex/Offshore 12WUS2	EPA-2014v2	EPA-2016v1	EPA-2016v1
Fires (WF, Rx, Ag)	WRAP-2014-Fires	WRAP-RB-Fires [8]	WRAP-RB-Fires [8]
Natural (Bio, etc.)	WRAP-2014v2	WRAP-2014v2	WRAP-2014v2
Boundary Conditions (BCs)	WRAP-2014-GEOS	WRAP-2014-GEOS	WRAP-2014-GEOS

4.0 Model Development:

The WRAP-WAQS 2014 modeling platform was developed and performed by Ramboll, Inc., under contract to WESTAR-WRAP. The 2014 modeling platform used the Weather Research and Forecasting (WRF) meteorological model, the Sparse Matrix Operator Kernel Emissions (SMOKE) model and the Comprehensive Air Quality Model with Extensions (CAMx) to project air quality for the 2014 base year. The Goddard Earth Observing System global chemical model (GEOS-Chem) provided global boundary conditions for the regional CAMx model for the 2014 base year. The CAMx 2014v2 final model configuration is defined in Table 1 of the WRAP-WAQS 2014 modeling platform webpage. CAMx version 7beta 6 was used for the 2014v2 model performance run, while CAMx version 7.0 was used for the subsequent model scenarios. **Figure 1** below illustrates the CAMx 36-km modeling domain covering the Continental United States and the 12-km modeling domain covering the western states.

Figure 1. 36-km continental U.S. (36US1) and 12-km western U.S. (12US2) modeling domains used in the WRAP-WAQS 2014 modeling platform.



In addition to the 2014v2 model year, model runs were made using 2014 meteorology and with Representative Baseline (2014-2018, RepBase2), 2028 On the Books (2028OTBa2), 2028 Potential Additional Controls (2028PAC2), 2002 Hindcast, and Future Fire Sensitivities emission scenarios. Details are provided in model run specification sheets:

- Representative Baseline (RepBase2) and 2028 On the Books (2028OTBa2) CAMx simulations
- Dynamic Evaluation – 2002 Simulations
- Future Fire Sensitivity Simulations

5.0 WRAP-WAQS 2014v2 model performance

The WRAP-WAQS 2014v2 modeling platform webpage includes statistical model performance measures compared to EPA goals and criteria, spatial data plots and timeseries plots for the aerosol species listed below. For aerosol species concentrations, CAMx 2014v2 model outputs are compared to 2014 observations from the IMPROVE, Chemical Speciation Network (CSN) and Clean Air Status and Trends (CASTNET) monitoring network.

- Ozone model performance is reported on the Intermountain West Data Warehouse.

CAMx 2014v2 performance was evaluated using the EPA Atmospheric Model Evaluation tool (AMET) to compare model outputs to 2014 ambient air quality measurements (in μg/m3) for:

- Particulate matter less than 2.5 micrometers (PM2.5)
- Nitrate (NO3)
- Sulfate (SO4)
- Organic mass from carbon (OMC)
- Elemental carbon (EC)
- Fine soil (Soil)
- Coarse mass (particulate matter between 2.5 and 10 micrometers).
- Seasalt: performance is tracked separately for Sodium and Chloride

For example, **Figures 2a to 2d** are spatial plots of the Normalized Mean bias statistic for the winter months January - March and Summer months July – September, for Nitrate and Sulfate, respectively. IMPROVE sites are illustrated as circles, CSN sites as triangles, and CASTNET sites as squares. In Winter, Nitrate is overpredicted in the Pacific Northwest and CA and underpredicted in the northern plains. Performance is generally mixed in the Rocky Mountains and Southwestern interior. In Summer, Nitrate is overpredicted in the Pacific Northwest and under predicted in CA. Sulfate is generally overpredicted in the Pacific Northwest in winter and underpredicted in the Southwest in summer.

Figure 2a. Normalized mean bias for 2014v2 modeled Nitrate compared to the IMPROVE, CSN, and CASTNET monitoring networks for Winter (Jan – Mar). (2014v2 MPE summary)

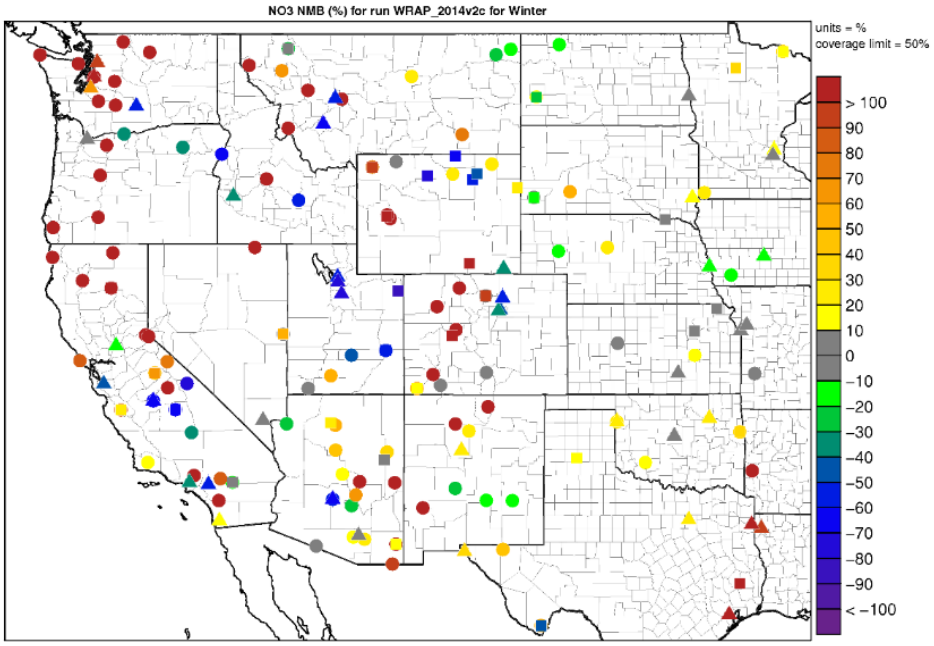


Figure 2b. Normalized mean bias for 2014v2 modeled Nitrate compared to the IMPROVE, CSN, and CASTNET monitoring networks for Summer (Jul – Sep). (2014v2 MPE summary)

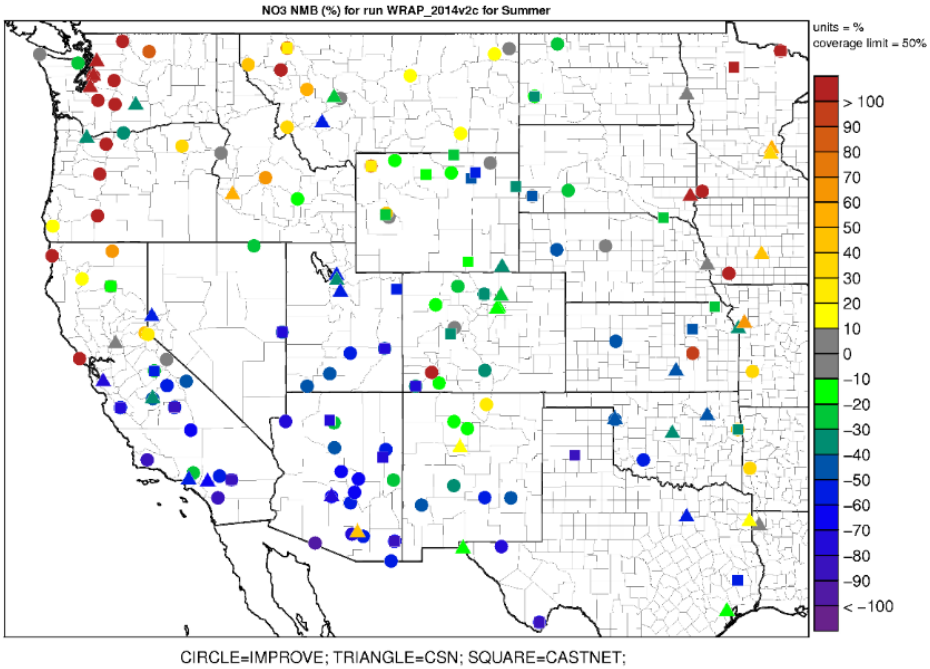


Figure 2c. Normalized mean bias for 2014v2 modeled Sulfate compared to the IMPROVE, CSN, and CASTNET monitoring networks for Winter (Jan – Mar). (2014v2 MPE summary)

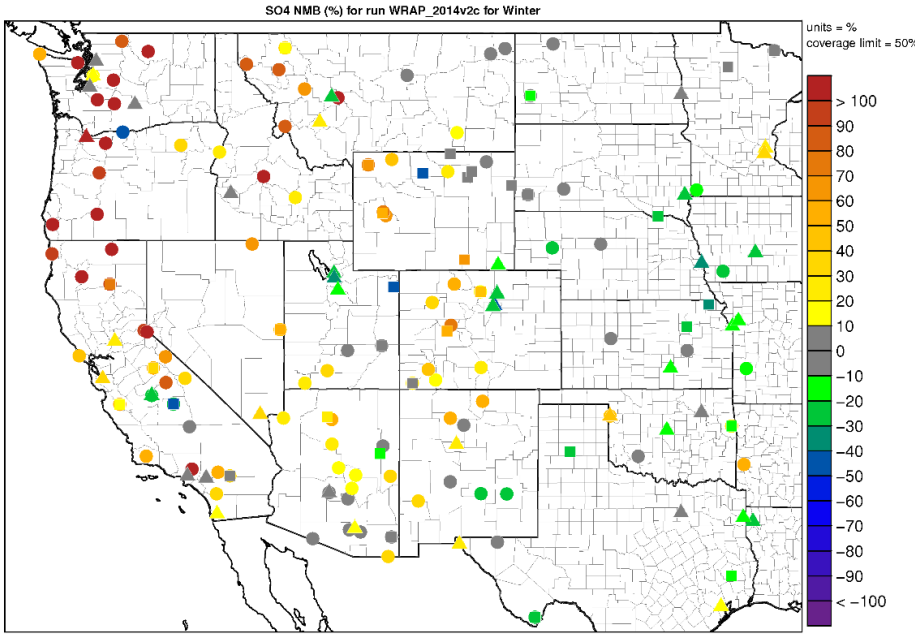
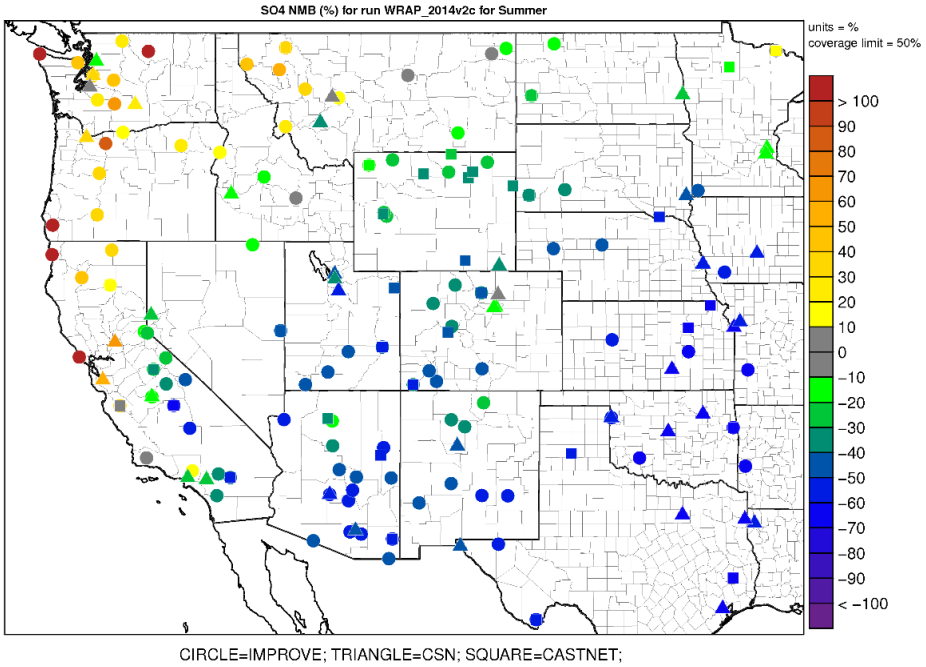


Figure 2d. Normalized mean bias for 2014v2 modeled Sulfate compared to the IMPROVE, CSN, and CASTNET monitoring networks for Summer (Jul – Sep). (2014v2 MPE summary)



CAMx 12-km gridded annual anthropogenic nitrogen oxide and anthropogenic sulfur dioxide emissions (tons per year) for 2028OTBa emissions (from the WRAP 2028 Weighted Emissions Potential analyses) are mapped in **Figures 3a and 3b**.

Figure 3a. 2028 On the Books CAMx gridded 12-km annual anthropogenic nitrogen oxide emissions (tons per year) (Weighted Emissions Potential)

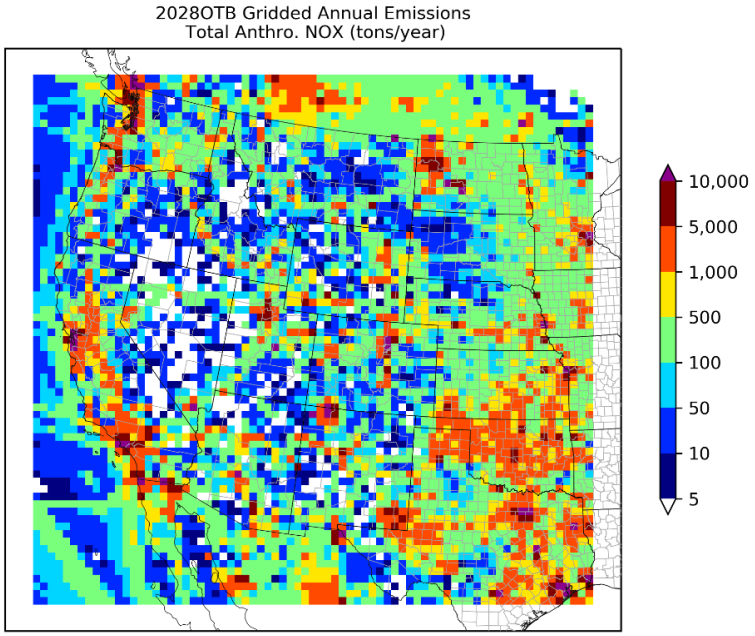
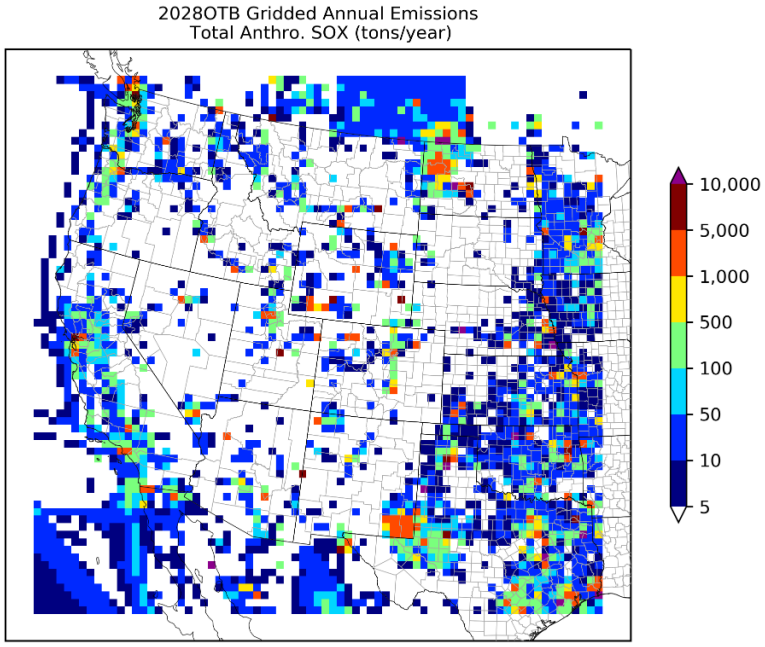


Figure 3b. 2028 On the Books CAMx gridded 12-km annual anthropogenic sulfur oxides emissions (tons per year) (Weighted Emissions Potential)



6.0 Model Comparisons to Observations

Yellowstone National Park, in a fire-dominated ecosystem in the northern Rocky Mountains, and Mesa Verde National Park, in a drier southwestern ecosystem, are used as example Class I areas to interpret WESTAR-WRAP 2014v2 model performance, source contributions to haze, and projected visibility progress by 2028.

Comparisons of 2014 IMPROVE observations to the 2014v2, RepBase2, and 2028OTBa2 model scenarios are illustrated in **Figures 7a through 7d** (TSS Modeling Express Chart #1) for IMPROVE monitors in Yellowstone (YELL2) and Mesa Verde (MEVE1) National Parks, respectively. The charts display speciated aerosol light extinction for the averages of the most impaired days or clearest days. These are absolute model results; the model outputs are not adjusted to IMPROVE data. Comparison of 2014 IMPROVE observations to 2014v2 model results illustrates the accuracy of the model performance on the selected days. Comparison of the 2014v2, RepBase2, and 2028OTBa2 model scenario results demonstrates the aerosol responses to changes in emissions across these scenarios. Natural, fire, and international emissions are held constant at RepBase2 levels in 2028OTBa2, so the only differences between the two scenarios are due to changes in U.S. anthropogenic emissions.

Interpretation: Comparing 2014 IMPROVE observations to 2014v2 model results on most impaired days (**Figures 7a and 7b**) at both YELL2 and MEVE1, ammonium sulfate, elemental carbon, and coarse mass are under predicted, while ammonium nitrate and organic carbon are over predicted. At both YELL2 and MEVE1 organic carbon is slightly higher in RepBase2 than 2014v2; this reflects changes for wildfire emissions in the RepBase2 scenario. At both YELL2 and MEVE1 ammonium nitrate shows small reductions between the RepBase2 and 2028OTBa2 scenarios, all other aerosol species show little change.

On the clearest days at both YELL2 and MEVE1 (**Figure 7c and 7d**) all aerosol species are overestimated, likely because aerosol concentrations are very low and small differences in light extinction are reflected as large percentage differences.

TSS Modeling Express charts for the clearest days are formatted the same as for the most impaired days and will not be displayed in this document forward.

Figure 4a. Model Scenarios Compared to 2014 IMPROVE Observations for Aerosol Light Extinction (Mm^{-1}) on the most impaired days at the Yellowstone National Park (YELL2) IMPROVE monitor. TSS Modeling Express Chart #1

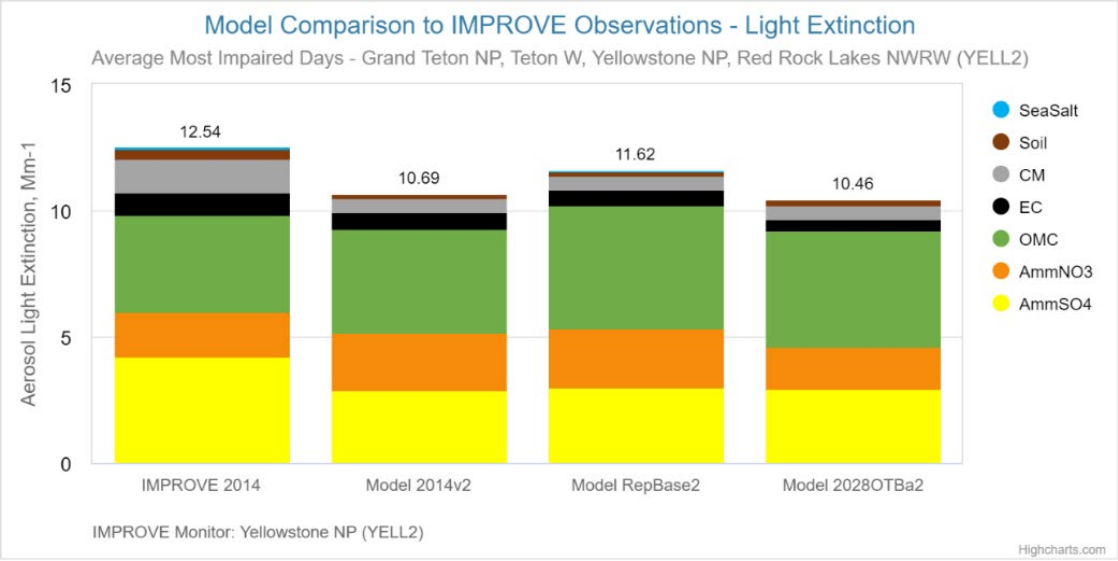


Figure 4b. Model Scenarios Compared to 2014 IMPROVE Observations for Aerosol Light Extinction (Mm^{-1}) on the most impaired days at the Mesa Verde National Park (MEVE1) IMPROVE monitor. TSS Modeling Express Chart #1

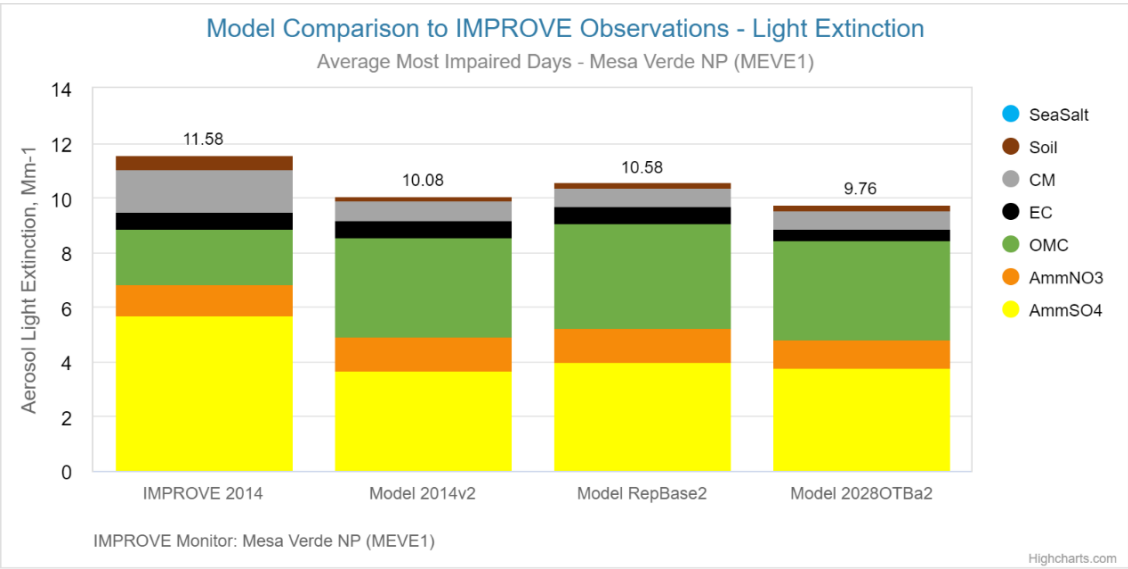


Figure 4c. Model Scenarios Compared to 2014 IMPROVE Observations for Aerosol Light Extinction (Mm^{-1}) on the clearest days at the Yellowstone National Park (YELL2) IMPROVE monitor. TSS Modeling Express Chart #1

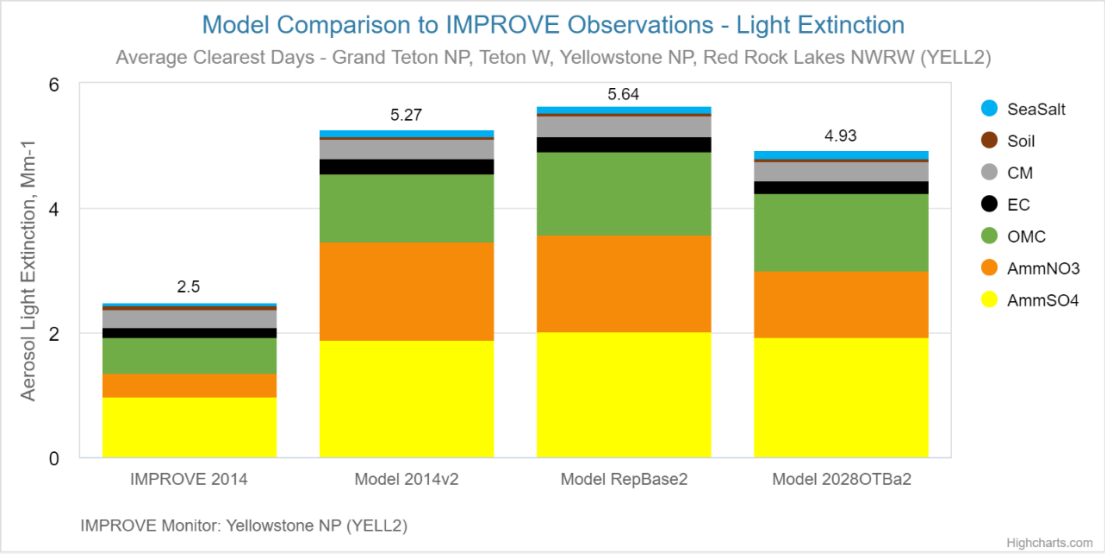
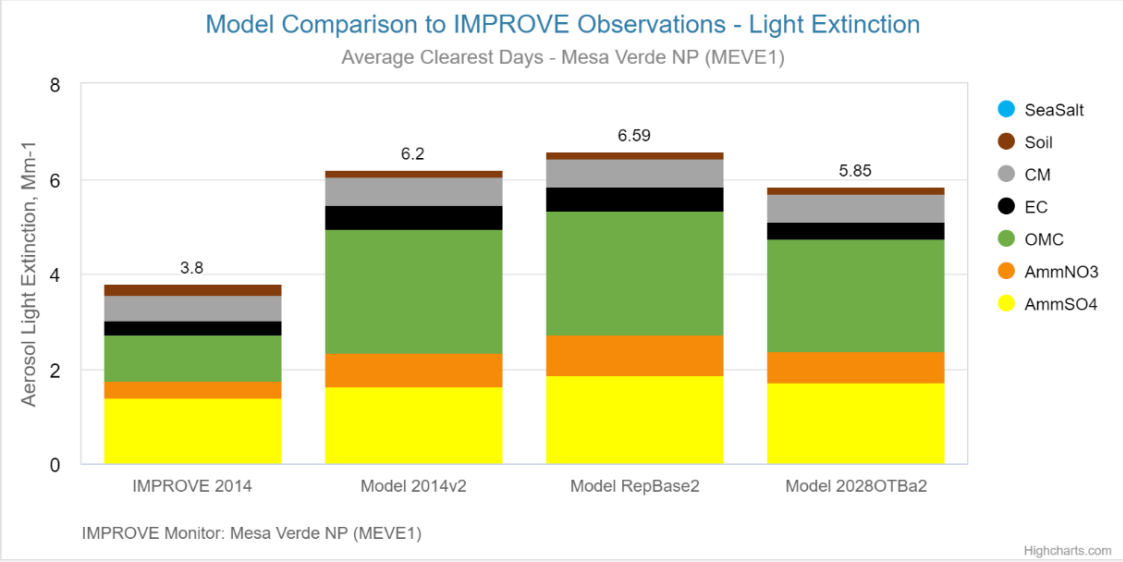


Figure 4d. Model Scenarios Compared to 2014 IMPROVE Observations for Aerosol Light Extinction (Mm^{-1}) on the clearest days at the Mesa Verde National Park (MEVE1) IMPROVE monitor. TSS Modeling Express Chart #1



Figures 5a and 5b display TSS Modeling Express Chart #2 for daily 2014 IMPROVE most impaired days at Yellowstone (YELL2) and Mesa Verde (MEVE1) National Parks, respectively, compared to the 2014v2, RepBase2, and 2028OTBa2 model scenarios.

Interpretation: Overall, comparing 2014 IMPROVE data to the 2014v2 modeled aerosol light extinction, CAMx showed credible skill for most impaired days at YELL2 and MEVE1. Maximum IMPROVE daily aerosol extinction on most impaired days is 24 Mm^{-1} at YELL2 and 20 Mm^{-1} at MEVE1. Daily ammonium nitrate (AmmNO3) is well represented on most impaired days at these two sites. On a few most impaired days at both YELL2 and MEVE1, 2014v2 modeled ammonium sulfate (AmmSO4) is more than 50% lower than IMPROVE observations. Under estimates of coarse mass are likely due to poor model skill in representing windblown dust. At both sites, organic carbon (OMC) is a large fraction of total aerosol extinction on several 2014 IMPROVE most impaired days. OMC is somewhat over predicted on several days. Differences in OMC on the most impaired days between the 2014v2 and RepBase2 scenarios are likely due to differences in wildfire activity assumptions for RepBase2 (covering the period the 2014 to 2018) compared to the single year 2014v2. Differences in total aerosol extinction between RepBase2 and 2028OTBa2 are small on all most impaired days, indicating little visibility progress.

Figure 5a. Model Scenarios Compared to 2014 IMPROVE Observations for Aerosol Light Extinction (Mm^{-1}) on most impaired days at the Yellowstone National Park (YELL1) IMPROVE monitor. TSS Modeling Express Chart #2

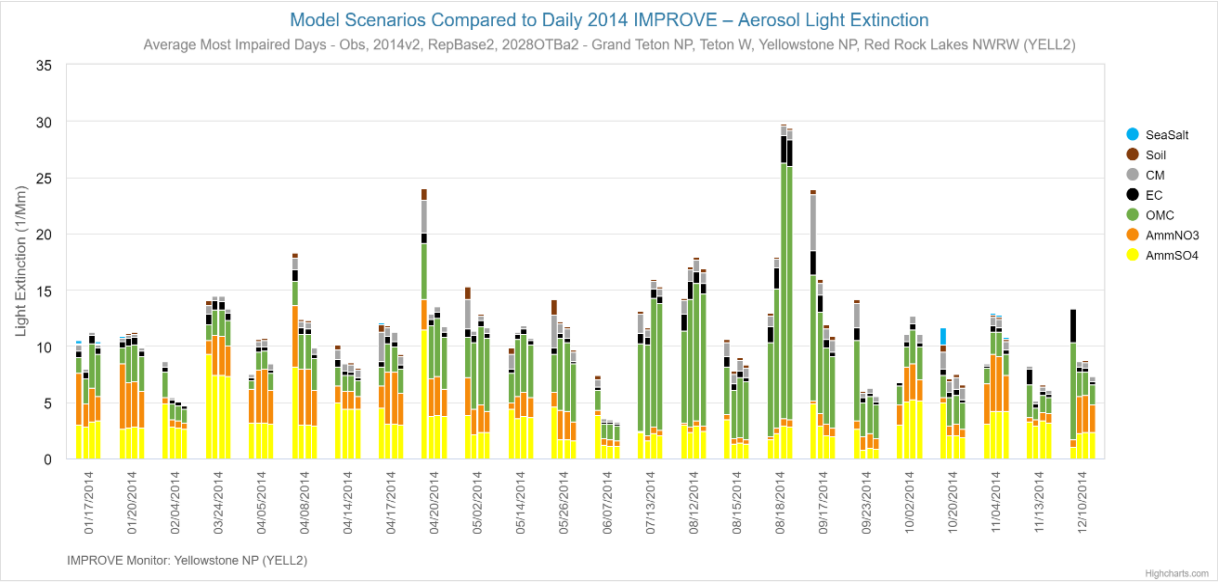
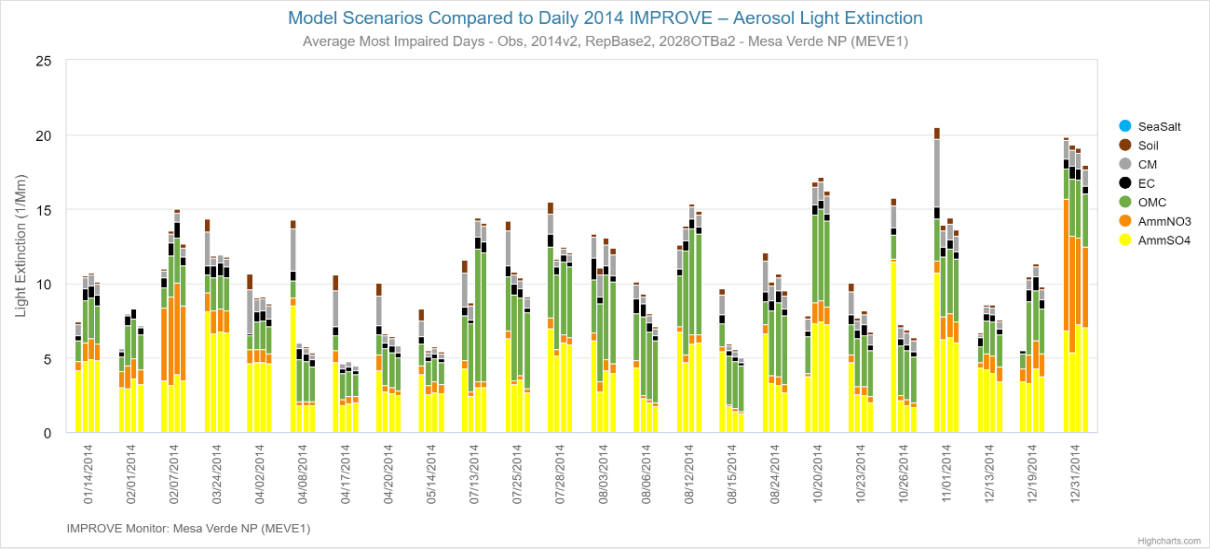


Figure 5b. Model Scenarios Compared to 2014 IMPROVE Observations for Aerosol Light Extinction (Mm^{-1}) on most impaired days at the Mesa Verde National Park (MEVE1) IMPROVE monitor. TSS Modeling Express Chart #2



7.0 2028 Visibility Projections

2028 visibility projections for the most impaired or clearest days are calculated following EPA guidance for ozone, PM2.5 and regional haze modeling (November 2018) using the EPA default projection method and using two WRAP alternative projection methods that are intended to reduce aerosol contributions from sources other than U.S. anthropogenic emissions on the most impaired days.

The EPA recommended projection procedures are used for all three WRAP projection methods (see WRAP Procedures for Making Visibility Projections and Adjusting Glidepaths, March 2021 final draft.) EPA's Software for the Model Attainment Test (SMAT) was used to perform the projection calculations. CAMx model results are used in a relative sense, meaning that the aerosol concentrations are scaled to the IMPROVE monitoring data for the 2014-2018 period. The fractional differences between the 2028OTBa2 and the RepBase2 modeled aerosol concentrations are used to define scaling factors, also called relative response factors (RRFs), that are calculated for each aerosol species on each 2014 IMPROVE most impaired day (or clearest day) and then averaged for all most impaired days (or clearest days). These average relative response factors are multiplied by the daily aerosol concentration on each most impaired day or clearest day for the IMPROVE 2014-2018 5-year period to define daily projected aerosol concentrations, as indicated by the equations below.

$$\text{Relative Response Factor, } RRF_{SO4} = \sum 2028OTBa2_{SO4} / \sum RepBase2_{SO4}$$

$$Projected_SO4_{2028OTBa2} = IMPROVE_SO4_{2014\text{-}2018} \times RRF_{SO4}$$

The daily projected 2028 aerosol concentrations for each of the 2014-2018 IMPROVE most impaired days (or clearest days) are converted to light extinction and then converted to deciview. The daily deciview values are averaged for each year and the annual averages are averaged for the 5-year period to define the 2028 visibility projections. The three WRAP projection methods:

- The **EPA default projection method** follows EPA guidance without deviation.
- The **EPA without fire projection method** uses the same 2014 IMPROVE most impaired days as the EPA default projection method. RepBase2 and 2028OTBa2 modeled source apportionment results are used to identify and remove modeled aerosol contributions from U.S. wildfire, U.S. wildland prescribed fire, and Non-U.S. (Canada and Mexico) fire on these days. After modeled fire contributions have been removed from the daily aerosol values, the EPA default projection procedures are used to calculate the relative response factors and 2028 visibility projections.
- The **Modeled MID projection method** selects the modeled RepBase2 days with the highest fraction of modeled U.S. anthropogenic contributions as the modeled most impaired days for both the RepBase2 and 2028OTBa2 scenarios. RepBase2 and 2028OTBa2 modeled source apportionment results are used to remove the fire contributions from the modeled most impaired days before calculating relative response factors and 2028 visibility projections.

In TSS Modeling Express Chart #3 users can choose to illustrate, for one, two, or three projection methods, for either the most impaired days or clearest days, the visibility projections for 2028 On the Books (2028OTBa2) or 2028 Potential Additional Controls (2028PAC2) in aerosol light extinction. These aerosol contributions are the basis for the 2028 visibility projections in deciview that define the regional haze tracking metric and are displayed in TSS TSS Modeling Express Chart #4 (see Section 8.0). Changes in aerosol species extinction across the 2028 projection scenarios and methods illustrate which aerosol species are responsible for the projected changes in the regional haze visibility tracking metric in deciviews.

Figures 6a and 6b illustrate the IMPROVE 2014-2018 aerosol contributions and the 2028OTBa2 visibility projections in aerosol light extinction using the 3 WRAP projection methods for Yellowstone and Mesa Verde National Parks, respectively.

Interpretation: For YELL2, AmmNO3, OMC, and EC are projected to decrease between the 2014-2018 IMPROVE observations and modeled 2028OTBa2 following the EPA default projection methods. The EPA without fire method has slight decreases in OMC and EC compared to the EPA default method, while the Modeled MID method, which selects different days as most impaired, has slight decreases in OMC, EC, and AmmSO4 (0.3 Mm^{-1}). At MEVE1, AmmNO3 and AmmSO4 are reduced slightly between 2014-2018 IMPROVE observations and

2028OTBa2 projections using EPA default methods. The EPA without fire and Modeled MID methods display slight changes to OMC and EC compared to the EPA default method. As will be illustrated under Section 10.0 Regional Source Apportionment, biogenic and anthropogenic sources of carbon are significant and unchanged fractions of OMC and EC at these two sites. Thus, for these two sites, removing fire contributions from most impaired days only changes a fraction of the total carbon and the EPA without fire projection method has only small changes in the 2028 visibility projection.

Nonetheless, WRAP recommended that EPA without fire projection method be the default 2028 visibility projection displayed because this method removes the contributions of fire on the most impaired days and most closely focuses on anthropogenic contributions to haze.

Figure 6a. 2028 Visibility Projections on most impaired days in Aerosol Light Extinction (Mm^{-1}) compared to 2014-2018 IMPROVE observations for Yellowstone National Park (YELL2). TSS Modeling Express Chart #3

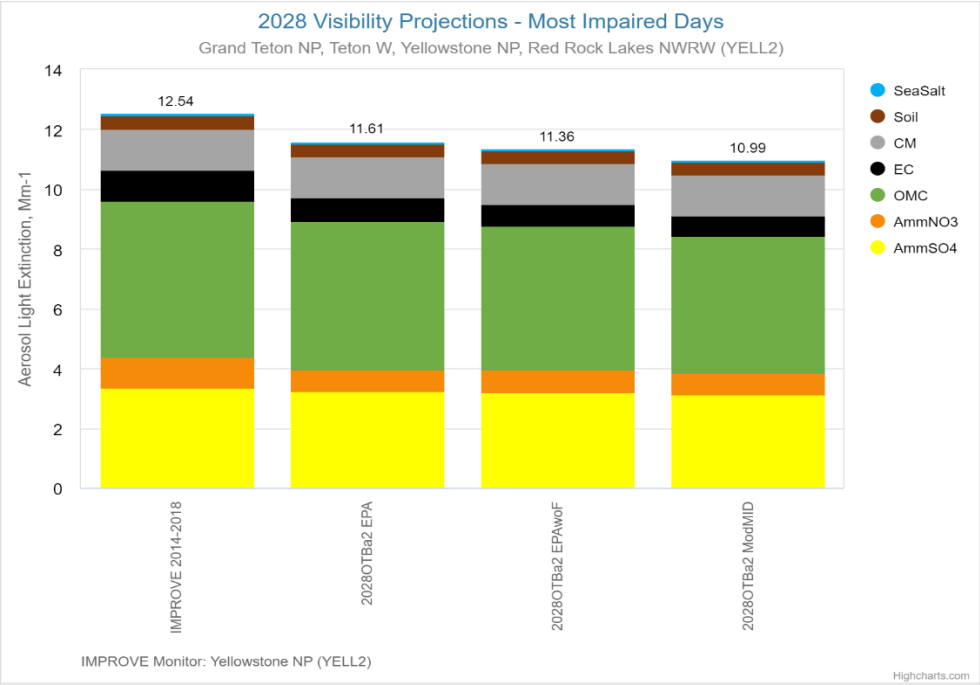
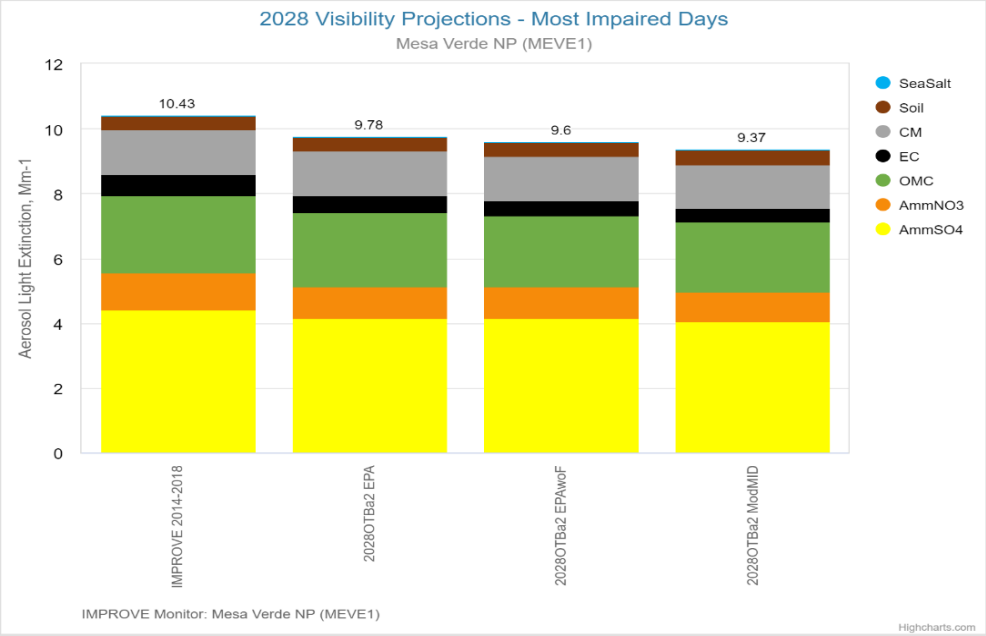


Figure 6b. 2028 Visibility Projections on most impaired days in Aerosol Light Extinction (Mm^{-1}) compared to 2014-2018 IMPROVE observations for Mesa Verde National Park (YELL2). TSS Modeling Express Chart #3



8.0 Visibility Projections compared to the Uniform Rate of Progress Glidepath

TSS Modeling Express Chart #4 displays 2028 visibility projections in deciview compared IMPROVE measurements for the period 2000-2018 and to the Uniform Rate of Progress (URP) glidepath as defined by EPA guidance (Dec 2018). The 2028 visibility projections in deciview are calculated from aerosol concentrations and extinction as described in Section 7. Users can also select to display chart data by aerosol light extinction for individual species or Total Light Extinction.

The URP glidepath is constructed (in deciviews) for the 20% most impaired days (MID) or clearest days using observations from the IMPROVE monitoring site representing a Class I area. The URP glidepath starts with the IMPROVE most impaired days for the 2000-2004 5-year baseline and draws a straight line to estimated natural conditions displayed for the year 2064. For clearest days, the goal is no degradation of visibility from the 2000-2004 5-year baseline, therefore the glidepath for clearest days is a straight line from the 2000-2004 baseline to 2064. In the second regional haze planning period, 2064 natural visibility condition estimates use the 15-year average of natural conditions on IMPROVE most impaired days in each year 2000-2014. IMPROVE annual average values are presented in this chart as points. IMPROVE 5-year average values are presented as solid lines covering the periods 2000-2004 and 2014-2018.

The 2028OTBa2 and 2028PAC2 visibility projections were processed using EPA's Software for the Model Attainment Test (SMAT) for the three WRAP projection methods described in Section 7 (see also WRAP Procedures for Making Visibility Projections and Adjusting Glidepaths, March 2021 final draft):

- EPA default projection method
- EPA without fire projection method
- Modeled MID projection method

2028 On the Books (2028OTBa2) and 2028 Potential Additional Controls (2028PAC2) visibility projections in deciview are illustrated as points that can be compared to the Uniform Rate of Progress glidepath. A state can select among the 2028 projection methods to define a 2028 Reasonable Progress Goal (RPG) for a Class I area for Regional Haze planning purposes.

The 2028 visibility projection is compared to the URP Glidepath at 2028 to determine whether visibility at the Class I areas is projected to be on, above, or below the URP Glidepath. Comparison of 2028 projections to the URP Glidepath defines how well the modeled trend in visibility tracks the straight-line uniform rate of progress to 2064. EPA guidance (August 2019) clarifies that the URP Glidepath is not a bright line test for reasonable visibility progress by 2028 and describes additional considerations for defining reasonable progress. Uncertainties in the glidepath assumptions are discussed in the U.S. Anthropogenic Emissions Rate of Progress (September 2021) document.

Figures 7a and 7b display TSS Modeling Express Chart #4 results for the 2028OTBa2 scenario for Yellowstone and Mesa Verde National Parks, respectively. Users could choose to also display results for the 2028PAC2 control scenario. Regional source apportionment data discussed in Section 10 will assist interpretation of 2028 visibility projections displayed in Chart #4.

Interpretation: For YELL2 (**Figure 7a**), the IMPROVE annual average deciview for the most impaired days varies widely between 2000 to 2018 and the 2000-2018 monitoring trend line (blue line) is above the URP Glidepath (red line). The IMPROVE 2014-2018 5-year average deciview for the most impaired days intersects the URP glidepath. The 2028OTBa2 visibility projections for all 3 WRAP methods are above the URP glidepath, although the EPA without fire and Modeled MID projection methods yield slightly lower 2028 projections than the EPA default projection. The IMPROVE annual average deciview for the clearest days show steady improvement between 2000 and 2018 and the 2028OTBa2 projection indicates further improvement on the clearest days.

At MEVE1 (**Figure 7b**) the IMPROVE annual average deciview for the most impaired days shows a consistent reduction between 2000 and 2018. The IMPROVE 2000-2018 monitoring trendline and the IMPROVE 2014-2018 5-year average deciview for the most impaired days are well below the URP glidepath. All 3 projection methods for 2028OTBa2 are also well below the URP

glidepath. The clearest days at MEVE1 also show continuous improvement and the 2028OTBa2 projections are below the 2014-2018 5-year average deciview.

Figure 7a. 2028 Visibility Projections for clearest days and most impaired days, compared to the Uniform Rate of Progress Glidepath at the Yellowstone National Park (YELL2) IMPROVE monitor. TSS Modeling Express Chart #4



Figure 7b. 2028 Visibility Projections for clearest days and most impaired days, compared to the Uniform Rate of Progress Glidepath at the Mesa Verde National Park (MEVE1) IMPROVE monitor. TSS Modeling Express Chart #4



In general, western Class I areas near urban areas or major point sources demonstrate visibility improvement in the IMPROVE monitoring data between 2000 to 2018 and the 2028 visibility projections are below the URP glidepath. Ammonium nitrate and ammonium sulfate are major contributors on most impaired days at many of these sites, including Mesa Verde NP (see **Figure 6b**). Class I areas near oil and gas development do not display as much visibility improvement by 2028OTBa2 as more remote sites. Class I areas where carbon is a significant fraction of aerosol contributions on most impaired days, including Yellowstone NP (see **Figure 6a**) show more variable visibility progress in the IMPROVE monitoring data 2000-2018 and in the 2028 visibility projections.

Clearest days at all western Class I areas have improved between 2000 and 2018 and are projected to continue to improve by 2028 at almost all western Class I areas.

EPA Volcanic adjustment (August 2021) for IMPROVE monitors at Hawai'i Volcano (HAVO1) and Haleakalā (HALE1) National Parks:

EPA defined an adjustment to ammonium sulfate to account for episodic volcanic events at Hawai'i Volcano (HAVO1) and Haleakalā (HALE1) National Parks. EPA's adjustment follows the same methodology as defined in December 2018 guidance to account for episodic extreme fire or dust events using IMPROVE measurements of carbon or crustal materials. EPA's adjustment for volcanic contributions uses IMPROVE daily ammonium sulfate measurements for the years 2000-2014, defines the average 95th percentile value for each year, and selects the lowest annual value as the threshold to assign ammonium sulfate daily measurements above that threshold as episodic volcanic (natural) contributions. After accounting for episodic volcanic contributions to ammonium sulfate, impairment is calculated following EPA guidance. By assigning maximum ammonium sulfate values as natural rather than anthropogenic, the days that are defined as most impaired by anthropogenic contributions shift. Ammonium sulfate still dominates the most impaired days, suggesting that not all volcanic contributions are accounted for using a 95th percentile threshold.

In addition to the volcanic adjustment, to assure a complete IMPROVE data set for Haleakalā National Park, EPA also applied data substitution methods to merge data from two separate IMPROVE monitor locations that have represented the Haleakalā NP Class I area over the 2000-2018 period (HALE1 and Haleakala Crater, HACR1). The combined data set is referred to as HALE_RHTS.

EPA also provided 2028 visibility projections for the volcano adjusted data sets, HAVO1_VADJ and HALE_RHTS_VADJ, as described in EPA's Technical Support Document for Updated 2028 Regional Haze Modeling for Hawaii, Virgin Islands, and Alaska (August 2021). EPA 2028 visibility projections for HAVO1_VADJ and HALE_RHTS_VADJ are displayed in aerosol extinction in TSS Modeling Express Chart #20 (equivalent to TSS Modeling Chart #3). TSS Modeling Express Chart #21 (equivalent to TSS Modeling Chart #3) displays 2028 visibility projections in deciview

for HAVO1_VADJ and HALE_RHTS_VADJ, the 2000-2018 volcano-adjusted monitoring data, estimated natural conditions in 2064, and the Uniform Rate of Progress for the volcano adjusted data for the most impaired days or clearest days at these two Class I areas.

TSS Modeling Express Tool #8 displays a table for each state listing all federal Class I areas in that state comparing the 2014-2018 5-year average IMPROVE observations to the 2028OTBa2 and 2028PAC2 visibility projections in deciview, calculated using the 3 WRAP projection methods. **Table 11** illustrates the 2028 visibility projection results for the state of Colorado. Note that Colorado did not define Potential Additional Controls for sources in Colorado for 2028PAC2, nonetheless, small changes in visibility were projected for 2028PAC2 due to PAC2 control assumptions in other WRAP states.

Table 11. 2028 Visibility Projections for the most impaired days at Class I areas in Colorado for the 2028 On the Books (2028OTBa2) and 2028 Potential Additional Controls (2028PAC2) model scenarios and 3 WRPA projection methods. TSS Modeling Express Tool #8

CO - 2028 Visibility Projections Summary

Most Impaired Days *(defined by EPA guidance [1])*

Class I Area IMPROVE Monitor	IMPROVE 2014-2018	2028 OTBa2 Model: EPA M.I.D.	2028 OTBa2 Model: EPA MID w/o Fire	2028 OTBa2: Modeled MID	2028 PAC2 Model: EPA M.I.D.	2028 PAC2 Model: EPA MID w/o Fire	2028 PAC2: Modeled MID
GRSA1	8.02 dv	7.55 dv	7.5 dv	7.33 dv	7.53 dv	7.49 dv	7.31 dv
MEVE1	6.51 dv	6.19 dv	6.1 dv	5.97 dv	6.18 dv	6.08 dv	5.94 dv
MOZI1	5.47 dv	4.96 dv	4.93 dv	4.94 dv	4.95 dv	4.92 dv	4.92 dv
ROMO1	8.41 dv	7.6 dv	7.56 dv	7.46 dv	7.59 dv	7.55 dv	7.44 dv
WEMI1	6.55 dv	6.12 dv	6.03 dv	5.89 dv	6.1 dv	6.02 dv	5.86 dv
WHRI1	4.98 dv	4.53 dv	4.49 dv	4.39 dv	4.52 dv	4.48 dv	4.37 dv

1) U.S. EPA. December 2018. Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program. EPA-454/R-18-010

9.0 Adjustments to the Uniform Rate of Progress Glidepath

EPA guidance (December 2018) allows a State to propose an adjustment to the URP glidepath to account for visibility contributions from anthropogenic emissions outside the U.S. or from emissions from wildland prescribed fires that meet specific land management objectives and apply basic smoke management practices. The EPA Administrator may approve proposed

adjustments to the URP glidepath that follow "scientifically valid data and methods." EPA's regional haze modeling Technical Support Document (September 2019) demonstrates adjustments to the 2064 endpoint of the URP glidepath using source apportionment results for international anthropogenic or wildland prescribed fire emissions from the EPA 2028 model scenario.

WRAP methods to adjust the 2064 endpoints for the URP glidepath to account for international emissions or wildland prescribed fire emissions are described in detail in WRAP Procedures for Making Visibility Projections and Adjusting Glidepaths (March 2021). The WRAP adjustments to the URP glidepath are based on 2028OTBa2 source apportionment results for international anthropogenic and wildland prescribed fire. Consistent with the methods evaluated in the EPA Technical Support Document, WRAP evaluated five approaches using 2028OTBa2 source apportionment results to adjust the 2064 endpoints. 2028 source apportionment results were applied in a relative sense (model results normalized to 2028 visibility projections) or an absolute sense (unadjusted absolute model results). 2064 endpoints were defined using IMPROVE natural conditions estimated for 2000-2014 or using 2028 source apportionment results for natural source contributions.

After review of the initial glidepath adjustment results, WRAP recommended that adjustment of the URP glidepath for Class I areas in western states use 2028 source apportionment results in a relative sense and use EPA estimated natural conditions for the 2064 endpoint for one of two options:

- International anthropogenic contribution normalized to IMPROVE monitoring data and added to EPA estimated natural conditions (International).
- International anthropogenic plus Wildland Prescribed fire combined contributions normalized to IMPROVE monitoring data and added to EPA estimated natural conditions (International + wildland Rx fire)

Note that wildland prescribed fire events in the 2028 OTBa2model scenario reflect the same events as modeled for 2014v2. Wildland prescribed fire events may not occur on most impaired days in 2014v2. Location, timing, frequency, magnitude, and duration of wildland prescribed fire events vary geographically, seasonally, and year to year. Therefore, interpretation of wildland prescribed fire contributions on most impaired days for the 2028OTBa2 source apportionment results and for the 2064 adjustment to the URP glidepath is uncertain.

TSS Modeling Express Chart #5 illustrates the Regional Haze Uniform Rate of Progress (URP) Glidepath as defined by EPA guidance and the two WRAP alternative glidepath end point adjustments for 2064 (International, International + Wildland Prescribed Fire.)

The URP glidepath (in deciviews) for most impaired days and the optional glidepath adjustments all start from the 2000-2004 5-year baseline for most impaired days and draw a straight line to estimated natural conditions in 2064. All 2064 endpoints use EPA estimates of natural conditions based on 2000-2014 IMPROVE data. Annual average deciview for 2000 to

2018 most impaired days are illustrated as points. IMPROVE 2000-2004 and 2014-2018 5-year average deciview values are illustrated as solid lines. Users can choose to display 2028OTBa2 and/or 2028PAC2 visibility projections for 1-3 projection methods and to display 2064 endpoint without adjustment or adjustment for either international anthropogenic emissions or international anthropogenic plus wildland prescribed fire emissions. The 2028OTBa2 EPA without fire projection method is the default setting for purposes of comparing 2028 visibility projections to the adjustment glidepath.

Figures 8a and 8b illustrate examples of TSS Modeling Express Chart #5 for Yellowstone (YELL2) and Mesa Verde (MEVE1) National Parks.

Interpretation: At YELL2, the 2028OTBa2 EPA without fire projection is above the URP glidepath. Adding International anthropogenic contributions to the 2064 endpoint raises the adjusted glidepath in 2028 to be above the 2028OTBa2 EPA without fire projection value. The second adjustment to the 2064 endpoint (adding wildland prescribed fire contribution to the international anthropogenic contribution) slightly raises the slope of the glidepath compared to international emissions alone.

At MEVE1, the 2028 visibility projection is below the URP glidepath. Adjustment of the 2064 endpoint for the international anthropogenic contribution raises the slope of the glidepath; adjustment for wildland prescribed fire has a negligible change to the adjusted glidepath.

At most Class I areas in the western U.S., application of the recommended methods to adjust the 2064 endpoint raises the slope of the URP glidepath. Western states will independently determine whether or not to use the URP glidepath adjustments in their regional haze planning.

Figure 8a. 2028 Visibility Projections compared to adjustments to the Uniform Rate of Progress Glidepath for most impaired days at the Yellowstone National Park (YELL2) IMPROVE monitor. TSS Modeling Express Chart #5.

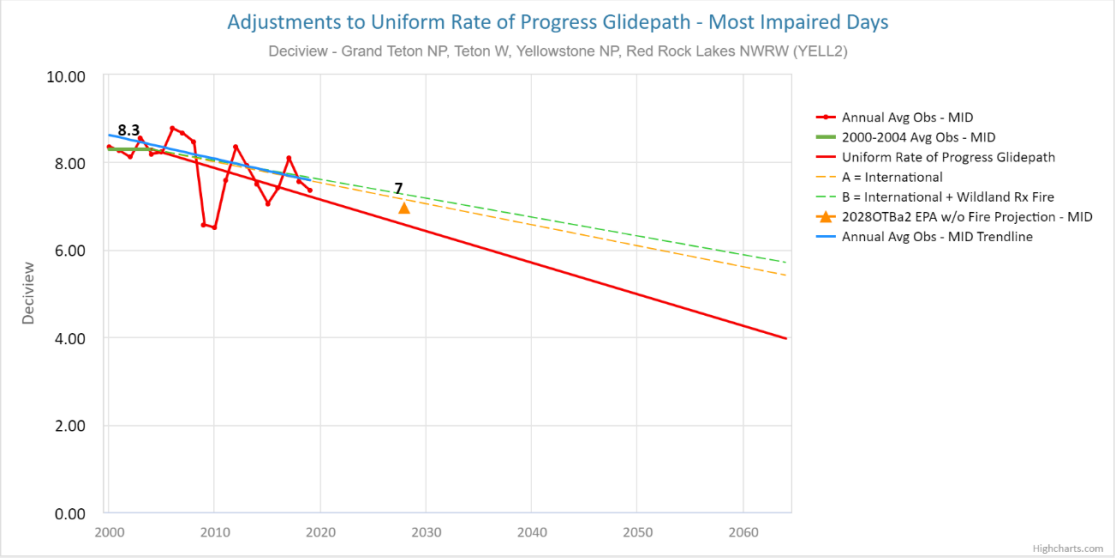
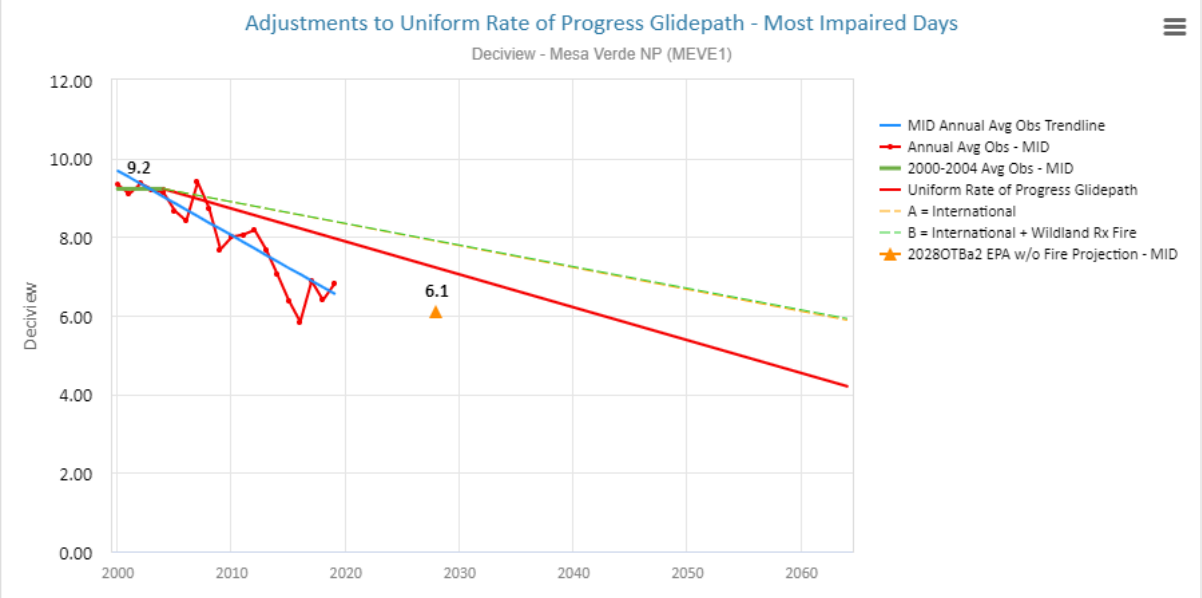


Figure 8b. 2028 Visibility Projections compared to adjustments to the Uniform Rate of Progress Glidepath for most impaired days at the Mesa Verde National Park (MEVE1) IMPROVE monitor. [TSS Modeling Express Chart] #5



10.0 Regional (High-level) Source Apportionment

WRAP Source Apportionment methods are described in the run specification sheet for [High-Level and Low-Level Source Apportionment Modeling] using the RepBase2 and 2028OTBa2 model scenarios (September 2020).

Purpose: Regional source apportionment results for U.S. anthropogenic, international anthropogenic, fire, and natural source contributions at each IMPROVE site representing western Class I areas were used as follows:

- Modeled most impaired days (ModMID) were defined based on RepBase2 source apportionment results. ModMID days were ranked by modeled U.S. anthropogenic contributions as a fraction of total aerosol light extinction. ModMID days are used as one of the WRAP alternative 2028 projection methods (see Section 7).
- 2028OTBa2 modeled international and U.S. wildland prescribed fire contributions were used as an option to adjust the 2064 endpoint of the URP glidepath for the most impaired days (see Section 9).
- Along with 2002 Hindcast scenario, RepBase2 and 2028OTBa2 regional source apportionment results for total aerosol light extinction were used to define a U.S. Anthropogenic Emissions Rate of Progress (see Section 12).

The CAMx photochemical model version 7.0 with the Particle Source Apportionment tool (PSAT) was applied at a regional level to separate U.S. anthropogenic contributions from those of fire, natural, and international anthropogenic contributions for the representative baseline period (2014-2018, RepBase2) and a future year, 2028OTBa2. CAMx with PSAT tracked gaseous and particle air emissions from sources through atmospheric dispersion, photochemical reactions, and transport to receptors (the 12-km modeling grid cell where the IMPROVE monitor is located), as defined in **Table 12**. Aerosol concentrations at the receptor include the direct products of primary gaseous and particle emissions and secondary aerosol formation.

Source contributions were defined for the following aerosols:

- Ammonium nitrate (AmmNO3)
- Ammonium sulfate (AmmSO4)
- Organic mass from carbon (OMC)
    - Primary Organic Aerosol (POA)
    - Secondary Organic Aerosols
        - Anthropogenic (SOAA)
        - Biogenic (SOAB)
- Primary Elemental Carbon (EC)
- Primary Fine Soil
- Primary Coarse Mass
- Seasalt

Table 12. PSAT emissions tracers mapped to IMPROVE aerosol species at the model receptor

PSAT Tracer Description	IMPROVE Species Name (TSS label)	Mapping between IMPROVE and PSAT species (concentration in μg/m3)	Notes
Particulate Sulfate (PS4)	Ammonium Sulfate (AmmSO4)	AmmSO4 = 1.375 * PS4	Factor 1.375 converts sulfate ion to fully neutralized ammonium sulfate
Particulate Nitrate (PN3)	Ammonium Nitrate (AmmNO3)	AmmNO3 = 1.29 * PN3	Factor 1.29 converts nitrate ion to fully neutralized ammonium nitrate
Primary Elemental Carbon (PEC)	Elemental Carbon (EC)	EC = PEC	
Primary Organic Aerosol (POA)	Organic Mass from Carbon (OMC)	OMC = POA +SOAA + SOAB	Secondary Organic Aerosols (SOA) are not explicitly tracked by source group. SOA are derived from AVRG concentration files and are operationally assigned to anthropogenic (SOAA) or biogenic (SOAB) source groups. All SOAA is assigned to U.S. anthropogenic source category and all SOAB is assigned to Natural source category.
Aluminum (PAL)	Fine Soil (Soil)	Soil = 2.2*PAL + 2.49*PSI + 1.63*PCA + 2.42*PFE + 1.94*PTI	Soil mapping is consistent with IMPROVE definition
Silicon (PSI)			
Calcium (PCA)			
Iron (PFE)			
Titanium (PTI)			
Coarse Crustal PM (PCC)	Coarse Mass (CM)	CM = PCC + PCS	
Other Coarse Particulate (PCS)			
Chloride (PCL)	Sea Salt	Sea Salt = 1.8 * PCL	Chloride is not tracked by Source Apportionment. It is obtained from the AVRG concentration files. All Chloride is assigned to sea salt. All sea salt is assigned to the "natural" source group. All other source group contributions to sea salt are 0.

Due to computational constraints, the secondary organic aerosols (SOA) family of reactive tracers were not used to track SOA at the receptor; rather SOA were operationally assigned to anthropogenic (SOAA) or biogenic (SOAB) contributions based on the chemical signatures (e.g., isoprene was assigned as biogenic in origin; benzene was assigned as anthropogenic in origin.) For purposes of compositing regional source categories, all SOAA were assigned to the U.S. anthropogenic source category and all SOAB were assigned to the Natural source category.

Regional source apportionment results for RepBase2 and 2028OTBa2 aerosol light extinction are displayed in TSS Modeling Express Tools # 10-16 for 15 source groups that are composited into 6 source categories as listed below. Abbreviations correspond to the source labels used in TSS Modeling Express Tools #10-16.

- U.S. Anthropogenic (USAnthro)
    - U.S. anthropogenic (AntUS)
    - U.S. agricultural fire (AgfireUS)
    - Secondary Organic Aerosol-Anthropogenic (SOAA)
    - Commercial Marine Vessels (CMVUS)
    - U.S. anthropogenic contributions from outside the CAMx 36-km domain boundary as defined by the GEOS-Chem global model. (BC-US)
- U.S. Wildfire (WFUS)
- U.S. Wildland Prescribed fire (RxUS)
- Canadian and Mexican fires (OthFr)
- Natural
    - Natural (Nat)
    - Secondary Organic Aerosol -Biogenic (SOAB)
    - Natural contributions from outside the CAMx 36-km domain boundary as defined by the GEOS-Chem global model. (BC-Nat)
- International Anthropogenic (IntlAnthro)
    - International Anthropogenic contributions from outside the CAMx 36-km domain boundary as defined by the GEOS-Chem global model. (BC-Int)
    - Canadian Anthropogenic (AntCAN)
    - Mexican Anthropogenic (AntMEX)
    - Commercial Marine vessels – International (beyond 200km from U.S. coast) (CMV_nonUS)

Users can choose to display source apportionment results in TSS Modeling Express Tools # 10-16 for most impaired days (EPA default 2014 IMPROVE days), modeled most impaired days, or clearest days. Charts in this document provide examples for 2014 IMPROVE most impaired days only.

Users can choose to display source apportionment results for total aerosol extinction or for individual aerosols species extinction.

Modeled source contributions to light extinction in TSS Modeling Express Tools # 10-16 are not normalized to IMPROVE monitoring data. Model performance should be considered when interpreting source apportionment results. Average and daily model performance for most impaired days as displayed in TSS Modeling Express Tool # 1 and 2 provide insight to confidence to place in source apportionment results for individual aerosol species.

TSS Modeling Express Tool # 10 defines in a single stacked barchart the light extinction contributions from 15 source groups for the RepBase2 or 2028OTBa2 model scenarios. **Figures 9a and 9b** illustrate regional source apportionment for 2028OTBa2 for Yellowstone NP (YELL2) and Mesa Verde NP (MEVE1), respectively.

Interpretation: At YELL2, U.S. anthropogenic emissions in 2028OTBa2 are projected to contribute less than 20% of total aerosol light extinction (left chart) and less than 30% of extinction due to AmmNO3 extinction (right chart). At MEVE1, U.S. anthropogenic emissions in 2028OTBa2 are projected to contribute less than 30% of total extinction (left) and 54% of AmmNO3 extinction (right).

Figure 9a. 2028OTBa2 Regional Source Apportionment for most impaired days at the Yellowstone National Park (YELL2) IMPROVE monitor for 15 source group contributions to total aerosol light extinction (Mm^{-1}) (left) or to Ammonium nitrate light extinction (right). TSS Modeling Express Tool # 10.

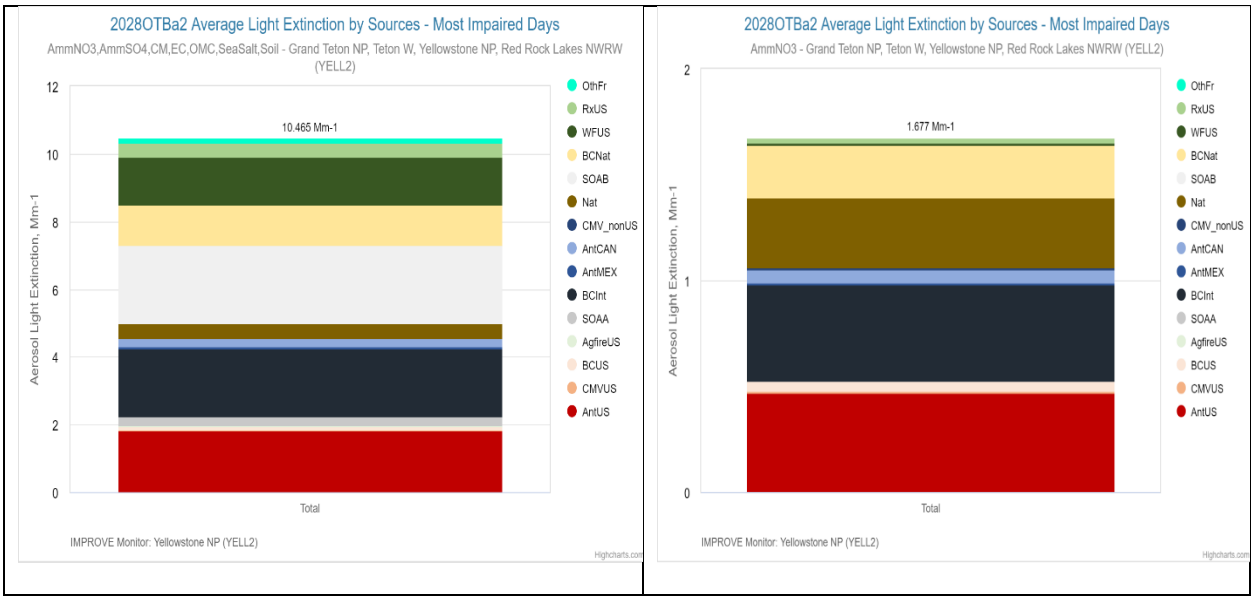
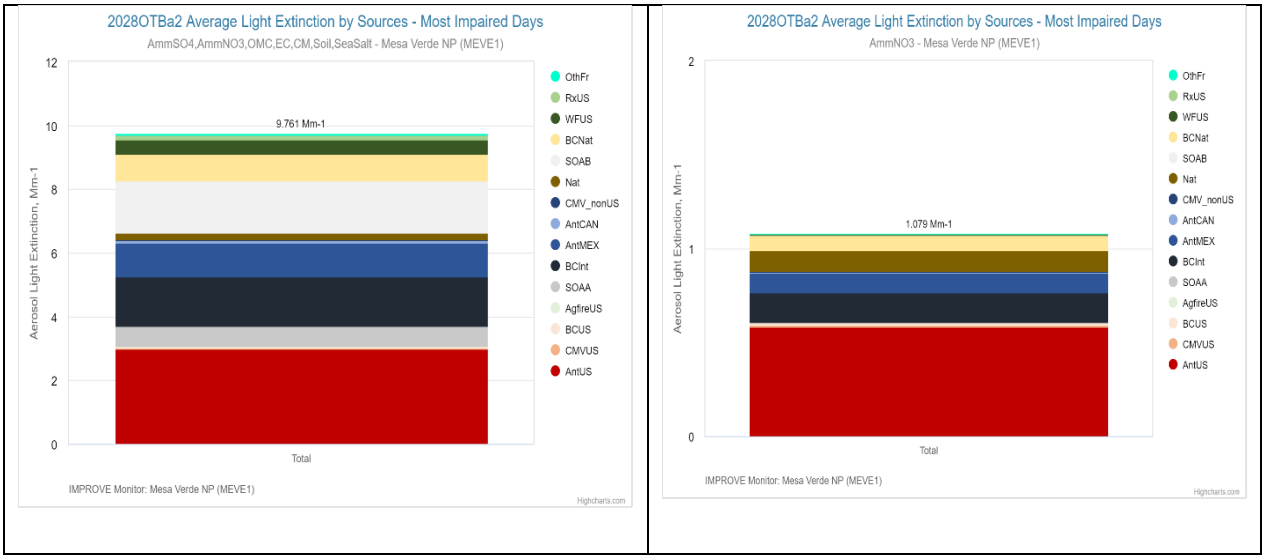


Figure 9b. 2028OTBa2 Regional Source Apportionment for most impaired days at the Mesa Verde National Park (MEVE1) IMPROVE monitor for 15 source group contributions to total aerosol light extinction (Mm^{-1}) (left) or to Ammonium nitrate light extinction (right). TSS Modeling Express Tool # 10.

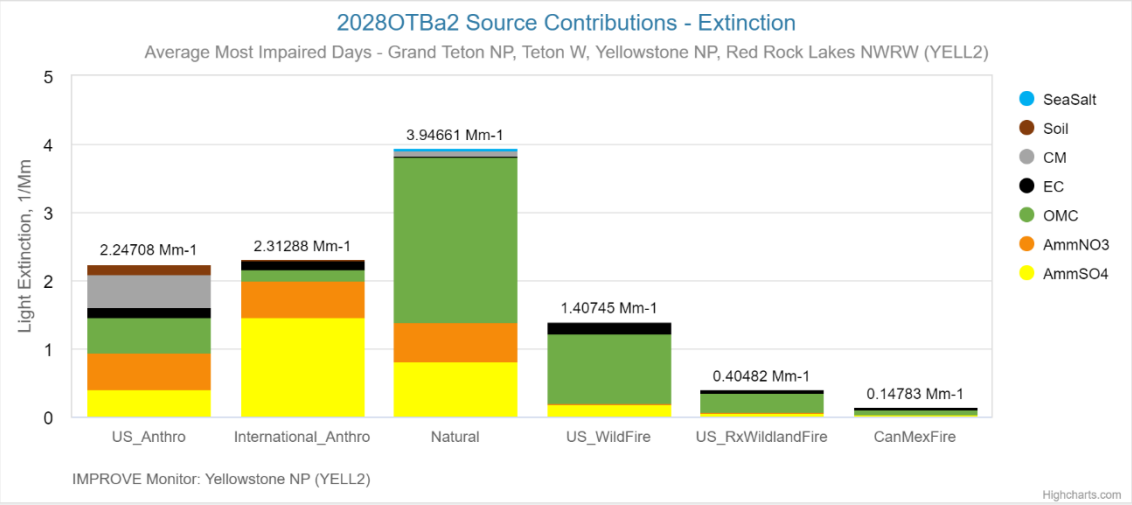


TSS Modeling Express Tool # 11, illustrated in **Figure 10a** for YELL2 and **Figure 10b** for MEVE1, displays speciated aerosol light extinction on most impaired days for RepBase2 or 2028OTBa2, by pollutant, for each of 6 source categories.

Interpretation: For YELL2, in 2028OTBa2, the natural source category is the largest source contribution, even on the most impaired days. Organic carbon dominates the natural and fire categories. International anthropogenic source contributions are equal to U.S. anthropogenic contributions and smaller than natural plus fire contributions. Ammonium sulfate and ammonium nitrate dominate the international anthropogenic category. For U.S. anthropogenic contributions, ammonium nitrate, ammonium sulfate, organic carbon, and coarse mass are projected to have similar contributions. U.S. wildland prescribed fire has very small contributions at YELL2.

The 2028OTBa2 visibility projections for YELL2 are projected to be above the URP glidepath (see **Figure 7a**, TSS Modeling Express Tool # 4) because U.S. anthropogenic sources are a smaller fraction of total aerosol extinction compared to natural, international, and fire contributions. Adding the 2028OTBa2 international contribution to the 2064 endpoint raises the URP glidepath above the 2028OTBa2 visibility projection for YELL2 (see **Figure 8a**, TSS Modeling Express Tool # 5). Adding 2028OTBa2 wildland prescribed fire to the 2064 endpoint has a very small impact on the slope of the URP glidepath because U.S. wildland prescribed fire has a small contribution to total aerosol extinction.

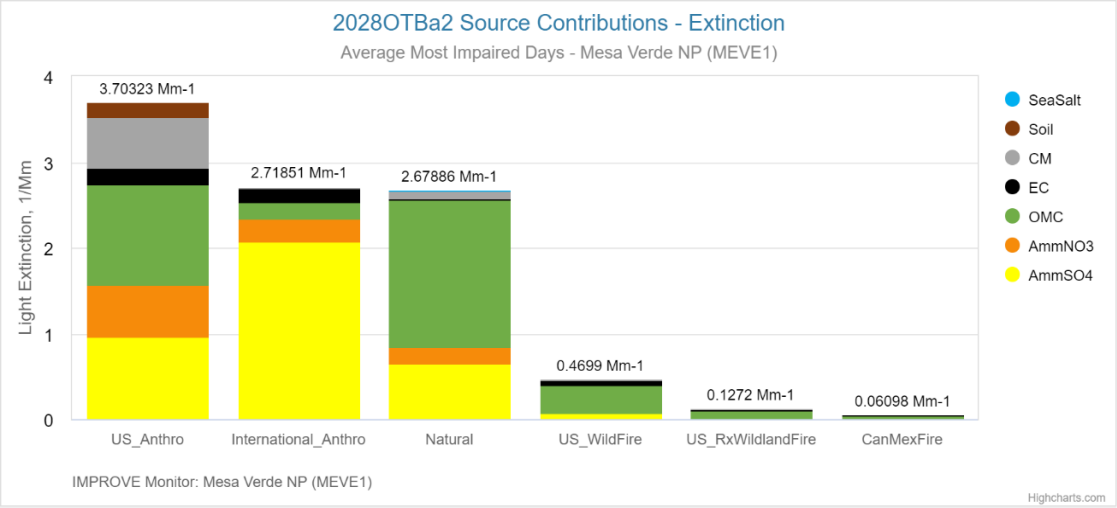
Figure 10a. 2028OTBa2 Regional Source Apportionment of Speciated Aerosol Light Extinction (Mm^{-1}) for most impaired days at the Yellowstone National Park (YELL2) IMPROVE monitor for U.S. Anthropogenic, International anthropogenic, Natural, and Fire source categories, with component species contributions. TSS Modeling Express Tool # 11.



Interpretation: For MEVE1, in 2028OTBa2, U.S. anthropogenic emissions have the largest contributions to total aerosol extinction, divided between ammonium sulfate, ammonium nitrate, organic carbon, and coarse mass (**Figure 10b**). International anthropogenic and natural sources have equivalent, somewhat smaller contributions than U.S. anthropogenic sources. International anthropogenic contributions are dominated by ammonium sulfate, while natural sources and fires are dominated by organic carbon. U.S. wildland prescribed fire has very small contributions at MEVE1.

The 2028OTBa2 visibility projections for MEVE1 are projected to be below the URP glidepath (see **Figure 10a**, TSS Modeling Express Tool # 4) because U.S. anthropogenic sources are a larger fraction of total aerosol extinction compared to natural, international, and fire contributions and changes in the U.S. anthropogenic emissions between RepBase2 and 2028OTBa2 are reflected in changes to 2028OTBa2 visibility projections. Adding the 2028OTBa2 international contribution to the 2064 endpoint raises the URP glidepath for MEVE1 (see **Figure 11a**, TSS Modeling Express Tool # 5). Adding 2028OTBa2 wildland prescribed fire to the 2064 endpoint has a very small impact on the slope of the URP glidepath because U.S. wildland prescribed fire has a small contribution to total aerosol extinction.

Figure 10b. 2028OTBa2 Regional Source Apportionment of Speciated Aerosol Light Extinction (Mm^{-1}) for most impaired days at the Mesa Verde National Park (MEVE1) IMPROVE monitor for U.S. Anthropogenic, International anthropogenic, Natural, and Fire source categories, with component species contributions. TSS Modeling Express Tool # 11.



TSS Modeling Express Tool # 12 illustrated in **Figure 11a** for Yellowstone NP, YELL2, and **Figure 11b** for Mesa Verde NP, MEVE1, displays speciated aerosol light extinction on most impaired days for RepBase2 or 2028OTBa2, by source category, for each of 7 pollutants.

Interpretation: At YELL2, in 2028OTBa2, on the most impaired days, organic carbon is the largest contributor to total aerosol extinction and natural and fire sources are the largest contributors to organic carbon. International anthropogenic emissions are the largest contributor to AmmSO4. Natural, international anthropogenic, and U.S. anthropogenic emissions have comparable contributions to AmmNO3.

At MEVE1, in 2028OTBa2, on most impaired days, AmmSO4 and organic carbon are the largest contributors to total aerosol extinction. International emissions are the largest contributor to AmmSO4 and natural emissions are the largest contributor to organic carbon. U.S. anthropogenic emissions are the second largest contributors to AmmSO4 and organic carbon.

Figure 11a. 2028OTBa2 Regional Source Apportionment of Speciated Aerosol Light Extinction (Mm^{-1}) for most impaired days at the Yellowstone National Park (YELL2) IMPROVE monitor for 7 pollutants, with component U.S. Anthropogenic, International anthropogenic, Natural, and Fire contributions to each pollutant. [TSS Modeling Express Tool] # 12.

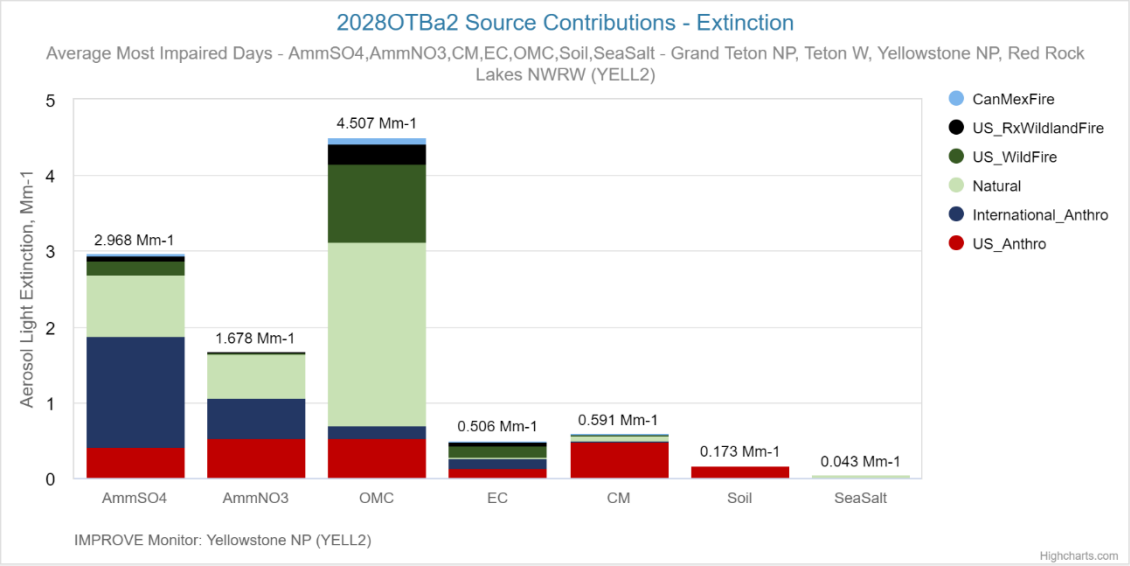
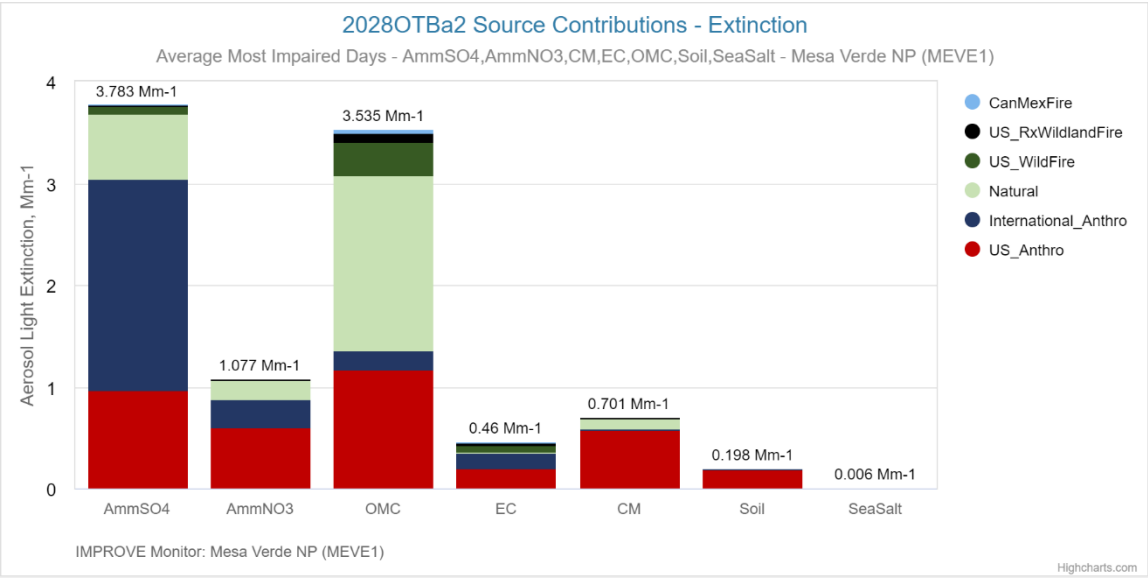


Figure 11b. 2028OTBa2 Regional Source Apportionment of Speciated Aerosol Light Extinction (Mm^{-1}) for most impaired days at the Mesa Verde National Park (MEVE1) IMPROVE monitor for 7 pollutants, with component U.S. Anthropogenic, International anthropogenic, Natural, and Fire contributions to each pollutant. [TSS Modeling Express Tool] # 12.



TSS Modeling Express Tool # 13 illustrated in **Figure 12a** for Yellowstone NP (YELL2) and **Figure 12b** for Mesa Verde NP (MEVE1), displays aerosol light extinction on individual 2014 IMPROVE most impaired days for RepBase2 or 2028OTBa2 source apportionment, by source category.

Interpretation: Comparing Figures 15a and 15b, U.S. anthropogenic contributions in 2028OTBa2 are a larger fraction of daily aerosol light extinction at Mesa Verde NP than at Yellowstone NP. U.S. anthropogenic contributions dominate on the two most impaired days with the highest total aerosol extinction at MEVE1. At YELL2, international anthropogenic and natural sources are equal or greater contributors to daily aerosol light extinction than U.S. anthropogenic sources. These source apportionment results are consistent with the 2028OTBa2 visibility projections for these two sites (see **Figure 7a**, TSS Modeling Express Tool # 4).

Figure 12a. 2028OTBa2 Regional Source Apportionment of Aerosol Light Extinction (Mm^{-1}) for 2014 IMPROVE daily most impaired days at the Yellowstone National Park (YELL2) IMPROVE monitor for U.S. Anthropogenic, International anthropogenic, Natural, and Fire emissions. TSS Modeling Express Tool # 13.

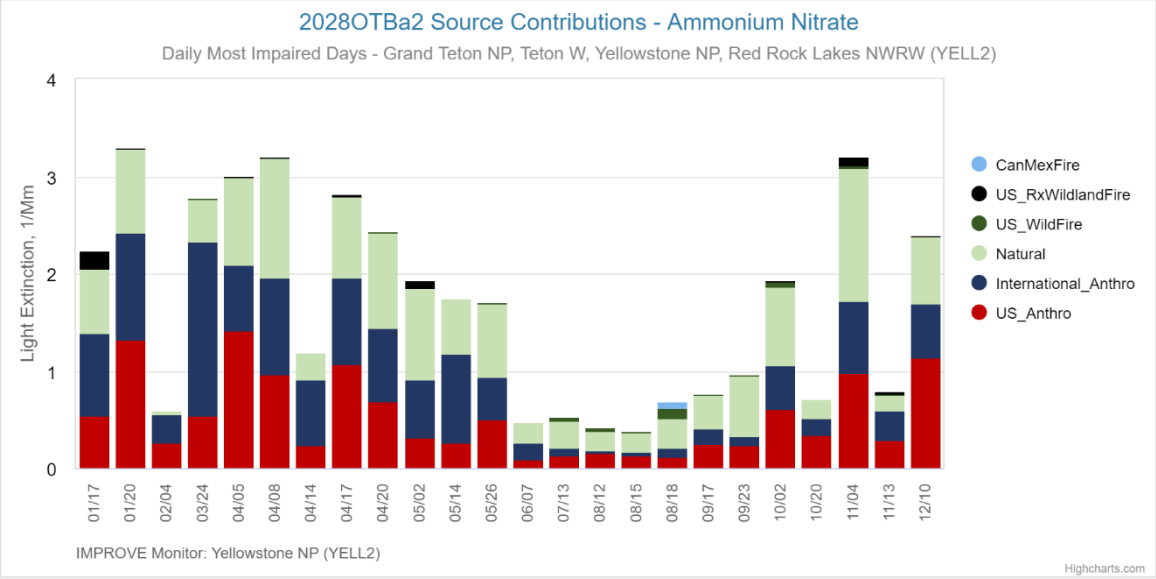
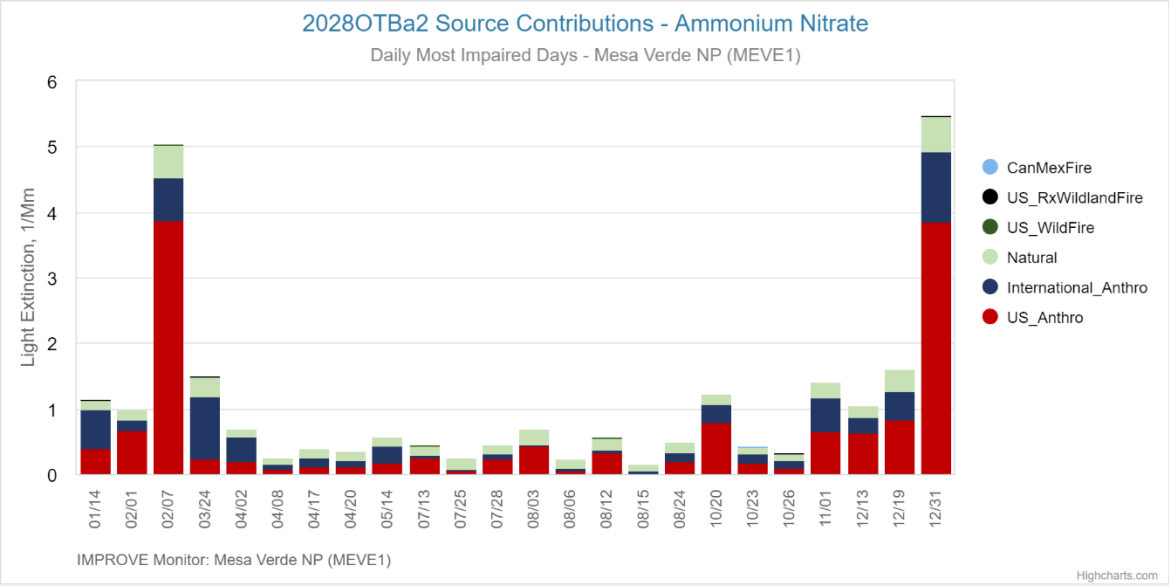


Figure 12b. 2028OTBa2 Regional Source Apportionment of Aerosol Light Extinction (Mm^{-1}) for daily 2014 IMPROVE most impaired days at the Mesa Verde National Park (MEVE1) IMPROVE monitor for U.S. Anthropogenic, International anthropogenic, Natural, and Fire emissions. TSS Modeling Express Tool # 13.



TSS Modeling Express Tool # 14 illustrated in **Figures 13a and 13b** for Yellowstone NP (YELL2) and **Figures 13c and 13d** for Mesa Verde NP (MEVE1) displays RepBase2 or 2028OTBa2 source apportionment results as a treemap (used to display hierarchal data.) Source categories are displayed in block colors with component source groups outlined within each source category total. Users can choose to display source apportionment results for total aerosol light extinction or single aerosol species extinction. Results in Figures 13a and 13c display total aerosol light extinction for 2028OTBa2; results in Figures 13b and 13d display light extinction due to AmmNO3 for 2028OTBa2.

Interpretation: at YELL2, for total aerosol extinction, natural sources are the largest contributors. International anthropogenic and U.S. anthropogenic have similar contributions, and wildfire is also an important source contribution. For AmmNO3, Natural, International anthropogenic and U.S. anthropogenic sources have very similar contributions. As shown in Figure 9a, at YELL2, U.S. anthropogenic emissions in 2028OTBa2 are projected to contribute less than 20% of total aerosol light extinction and less than 30% of extinction due to AmmNO3. These low fractions mean that it is more difficult to demonstrate changes visibility in response to changes in U.S. anthropogenic emissions.

At MEVE1, U.S. anthropogenic emissions are the largest source category for total aerosol extinction and for extinction due to AmmNO3 (Figures 13c, 13d). Visibility is more likely to respond to changes in U.S. anthropogenic emissions at MEVE1 than at YELL2.

Figure 13a. 2028OTBa2 Regional Source Apportionment of Total Aerosol Light Extinction (Mm^{-1}) for most impaired days at the Yellowstone National Park (YELL2) for source groups contributing to U.S. Anthropogenic, International anthropogenic, Natural, and Fire source categories. [TSS Modeling Express Tool] # 14.

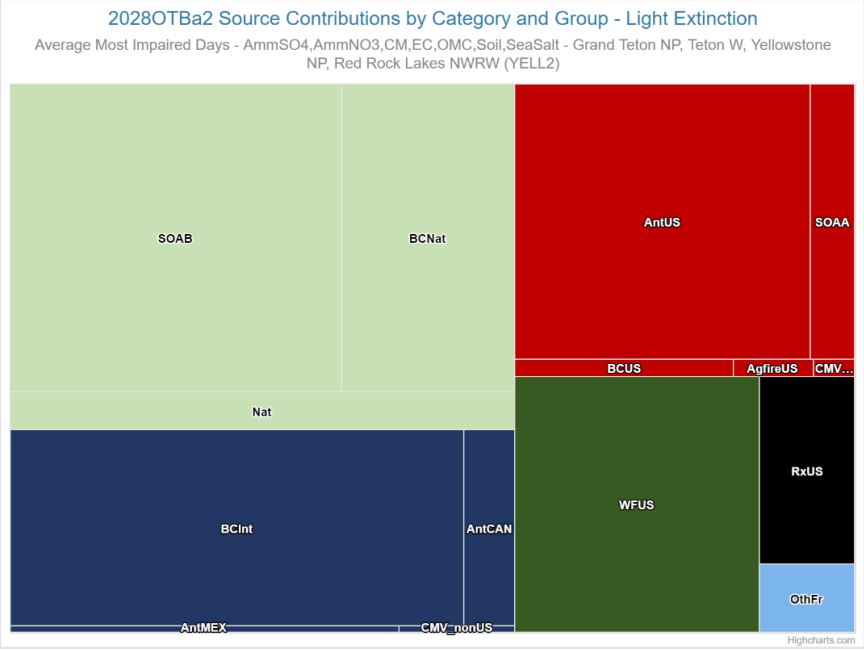


Figure 13b. 2028OTBa2 Regional Source Apportionment of Aerosol Light Extinction (Mm^{-1}) due to Ammonium nitrate for most impaired days at the Yellowstone National Park (YELL2) for source groups contributing to U.S. Anthropogenic, International anthropogenic, Natural, and Fire source categories. [TSS Modeling Express Tool] # 14.

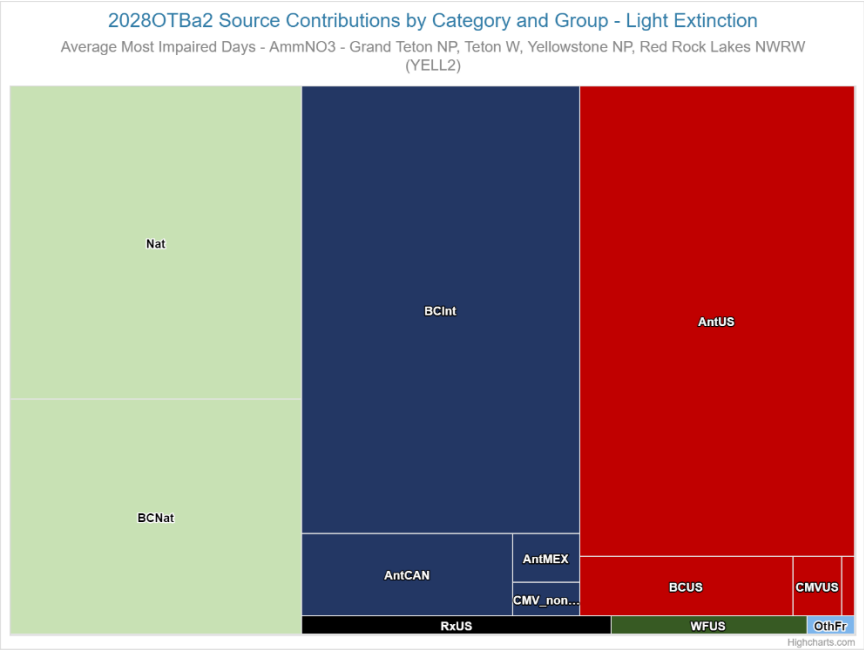


Figure 13c. 2028OTBa2 Regional Source Apportionment of Total Aerosol Light Extinction (Mm^{-1}) for most impaired days at the Mesa Verde National Park (MEVE1) for source groups contributing to U.S. Anthropogenic, International anthropogenic, Natural, and Fire source categories. [TSS Modeling Express Tool] # 14.

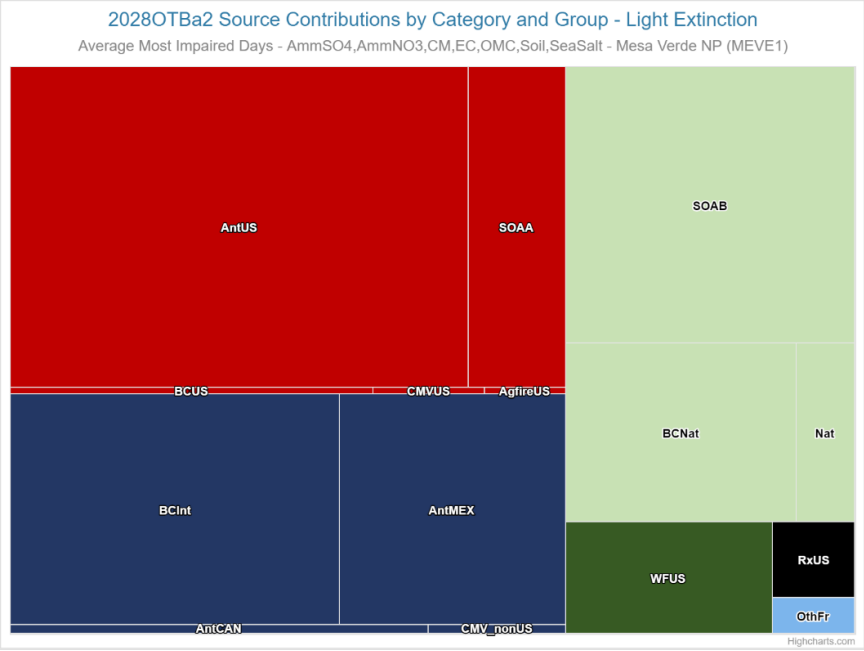
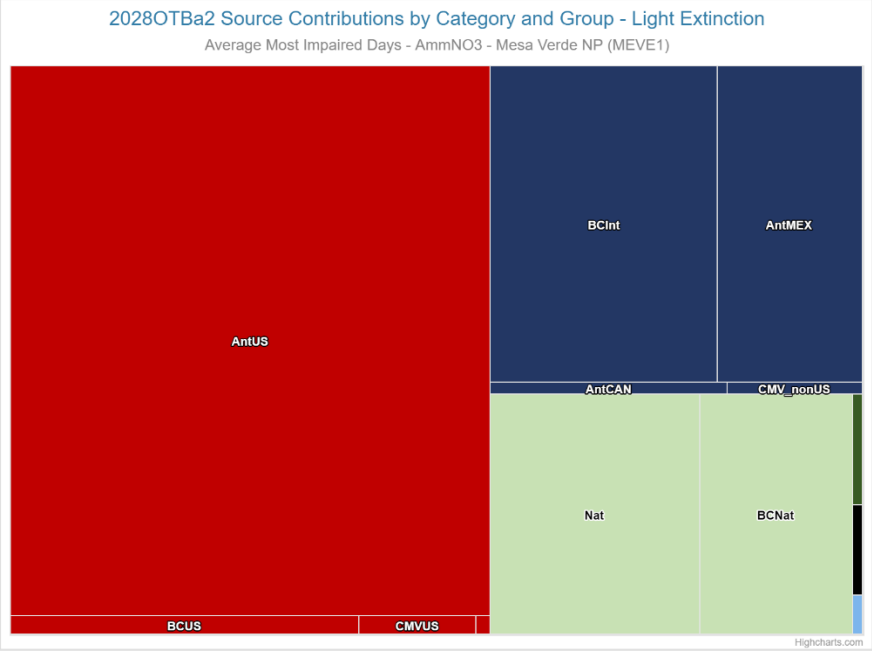


Figure 13d. 2028OTBa2 Regional Source Apportionment of Aerosol Light Extinction (Mm^{-1}) due to Ammonium Nitrate for most impaired days at the Mesa Verde National Park (MEVE1) for source groups contributing to U.S. Anthropogenic, International anthropogenic, Natural, and Fire source categories. [TSS Modeling Express Tool] # 14.



TSS Modeling Express Tool # 15 illustrated in **Figure 14a** for Yellowstone NP (YELL2) and **Figure 14b** for Mesa Verde NP (MEVE1), displays RepBase2 or 2028OTBa2 source apportionment results as a treemap (used to display hierarchal data.) Source categories are displayed in block colors with component aerosol species contributions outlined within each source category total. Users can choose to display source apportionment results for total aerosol light extinction or single aerosol species extinction. Results in Figures 14a and 14b display total aerosol light extinction for 2028OTBa2.

The same data are presented in TSS Modeling Express Tool #11 (Figures 10a and 10b.)

Interpretation: the tree map shows the aerosol species contributions to each source category. At both YELL2 and MEVE1, OMC is a large fraction of U.S. anthropogenic contributions, in addition to AmmNO3 and AmmSO4. OMC is also a large fraction of natural and fire contributions.

Figure 14a. 2028OTBa2 Regional Source Apportionment of Total Aerosol Light Extinction (Mm^{-1}) for most impaired days at the Yellowstone National Park (YELL2) for aerosol species contributions to U.S. Anthropogenic, International anthropogenic, Natural, and Fire source categories. TSS Modeling Express Tool # 15.

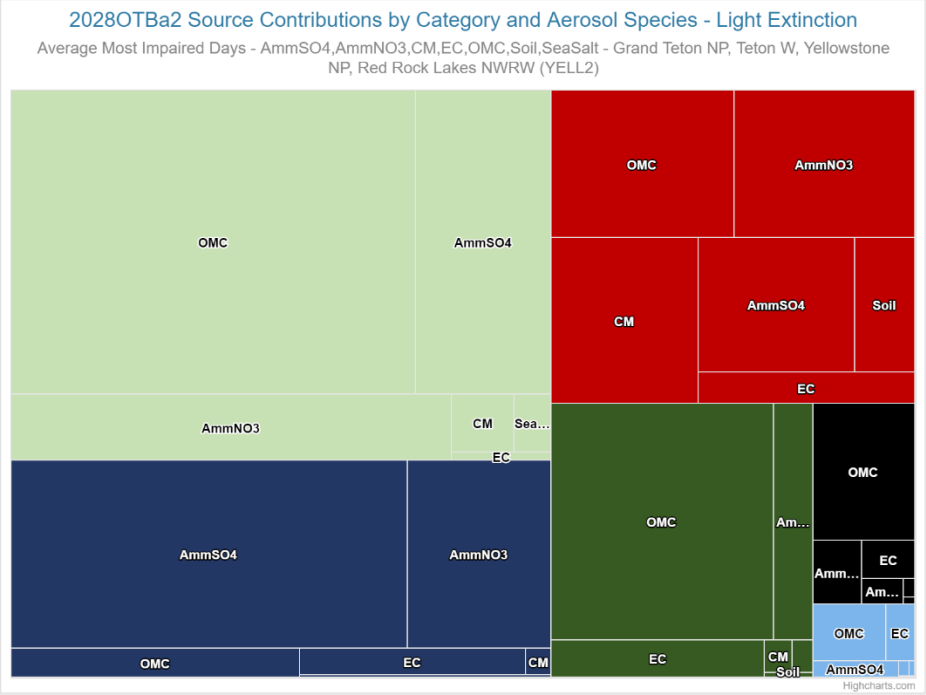
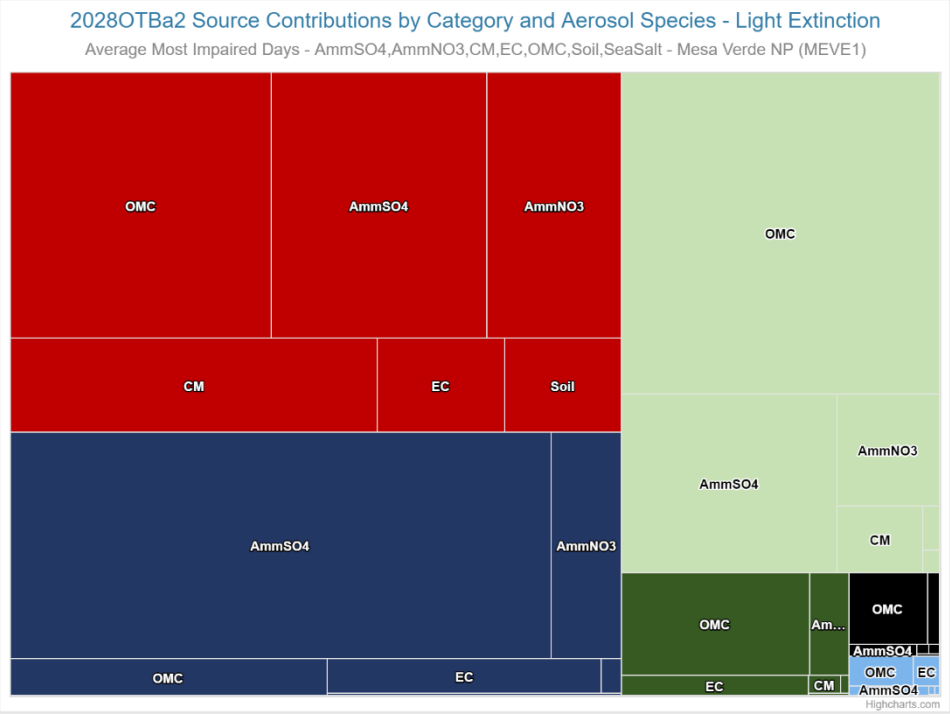


Figure 14b. 2028OTBa2 Regional Source Apportionment of Total Aerosol Light Extinction (Mm^{-1}) for most impaired days at the Mesa Verde National Park (MEVE1) for aerosol species contributions to U.S. Anthropogenic, International anthropogenic, Natural, and Fire source categories. TSS Modeling Express Tool # 15.



TSS Modeling Express Tool # 16 illustrated in **Figure 15a** for Yellowstone NP (YELL2) and **Figure 15b** for Mesa Verde NP (MEVE1), displays RepBase2 or 2028OTBa2 source apportionment results as a treemap (used to display hierarchal data.) Aerosol species contributions are displayed in block colors with component source groups outlined within each aerosol species. total. Users can choose to display source apportionment results for total aerosol light extinction or single aerosol species extinction. Results in Figures 15a and 15b display total aerosol light extinction for 2028OTBa2.

The same data are presented in TSS Modeling Express Tool #12 (Figures 11a and 11b.)

Interpretation: at YELL2, U.S. anthropogenic contributions are the third most important for OMC, AmmSO4, and AmmNO3. At MEVE1 U.S. anthropogenic contributions are the largest factor for AmmNO3 and the second largest for AmmSO4 and OMC.

Figure 15a. 2028OTBa2 Regional Source Apportionment of Total Aerosol Light Extinction (Mm^{-1}) for most impaired days at Yellowstone National Park (YELL2) for source category contributions to individual aerosol species. [TSS Modeling Express Tool] # 16.

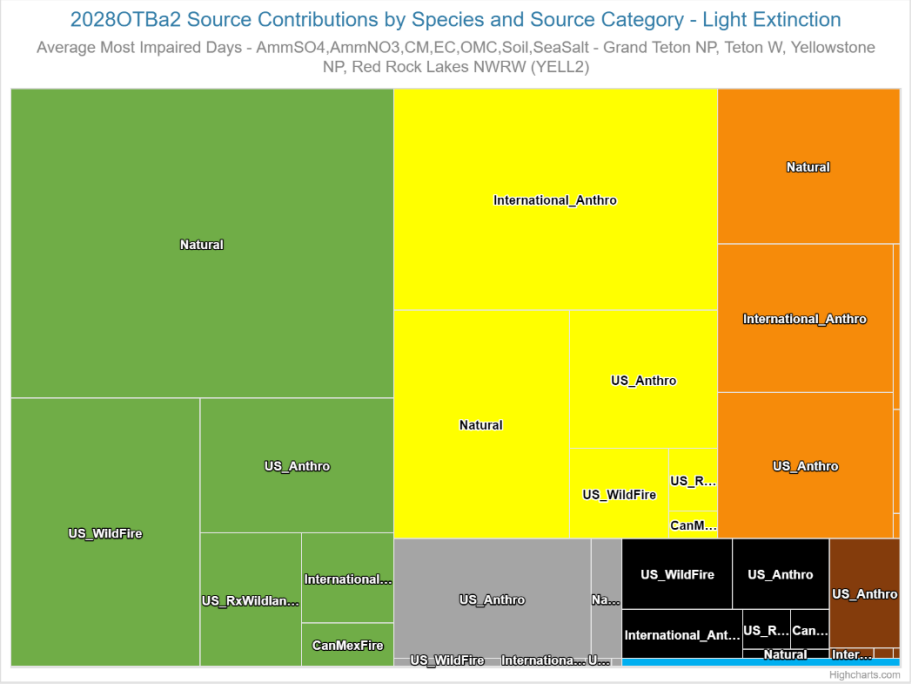
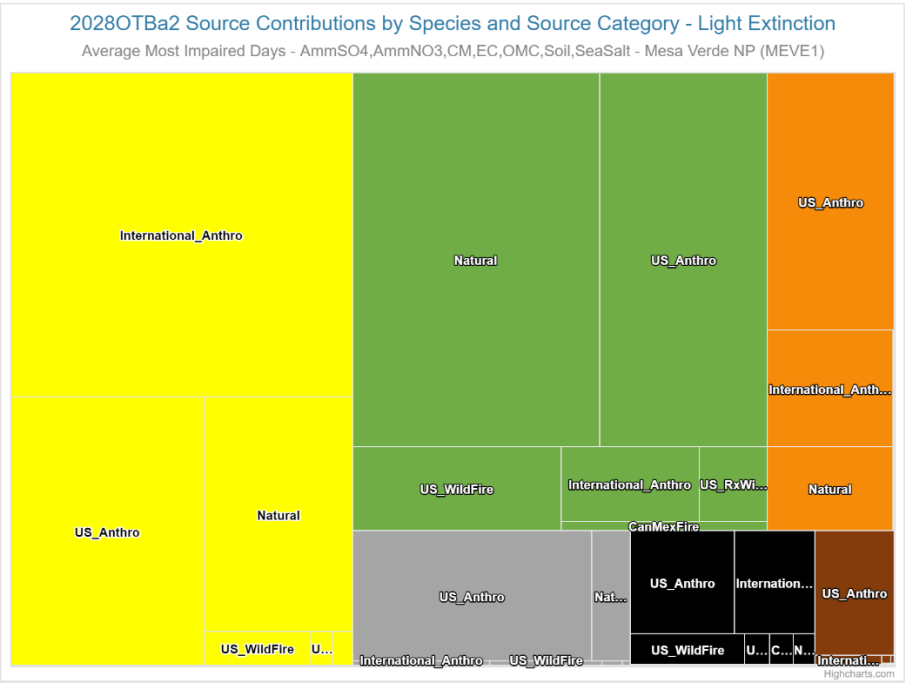


Figure 15b. 2028OTBa2 Regional Source Apportionment of Total Aerosol Light Extinction (Mm^{-1}) for most impaired days at Mesa Verde National Park (MEVE1) for source category contributions to individual aerosol species. [TSS Modeling Express Tool] # 16.



11.0 State and Sector (Low-level) Source Apportionment

For the future year 2028OTBa2 model scenario, PSAT was applied to further define U.S. anthropogenic contributions to AmmNO3 and AmmSO4 aerosols at western Class I areas from each of 13 WESTAR-WRAP states and all other non-WRAP U.S. states combined. Methods are further detailed in the run specification sheet for High-Level and Low-Level Source Apportionment Modeling using the RepBase2 and 2028OTBa2 model scenarios (September 2020).

State contributions to AmmNO3 and AmmSO4 were subdivided into five anthropogenic source categories:

- electric generating units (EGU)
- oil and gas (area plus point sources) (OilGas)
- remaining point sources (non-EGU)
- Mobile onroad, nonroad, rail, and commercial marine vessels (CMV 1, 2, and 3 within 200 km of U.S. coast) (Mobile)
- remaining anthropogenic sources (including Fugitive dust, Agriculture, Agricultural fire, residential wood combustion, and all remaining nonpoint sources)

For each Class I area, these results identify which source sectors and states are projected to have the greatest contributions in 2028OTBa2 to visibility impairment due AmmSO4 and AmmNO3. These results can assist states to prioritize which emissions reductions strategies might be most effective in improving visibility at western Class I areas.

The state and sector source apportionment results in TSS Modeling Express Tools # 9 are absolute model outputs; results are not normalized to IMPROVE monitoring data. Users can choose to display state and sector source apportionment results for most impaired days (EPA default 2014 IMPROVE days), modeled most impaired days, or clearest days. This document provides examples for most impaired days only.

TSS Modeling Express Tool # 9 illustrated in **Figures 16a and 16b** for Yellowstone NP (YELL2) and **Figures 16c and 16d** for Mesa Verde NP (MEVE1), displays RepBase2 or 2028OTBa2 source apportionment results for western states and source sectors for AmmNO3 or AmmSO4 light extinction, respectively.

Interpretation: at YELL2 PSAT projects that AmmNO3 contributions from individual states are 0.2 Mm^{-1} or less. PSAT identifies mobile sources from several western states as the most important U.S. anthropogenic contributors to AmmNO3 at YELL2 (**Figure 16a**). Idaho is shown as having the largest contributions to AmmNO3 from mobile, non-EGU and area sources.

For AmmSO4 at YELL2, PSAT projects that individual state contributions are small (0.15 Mm-1 or less). Non-EGU, EGU, and area sources in several states are identified as contributors.

Figure 16a. 2028OTBa2 State and Sector Source Apportionment of Ammonium Nitrate Aerosol Light Extinction (Mm^{-1}) for most impaired days at the Yellowstone National Park (YELL2) IMPROVE monitor. [TSS Modeling Express Tool](#) # 9

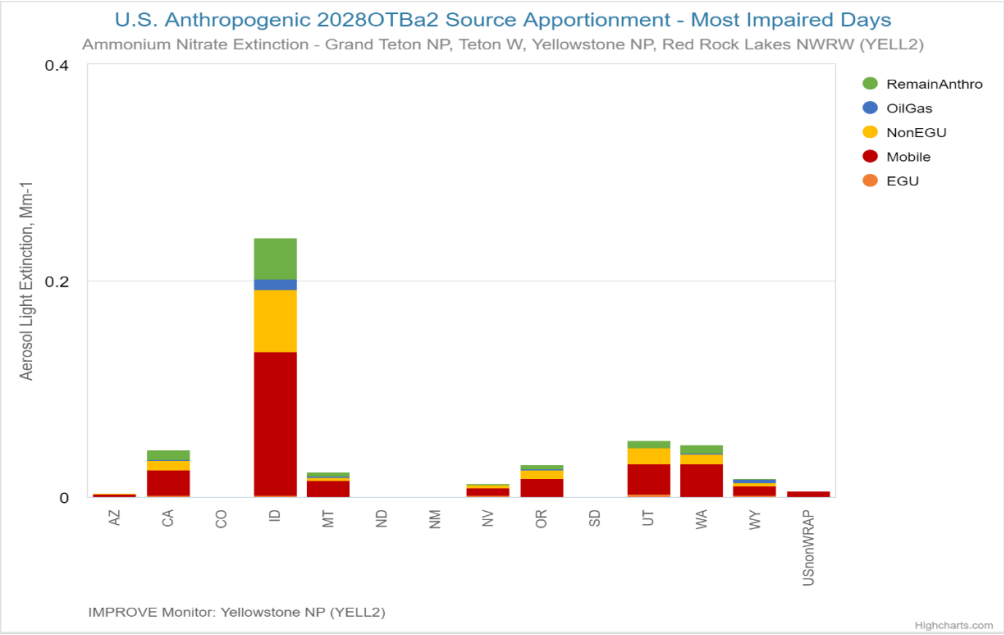


Figure 16b. 2028OTBa2 State and Sector Source Apportionment of Ammonium Sulfate Aerosol Light Extinction (Mm^{-1}) for most impaired days at the Yellowstone National Park (YELL2) IMPROVE monitor. [TSS Modeling Express Tool](#) # 9

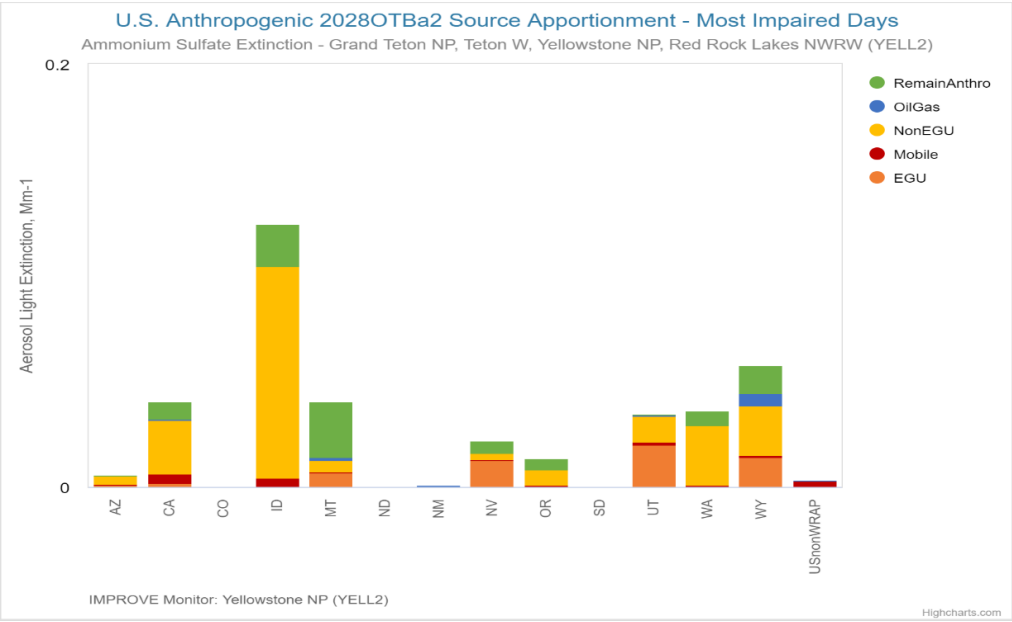


Figure 16c. 2028OTBa2 State and Sector Source Apportionment of Ammonium Nitrate Aerosol Light Extinction (Mm^{-1}) for most impaired days at the Mesa Verde National Park (MEVE1) IMPROVE monitor. [TSS Modeling Express Tool] # 9

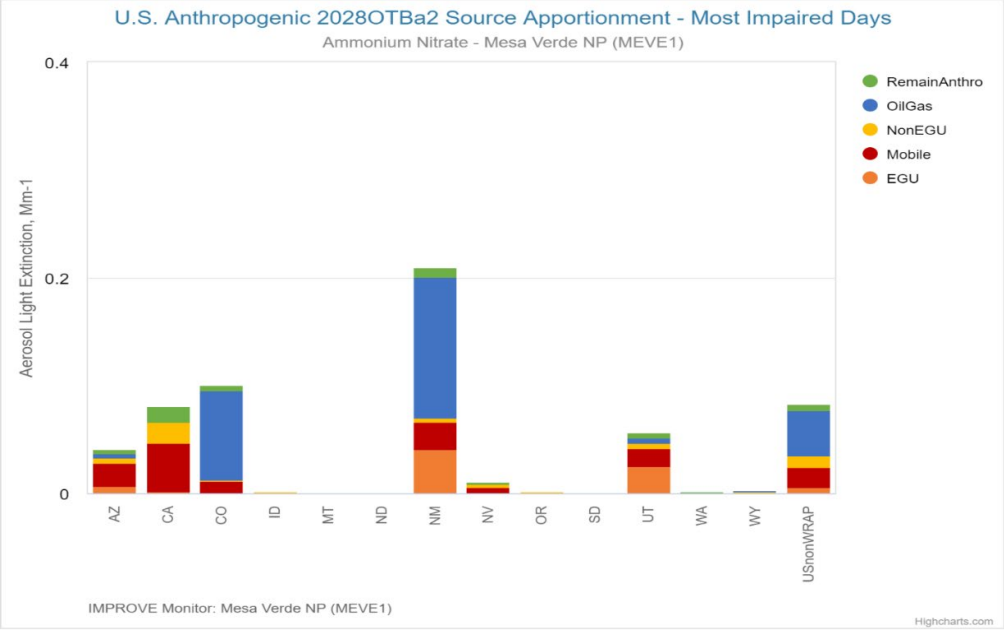
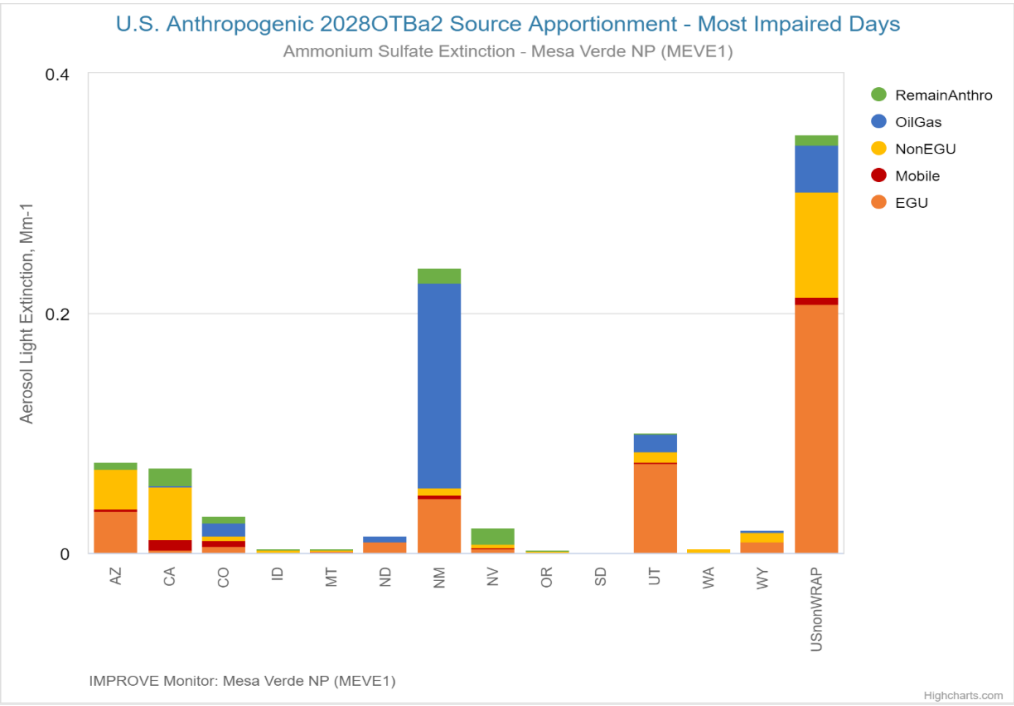


Figure16d. 2028OTBa2 State and Sector Source Apportionment of Ammonium Sulfate Aerosol Light Extinction (Mm^{-1}) for most impaired days at the Mesa Verde National Park (MEVE1) IMPROVE monitor. [TSS Modeling Express Tool] # 9



At MEVE1, AmmNO3 contributions from individual states are 0.2 Mm^{-1} or less. Oil and gas in NM, CO, and non-WRAP states are major contributors; oil and gas on tribal lands is included in the state contributions (see Table 3 in Section 3 of the TSS Emissions Reference document for breakdown of tribal vs non-tribal NOx emissions.) EGU and mobile source sectors are also contributors to AmmNO3. EGU from non-WRAP states and oil and gas in NM are the largest contributors to AmmSO4 at MEVE1. Weighted Emissions Potential plots for MEVE1 confirm the Four Corners region and Arizona as the highest transport area for AmmNO3 and that EGU in Texas contribute to AmmSO4 loadings.

In general, at western Class I areas mobile emissions and oil and gas emissions are significant contributors to AmmNO3, while electric generating units and remaining point sources are more important source categories for AmmSO4.

12.0 Weighted Emissions Potential

WRAP 2028 Weighted Emissions Potential maps were developed to illustrate the geographic areas of greatest emissions influence for aerosol extinction on most impaired days at 76 IMPROVE monitors representing 116 Class I areas in the 13 WESTAR-WRAP states and neighboring states. 72-hour back trajectory analyses (defined every 6 hours for multiple start heights) for most impaired days for the 5-year period 2014-2018 were used to define frequency of atmospheric transport. Gridded 2028 modeled emissions in 36-km grid cells, residence time defined by back trajectory transport frequency, residence time weighted aerosol extinction for most impaired days (also called area of influence), and weighted emission potential for gridded emissions can be downloaded from the Weighted Emissions Potential webpage. The weighted emissions potential defines relative source importance for each Class I area. These analyses provide weight of evidence in support of state and sector source apportionment results in Section 11.0.

Figure 17a (left) displays the areas of highest influence from NOx emissions, weighted by AmmNO3 extinction on the most impaired days for YELL2, highlighted in burgundy and orange elliptical shapes overlaying eastern Idaho and western Wyoming. **Figure 17a (right)** displays the individual 36-km model grid cells, color graded by importance of mobile source NOx emissions for AmmNO3 extinction on most impaired days at YELL2 (burgundy, orange, and green grid cells have the highest importance). **Figure 17b (left)** displays areas of highest influence from SO2 emissions, weighted by AmmSO4 extinction on the most impaired days for YELL2.

Interpretation: The Weighted Emissions Potential maps agree with the PSAT results (Section 11.0) for YELL2 and MEVE1. For YELL2 the geographic area of influence is similar for AmmNO3 and AmmSO4 extinction (**Figures 17a, left and 17b, left**.) For mobile sources, the highest contributors to AmmNO3 extinction on most impaired days at YELL2 include the mobile source corridors in Idaho and grid cells in Montana, Utah, Oregon and Washington (**Figure 17a, right**). Non-Electric generating point sources (non-EGU) in several states are seen as important

contributors to AmmSO4 extinction on most impaired days at YELL2 (**Figure 17b right**). These results agree with PSAT results that identify mobile sources as largest contributors to AmmNO3 (**Figure 16a**) and non-EGU point sources as largest contributors to AmmSO4 extinction at YELL2 (**Figure 16b**).

Figure 17a. 2028OTBa2 Extinction Weighted Residence Time for Ammonium Nitrate (AmmNO3) Light Extinction (Mm^{-1}) (left) and NOx Weighted Emissions Potential for On-Road Mobile sources (right) for most impaired days at the Yellowstone National Park (YELL2) IMPROVE monitor. Weighted Emissions Potential

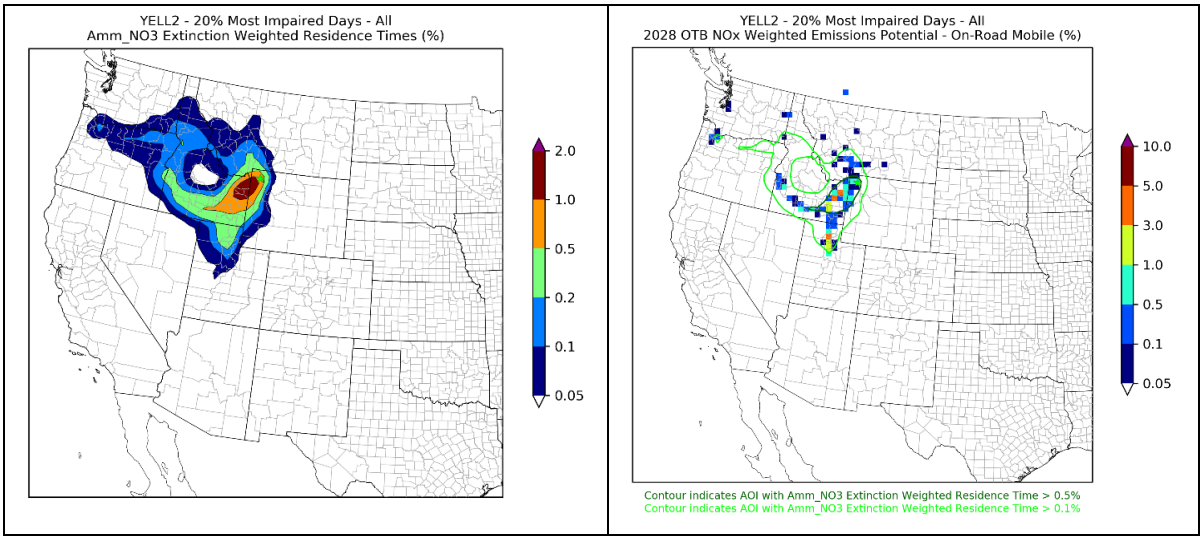
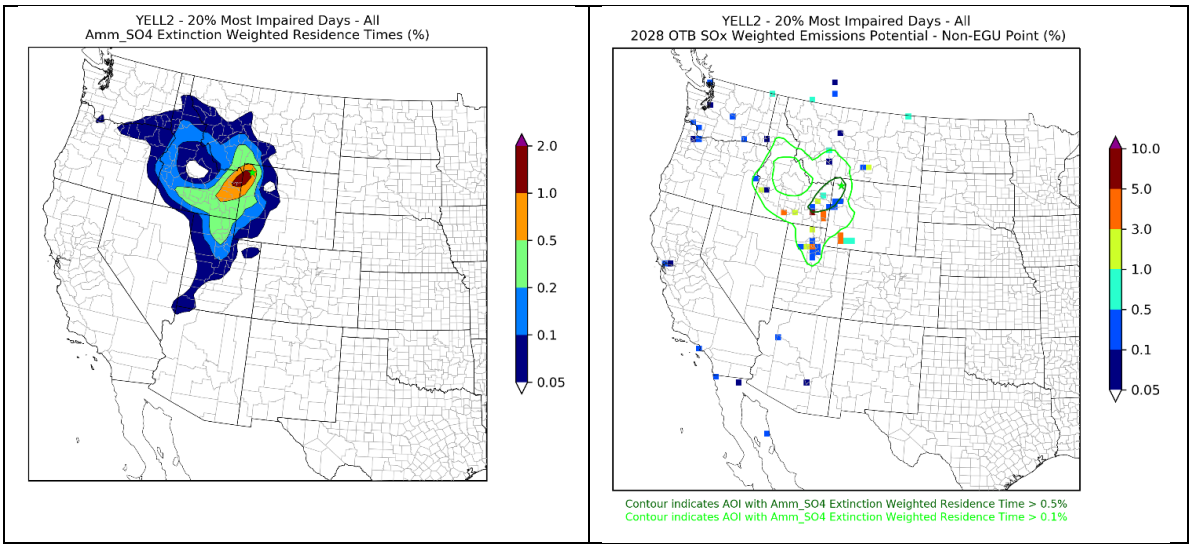


Figure 17b. 2028OTBa2 Extinction Weighted Residence Time for Ammonium Sulfate (AmmSO4) Light Extinction (Mm^{-1}) (left) and SO2 Weighted Emissions Potential for Non-Electric Generating Point sources (right) for most impaired days at the Yellowstone National Park (YELL2) IMPROVE monitor. Weighted Emissions Potential



For MEVE1, **Figure 17c, left** display the geographic areas of highest influence for NOx emissions, weighted by AmmNO3 extinction on the most impaired days. In **Figure 17c, right** the areas of highest influence are outlined in dark green and light green boundaries and oil and gas point and area sources contributions to AmmNO3 are defined in color-graded 36-km grid cells. **Figure 17d, left** displays a very similar geographic area of influence for SO2 emissions, weighted by AmmSO4 extinction on most impaired days. **Figure 17d, right** illustrates that electric generating units that influence AmmSO4 extinction at MEVE1 on most impaired days are geographically dispersed and not restricted to the geographic area of highest influence for total AmmSO4.

Figure 17c. 2028OTBa2 Extinction Weighted Residence Time for Ammonium Nitrate (AmmNO3) Light Extinction (Mm^{-1}) (left) and NOx Weighted Emissions Potential for On-Road Mobile sources (right) for most impaired days at the Mesa Verde National Park (MEVE1) IMPROVE monitor. Weighted Emissions Potential

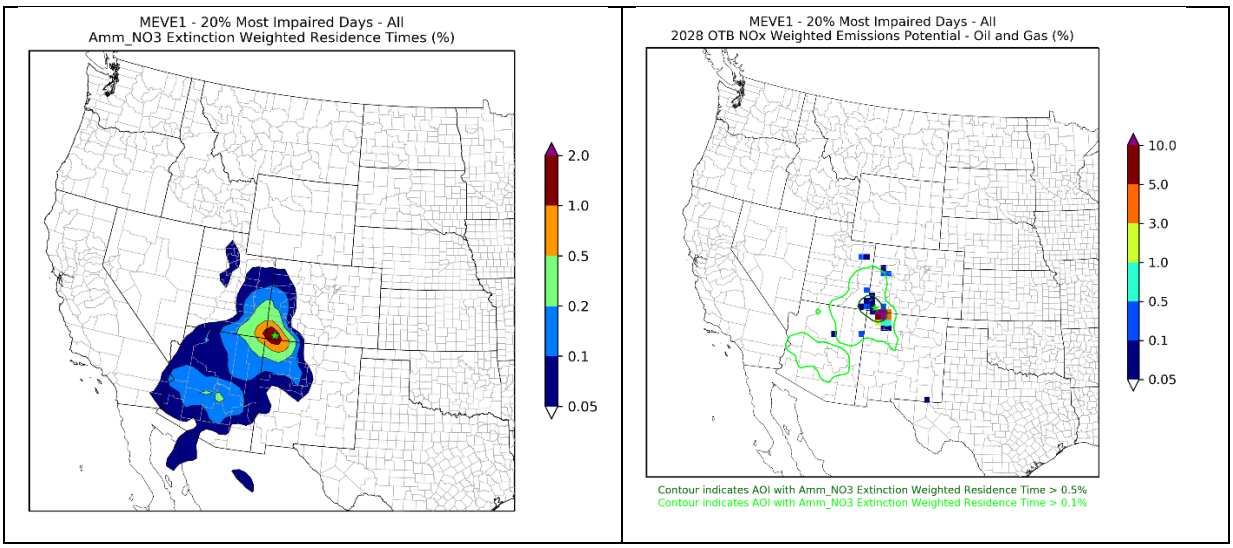
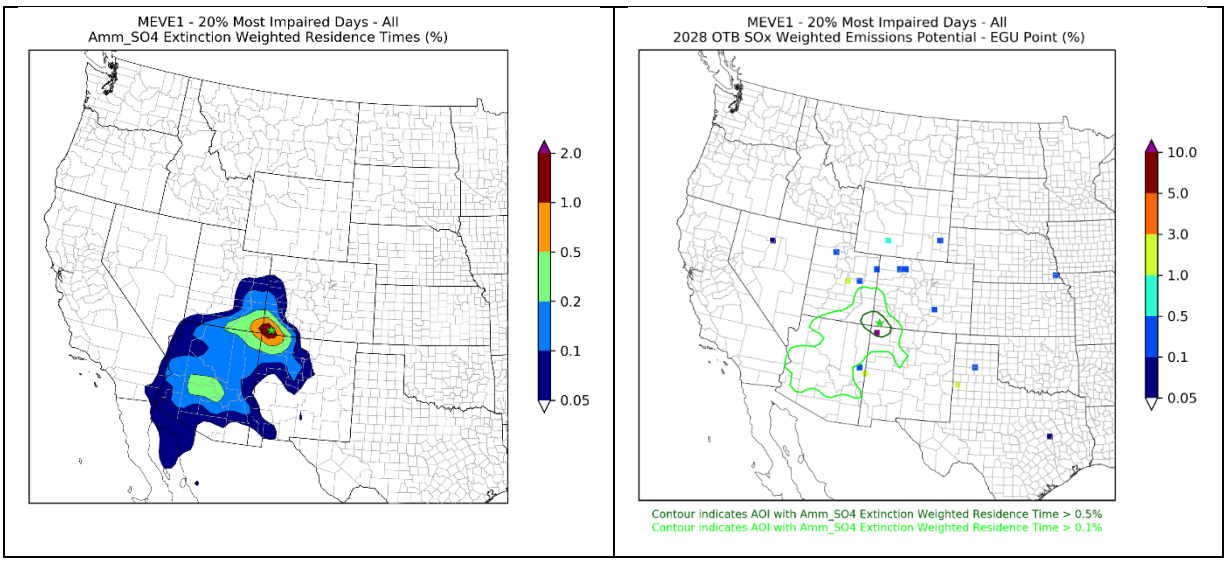


Figure 17d. 2028OTBa2 Extinction Weighted Residence Time for Ammonium Sulfate (AmmSO4) light Extinction (Mm^{-1}) (left) and SO2 Weighted Emissions Potential for Electric Generating Units (EGU) sources (right) for most impaired days at the Mesa Verde National Park (MEVE1) IMPROVE monitor. Weighted Emissions Potential



The area of greatest influence for AmmNO3 extinction on most impaired days at MEVE1 (**Figure 17c, left)** is centered over the Four Corners area. In **Figure 17c, right** the area of greatest influence is outlined in the dark green elliptical boundary over the Four Corners and the lighter green boundary over portions of the four states: AZ, CO, NM, and UT. On the same plot, the 36-km grid cells are color coded by importance of NOx emissions from oil and gas area and point sources. The oil and gas contributions are primarily located within the inner dark green area of influence.

The areas of greatest influence for AmmSO4 extinction on most impaired days at MEVE1 are illustrated in **Figure 17d, left** and **17d, right.** The areas of influence are similar to those for AmmNO3 extinction at MEVE1. The EGU plot illustrates emissions from elevated EGU point sources can influence visibility at a distant Class I area even if transport from the EGU point source is infrequent. These maps are consistent with the PSAT state and sector source apportionment for AmmNO3 and AmmSO4 at MEVE1 (Section 11.0)

13.0 Dynamic Model Evaluation

As part of the WRAP-WAQS 2014 modeling study, a dynamic model evaluation was conducted to test the model's ability to project changes in ambient aerosol visibility extinction at IMPROVE monitoring sites in response to changes in U.S. anthropogenic emissions. To conduct the dynamic model evaluation, in addition to the 2014v2, RepBase2 and 2028OTBa2 model

scenarios already discussed, an additional scenario representing U.S. anthropogenic emissions for 2002 (2002 Hindcast) was run using the CAMx-PSAT photochemical grid model platform with 2014 meteorology and RepBase2 emissions for all other natural, fire, and international source groups. Only U.S. anthropogenic emissions changed between the 2002 Hindcast, RepBase2, and 2028OTBa2 model scenarios. 2002 U.S. Anthropogenic emissions were back cast from the 2014 National Emissions Inventory (NEI) using scaling factors based on EPA's NEI trends for most sectors, with exceptions that California Air Resources Board provided 2014 to 2002 scaling factors for California, and western states supplied 2002 emissions for point sources (electric generating units (EGU), oil and gas point sources, and other non-EGU point sources.) Methods for the 2002 Hindcast are further defined in the U.S. Anthropogenic Emissions Rate of Progress document (September 2021).

The dynamic model evaluation applied the same future year projection methods defined by Environmental Protection Agency modeling guidance (December 2018) to project 2014-2018 visibility from the 2002 Hindcast forward to the RepBase2 scenario. Relative response factors for each aerosol species were calculated (RepBase2 model results divided by 2002 Hindcast model results) and then multiplied by 2000-2004 IMPROVE observations for each species to project RepBase2 visibility. Model projected RepBase2 aerosol light extinction closely matched IMPROVE observed light extinction for 2014-2018 5-year average (**Figure 18a**). This confirmation increases confidence that the CAMx model and EPA projection methods can produce credible 2028 visibility projections. Backward projections of 2002 visibility from RepBase2 (relative response factors calculated as 2002 Hindcast divided by RepBase2 and then multiplied by 2014-2018 IMPROVE observations) had larger discrepancies from 2000-2004 IMPROVE observations than forward projections from 2002 to RepBase2, but still showed good agreed for most western IMPROVE sites (**Figure 18b**). The larger discrepancies for the 2002 Hindcast are likely due to a combination of (i) using RepBase2 levels of fire and international emissions for the 2002 Hindcast model run that differed from the actual emissions that contributed to 2000-2004 IMPROVE observations and (ii) using scaling factors to calculate 2002 Hindcast emissions from 2014v2 National Emissions Inventory that introduces errors for U.S. anthropogenic emissions (e.g., over estimating 2002 emissions for Commercial Marine Vessel emissions). A future dynamic model evaluation may want to back cast natural, fire and international emissions as well as U.S. anthropogenic emissions.

Figure 18a. Dynamic Model Evaluation applying EPA projection methods and comparing total aerosol light extinction for 2014-2018 IMPROVE observations (x-axis) to modeled RepBase2 (y-axis) for Class I areas in the 13 western states. U.S. Anthropogenic Emissions Rate of Progress

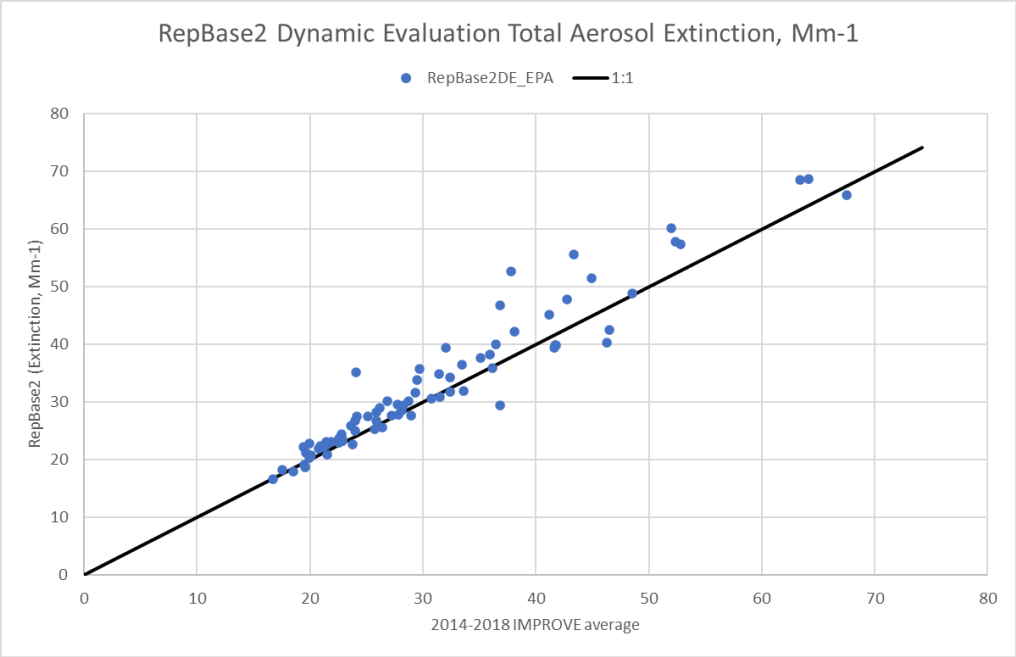
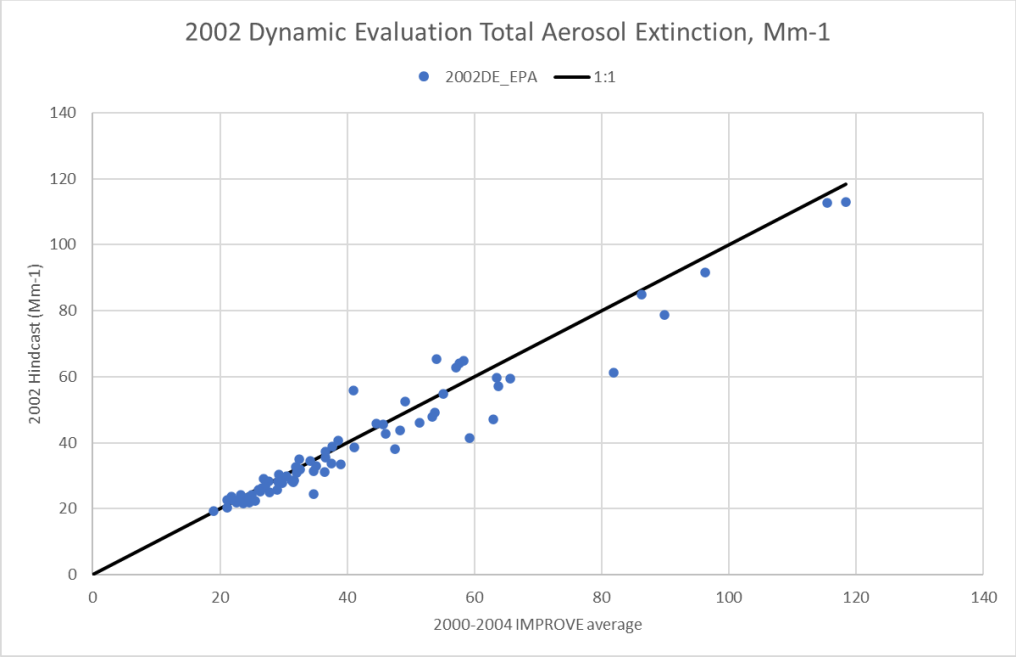


Figure 18b. Dynamic Model Evaluation applying EPA projection methods and comparing total aerosol light extinction for 2000-2004 IMPROVE observations (x-axis) to modeled 2002 Hindcast (y-axis) for Class I areas in the 13 western states. U.S. Anthropogenic Emissions Rate of Progress



14.0 U.S. Anthropogenic Emissions Rate of Progress

WRAP has defined a U.S. Anthropogenic Emissions Rate of Progress to demonstrate visibility progress at western Class I areas due to changes in U.S. Anthropogenic emissions between the 2002 Hindcast, RepBase2, and 2028OTBa2 model scenarios. Methods for the 2002 Hindcast, RepBase2 and 2028OTBa2 scenario development are further defined in the WRAP-WAQS run specification sheets

- Representative Baseline v2 and 2028OTBa2
- U.S. Anthropogenic Emissions Rate of Progress

The URP glidepath represents total haze from all source contributions on most impaired days. In the western U.S., haze is caused by international, natural, and fire emissions as well as U.S. anthropogenic emissions. Uncertainties in the URP glidepath construction are further described in the U.S. Anthropogenic Emissions Rate of Progress webpage.

The objective of the U.S. Anthropogenic Emissions Rate of Progress is to isolate the contributions of U.S. anthropogenic emissions to visibility at Class I areas in the WESTAR-WRAP states and to demonstrate the progress in improving visibility in response to changes in U.S. anthropogenic emissions between the 2002 Hindcast, RepBase2, and 2028OTBa2 scenarios.

- Only U.S. anthropogenic emissions change in the three model scenarios.
    - Any differences in aerosol extinction between the 2002, RepBase2, and 2028OTBa2 scenarios are due to changes in U.S. anthropogenic emissions.
    - We have greatest confidence in U.S. anthropogenic emissions.

- All other emissions (natural, fire, and international) are held constant at RepBase2 levels for the 2002 Hindcast and 2028OTBa2 scenarios.
    - Because RepBase2 international, fire, and natural emissions are used in the 2002 Hindcast scenario, the 2002 Hindcast results are not fully comparable to the 2000-2004 IMPROVE monitoring data.

- The source apportionment model results are not adjusted to the IMPROVE monitoring data.

- The U.S. Anthropogenic Emissions Rate of Progress is intended as an alternative to adjusting the 2064 endpoint of the URP glidepath using 2028 source apportionment results for international and U.S. wildland prescribed fire, per EPA guidance.

TSS Modeling Express Tool # 6, illustrated in **Figures 19a and 19b** displays US Anthropogenic, International Anthropogenic, Natural, Fire, and Rayleigh contributions to total light extinction for the 2002 Hindcast, RepBase2, and 2028OTBa2 model scenarios for the IMPROVE monitors at Yellowstone (YELL2) and Mesa Verde (MEVE1) National Parks, respectively.

Interpretation: at YELL2 U.S. Anthropogenic contributions are projected to be reduced by 2 Mm^{-1} (39%) between 2002 Hindcast and RepBase2 and by 1 Mm^{-1} (30%) between RepBase2 and 2028OTBa2. This rate of progress is below the straight line drawn from 2002 U.S. anthropogenic contribution to zero U.S. anthropogenic contribution in 2064. This is in contrast to conclusions following EPA guidance, where 2028OTBa2 visibility projections for YELL2 are not below the URP glidepath (Section 8.0). The modeled rate of U.S. anthropogenic progress is below the glidepath to no U.S. anthropogenic contribution.

At MEVE1, U.S. anthropogenic contributions are projected to be reduced by 3 Mm^{-1} (41%) between 2002 Hindcast and RepBase2 and by 0.8 Mm^{-1} (18%) between RepBase2 and 2028OTBa2. This rate of progress is below the straight line drawn from 2002 U.S. anthropogenic contribution to zero U.S. anthropogenic contribution in 2064.

Figure 19a. Contributions to Aerosol Light Extinction from U.S. Anthropogenic, International Anthropogenic, Natural, and Fire emissions, plus Rayleigh light scattering, for the 2002 Hindcast, RepBase2, and 2028OTBa2 model scenarios for most impaired days at Yellowstone National Park (YELL2) IMPROVE monitor. TSS Modeling Express Tool # 6

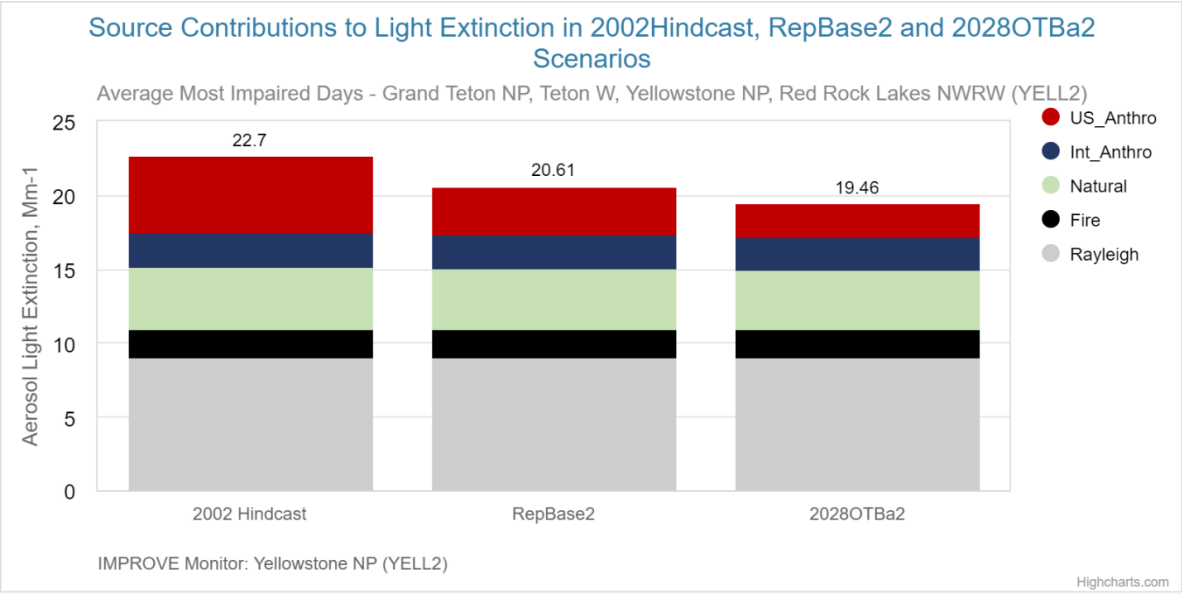
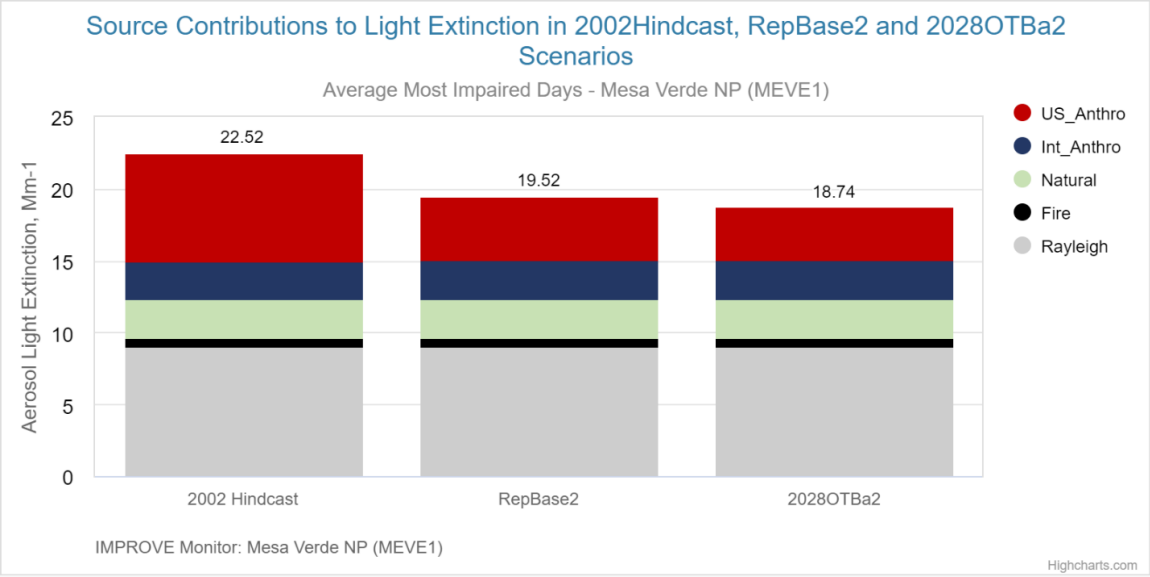


Figure 19b. Contributions to Aerosol Light Extinction from U.S. Anthropogenic, International Anthropogenic, Natural, and Fire emissions, plus Rayleigh light scattering, for the 2002 Hindcast, RepBase2, and 2028OTBa2 model scenarios for most impaired days at Mesa Verde National Park (MEVE1) IMPROVE monitor. TSS Modeling Express Tool # 6



TSS Modeling Express Tool # 7, illustrated in **Figures 20a and 20b** displays aerosol species contributions to just the U.S. Anthropogenic fraction of total light extinction for the 2002 Hindcast, RepBase2 and 2028OTBa2 model scenarios for the IMPROVE monitors at Yellowstone (YELL2) and Mesa Verde (MEVE1) National Parks, respectively.

- TSS Chart 7 does not address aerosol light extinction from sources other than U.S. Anthropogenic contributions.
- The source apportionment model results are not adjusted to the IMPROVE monitoring data.

Interpretation: at both YELL2 and MEVE1, reductions in U.S. anthropogenic contributions between 2002 Hindcast and RepBase2 are primarily due to reductions in AmmSO4 and OMC. At YELL2, reductions projected to occur between RepBase2 and 2028OTBa2 are primarily due to reductions in AmmNO3. At MEVE1, reductions in U.S. anthropogenic contributions between RepBase2 and 2028OTBa2 are projected due to small reductions in AmmNO3 and AmmSO4.

Figure 20a. U.S. Anthropogenic Contributions to Speciated Aerosol Light Extinction for the 2002 Hindcast, RepBase2, and 2028OTBa2 model scenarios for most impaired days at Yellowstone National Park (YELL2) IMPROVE monitor. TSS Modeling Express Tool # 7

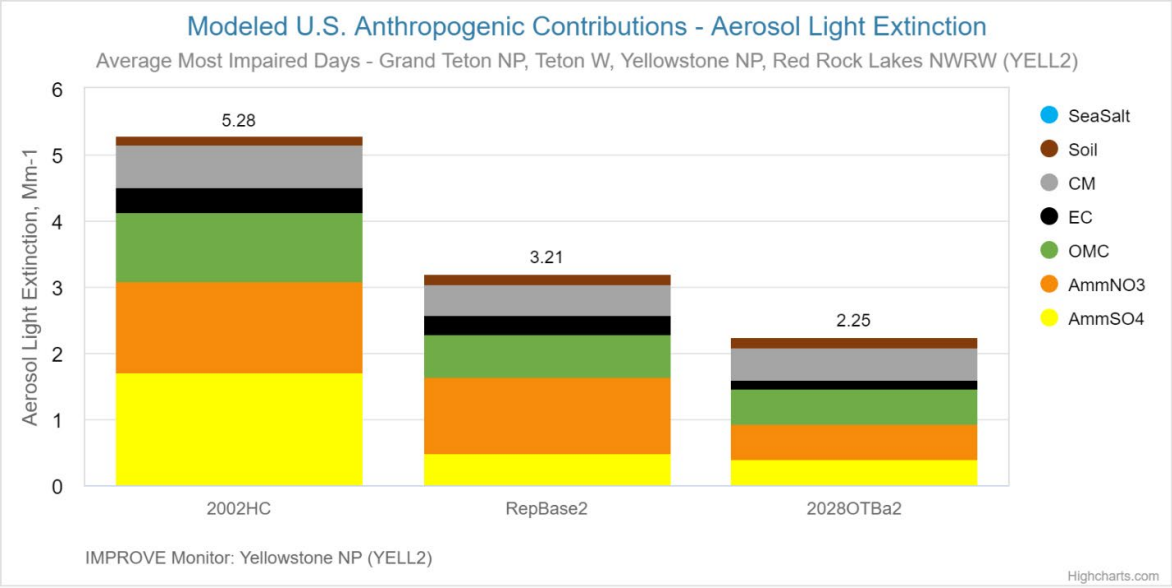
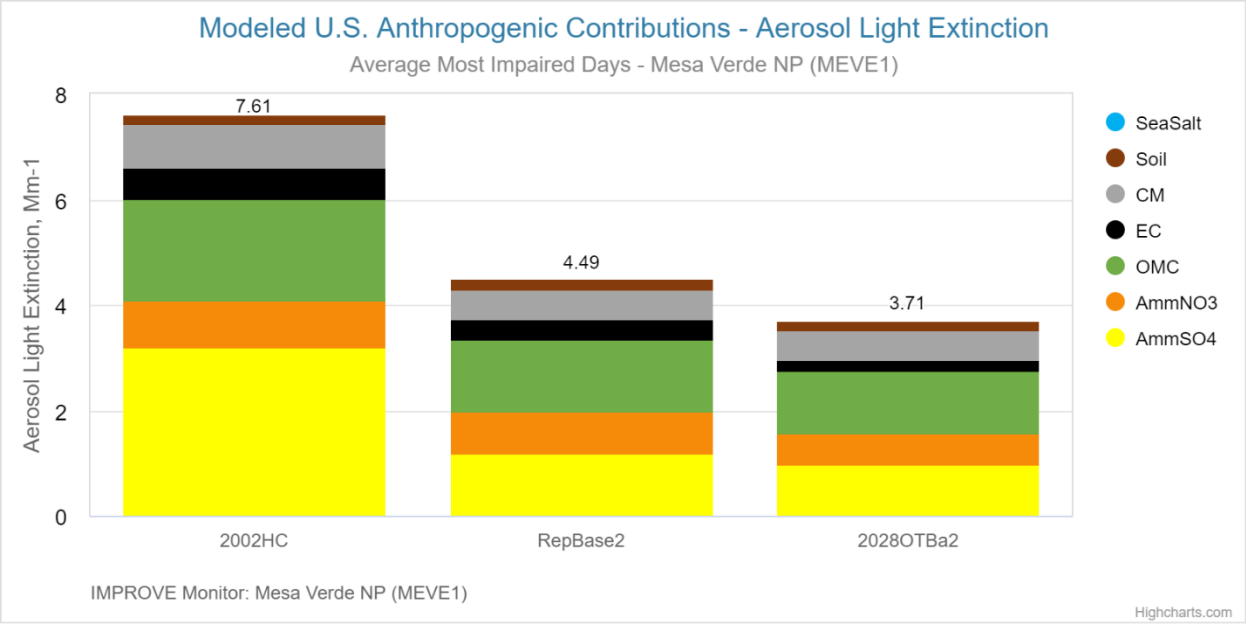


Figure 20b. 2028 U.S. Anthropogenic Contributions to Speciated Aerosol Light Extinction for the 2002 Hindcast, RepBase2, and 2028OTBa2 model scenarios for most impaired days at Mesa Verde National Park (MEVE1) IMPROVE monitor. TSS Modeling Express Tool # 7



15.0 Future Fire Sensitivities

Future fire sensitivities added wildfire emissions (FFS1) or wildland prescribed fire emissions (FFS2) as two potential future variations in fire activity that are not specific to any single future year. The fire sensitivities are added to the 2028OTBa2 reference case scenario to replace historic fire emissions used in the RepBase2 and 2028OTBa2 scenarios. All other 2028OTBa2 emissions: U.S. anthropogenic, international, natural, and non-US fire emissions are held constant. The only differences between the 2028OTBa2 and the fire sensitivities are due to the FFS1 and FFS2 assumptions.

- **FFS1** examines the effects of potential future changes in the timing, frequency, and intensity in terms of acres burned for **wildfires** compared to the Representative Baseline fires.
- **FFS2** examines the effects of potential future enhanced forest management practices defined as increases in **wildland prescribed burns**.

Emissions development of the future fire sensitivities is described in the Air Sciences, Inc. report Fire Emissions Inventories for Regional Haze Planning: Methods and Results (April 2020).

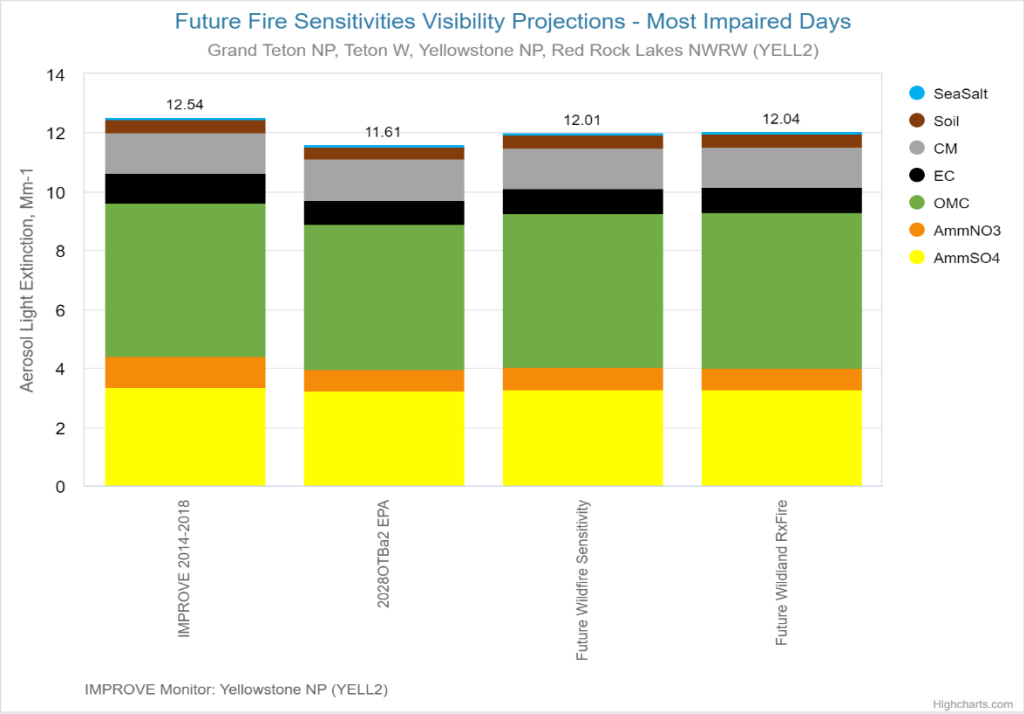
Modeling procedures are detailed in the run specification sheet for the Future Fire Simulations (August 2021).

TSS Modeling Express Tool # 18, illustrated in **Figures 21a and 21b**, displays IMPROVE 2014-2018 aerosol light extinction (Mm^{-1}) compared to the 2028 visibility projections for the 2028OTBa2, Future Wildfire Sensitivity, and Future Wildland Prescribed Fire Sensitivity scenarios for the IMPROVE monitors at Yellowstone (YELL2) and Mesa Verde (MEVE1) National Parks, respectively.

In TSS Modeling Express Tool # 18, fire sensitivities have been processed through the EPA Software for Modeled Attainment Test (normalized to IMPROVE 2014-2018 observations) to test the impact of changing fire regimes on 2028 regional haze visibility projections. The fire sensitivities for wildfire and wildland prescribed fire are compared to the 2028OTBa2 visibility projections for most impaired days or clearest days.

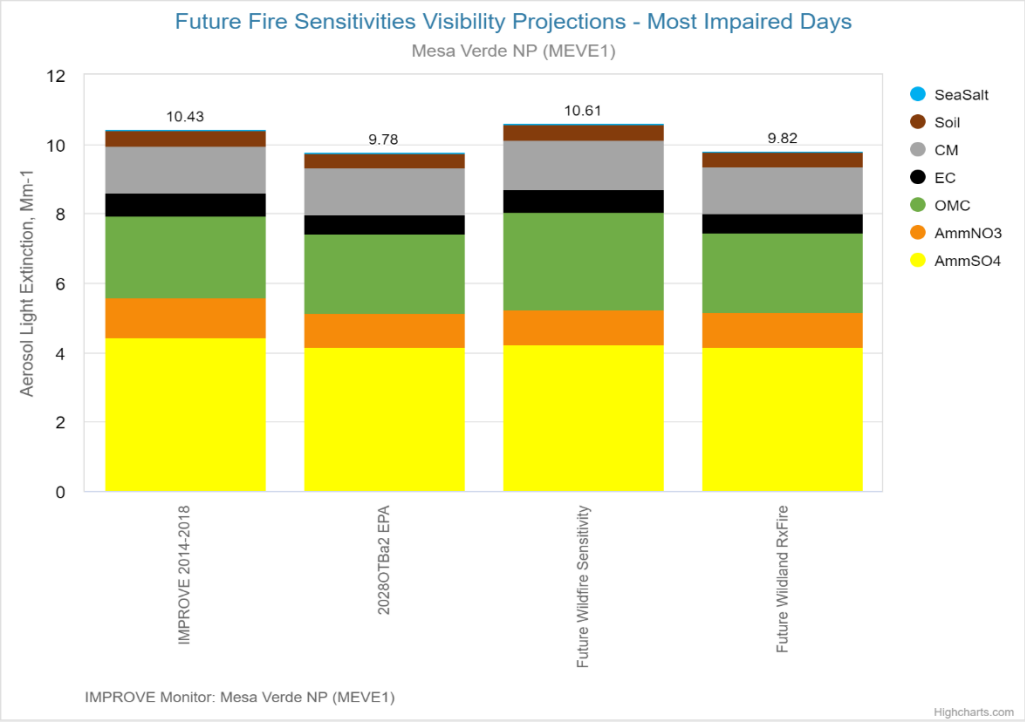
Interpretation: Added fire activity does not necessarily occur on 2014 IMPROVE most impaired days. The impacts of changing fire activity on the regional haze metrics are site-specific and may be small. IMPROVE 2014-2018 observations are included in TSS Modeling Express Tool #18 as the baseline data used with the relative response factors to calculate the 2028 visibility projections. At YELL2 (**Figure 21a)**, the 2028OTBa2 visibility projection shows small decreases in AmmNO3, OMC, and EC compared to 2014-2018 observations. The Future Wildfire Sensitivity and the Future Wildland Prescribed fire sensitivity show minor increases in OMC that can be attributed to changes in fire activity on some most impaired days in these sensitivities.

Figure 21a. IMPROVE 2014-2018 aerosol light extinction (Mm^{-1}) compared to the 2028 visibility projections (following EPA guidance) for the 2028OTBa2, Future Wildfire Sensitivity, and Future Wildland Prescribed Fire Sensitivity scenarios for most impaired days at the Yellowstone National Park (YELL2) IMPROVE monitor. TSS Modeling Express Tool # 18



At MEVE1 (**Figure 21b**), OMC is a smaller contributor on most impaired days than at YELL2. 2028OTBa2 visibility projection shows small decreases in AmmSO4 and AmmNO3 compared to the 2014-2018 IMPROVE observations. OMC increases in the Future Wildfire sensitivity indicating increased fire emissions on some most impaired days for this sensitivity. OMC is little changed in the Future Wildland Prescribed fire sensitivity compared to 2028OTBa2.

Figure 21b. IMPROVE 2014-2018 aerosol light extinction (Mm^{-1}) compared to the 2028 visibility projections (following EPA guidance) for the 2028OTBa2, Future Wildfire Sensitivity, and Future Wildland Prescribed Fire Sensitivity scenarios for most impaired days at the Mesa Verde National Park (MEVE1) IMPROVE monitor. TSS Modeling Express Tool # 18



TSS Modeling Express Tool # 19, illustrated in **Figures 22a and 22b**, displays absolute model results (not adjusted to IMPROVE observations) for 2028OTBa2 and the future fire sensitivities as monthly averages for all IMPROVE sample collection days. This chart illustrates when changes in wildfire or wildland prescribed fire activity are projected to occur and how the changes affect visibility compared to the 2028OTBa2 fire assumptions. These results are not 2028 visibility projections (adjusted to IMPROVE data) for regional haze planning purposes.

Interpretation: at YELL2 (**Figure 22a**) in several months there are small differences in AmmSO4, AmmNO3, and OMC between the 2028OTBa2 scenario and the Future Fire Sensitivities. The Future Wildfire Sensitivity is higher than 2028OTBa2 in July, September and October, while the Future Wildland Prescribed Fire Sensitivity is higher in January, February, April, May, October, and November. Not all the fire activity changes occurred on most impaired days so the impacts on the 2028 visibility projections are small.

Figure 22a. Monthly average aerosol extinction (Mm^{-1}) for the 2028OTBa2, Future Wildfire Sensitivity, and Future Wildland Prescribed Fire Sensitivity scenarios for most impaired days at the Yellowstone National Park (YELL2) IMPROVE monitor. TSS Modeling Express Tool # 19

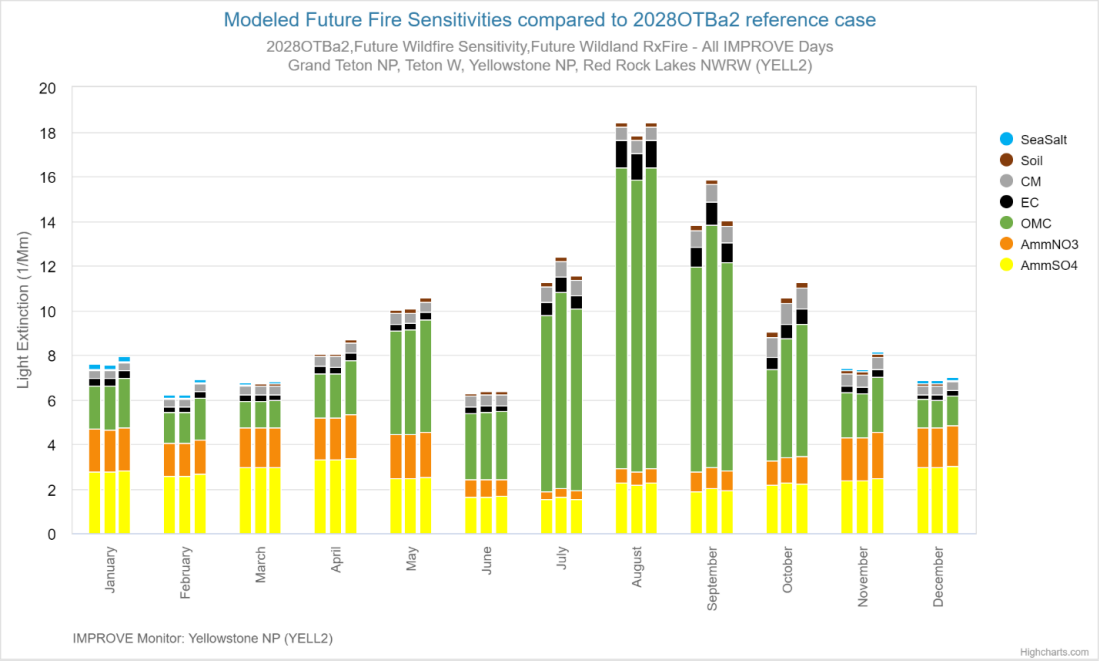
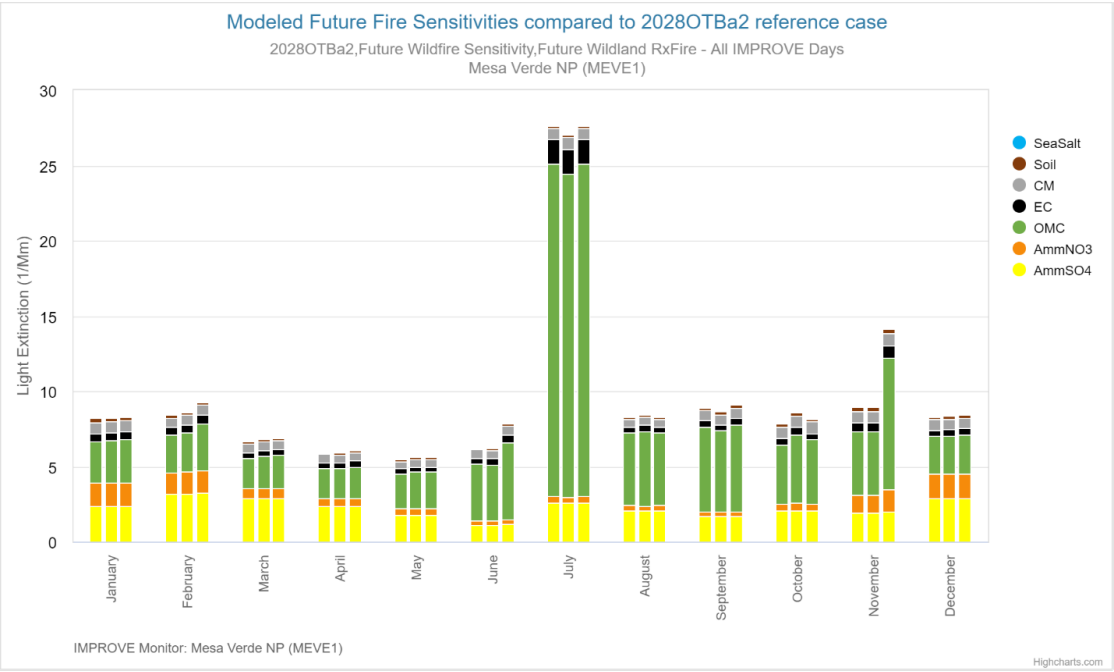


Figure 22b. Monthly average aerosol extinction (Mm^{-1}) for the 2028OTBa2, Future Wildfire Sensitivity, and Future Wildland Prescribed Fire Sensitivity scenarios for most impaired days at the Mesa Verde National Park (MEVE1) IMPROVE monitor. TSS Modeling Express Tool # 19

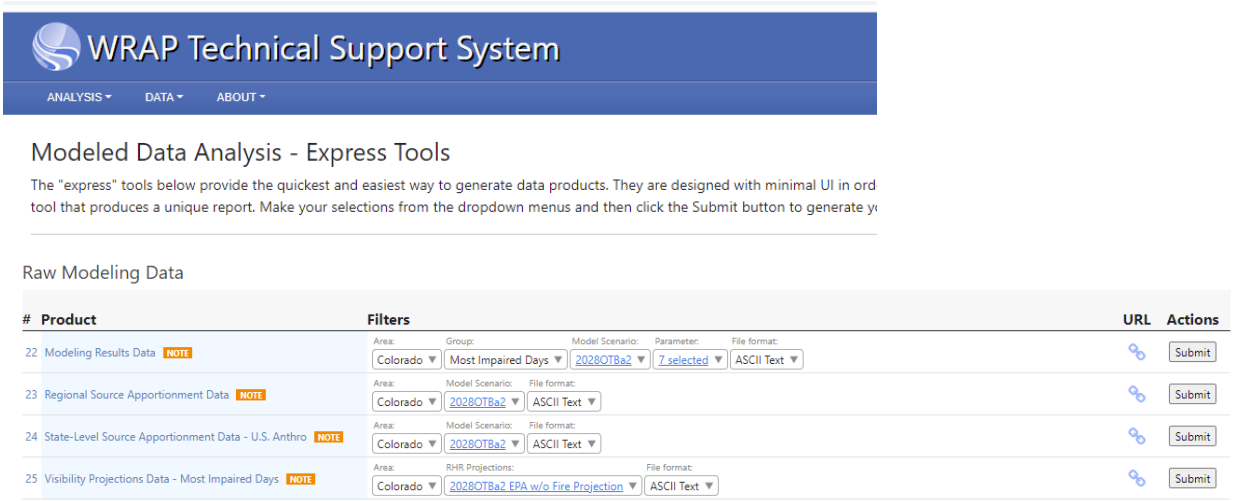


At MEVE1 (**Figure 22b**) the Future Wildfire Sensitivity shows very slight monthly differences compared to the 2028OTBa2 scenario, even though the Future Wildfire visibility projection has slightly higher OMC than the 2028OTBa2 projection (**Figure 21b**). This suggests that wildfire activity added on a few most impaired days was offset by decreased wildfire activity on other days in the monthly averages. The Future Wildland Prescribed Fire Sensitivity in June and November show slightly higher OMC than 2028OTBa2, but little change in the 2028 visibility projection.

At some western Class I areas, the added future fire sensitivities have larger impacts than seen as these two sites. Fires will continue to be a major contributor to haze in western states, however the regional haze tracking metric may not be the best measure of changes in future fire activity.

16.0 Modeling Data files

Raw modeling data files can be downloaded from the TSS Modeling Express Tools #22-25 as illustrated below. Data are sorted by geographic area, by IMPROVE data groups, Model scenarios, pollutant parameters, and regional haze projection methods. Data can be downloaded as ASCII text, Microsoft Excel, or JSON format.



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(no new citations in Sections 9.0-15.0)

Appendix C: Four-Factor Analyses and Control Measures Determinations Technical Support Document

C.1 Introduction

The Regional Haze Rule requires states to evaluate and determine the emission reduction measures that are necessary to make reasonable progress toward natural visibility conditions in Class I Areas in New Mexico, as well as in Class I Areas outside New Mexico that may be affected by emissions from New Mexico. In determining which measures are necessary to make reasonable progress, states are required to consider four statutory factors, including "the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source."[1] Hence, these evaluations are commonly referred to as four-factor analyses (FFA).

This Technical Support Document briefly describes NMED's process for selecting sources for an evaluation of potential control measures, identifies the different types of equipment evaluated and the controls available for each, and then provides detailed descriptions of NMED's four-factor analyses and control measures determinations for all selected sources. FFA supporting documentation is provided in Appendix D. Additional facility information, including printable facility reports and downloadable documents, is available via NMED's online Air Permit Map, available at https://rsmt.air.net.env.nm.gov/.

C.2 Screened Sources

The Regional Haze Rule requires that each state select emission sources for an analysis of what emission control measures are necessary to make reasonable progress. NMED utilized a two-tiered screening process to select sources for analysis in the second planning period. For tier one, NMED calculated Q/d scores for all Title V facilities in New Mexico (excluding sources on tribal lands) and compared them to a threshold value designed to capture 80 percent of the total NO_X and SO_2 emissions from all New Mexico Title V facilities combined. This resulted in the selection of 23 facilities within the jurisdiction of the Environmental Improvement Board (EIB) for further screening, including:

- Davis Gas Processing – Denton Gas Plant
- DCP Operating Company – Artesia Gas Plant
- DCP Operating Company – Eunice Gas Plant
- DCP Operating Company – Linam Ranch Gas Plant
- El Paso Natural Gas Company – Blanco Compressor Station A
- El Paso Natural Gas Company – Pecos River Compressor Station
- El Paso Natural Gas Company – Washington Ranch Storage Facility
- Enterprise Field Services – Blanco C&D Compressor Station
- Enterprise Field Services – Chaco Gas Plant
- Enterprise Field Services –South Carlsbad Compressor Station
- ET Gathering & Processing – Jal #3 Gas Plant
- Transwestern Pipeline Company – Mountainair Compressor Station No. 7
- Transwestern Pipeline Company – Roswell Compressor Station No. 9
- Harvest Four Corners – Kutz Canyon Processing Plant
- Hilcorp Energy Company – San Juan Basin Gas Plant
- IACX Roswell – Bitter Lake Compressor Station

[1] 40 CFR 305(f)(2)(i).

- Oxy USA WTP Limited Partnership – Indian Basin Gas Plant
- Public Service Company of New Mexico – San Juan Generating Station
- Targa Midstream Services – Eunice Gas Processing Plant
- Targa Midstream Services – Monument Gas Plant
- Targa Midstream Services – Saunders Gas Plant
- Tri-State Generation and Transmission Association – Prewitt Escalante Generating Station
- Xcel Energy – Cunningham Station Power Plant

For tier two, NMED identified all emissions units at these facilities with the potential to emit more than 10 pounds per hour of NO_X or SO_2. Due to resource constraints, NMED decided to focus on these units, as they are the most significant sources of NO_X and SO_2 at the selected facilities.[2] This resulted in the selection of approximately 122 units for an analysis of what emission control measures are necessary in order to make reasonable progress. NMED also elected to evaluate the amine treatment systems (ATS) at 11 facilities due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams.

After NMED completed its source screening, four of the selected facilities permanently shut down and have since been or are in the process of being decommissioned and/or demolished. These include Davis Gas Processing's Denton Gas Plant, DCP Operating Company's Eunice Gas Plant, Public Service Company of New Mexico's San Juan Generating Station, and Tri State Generation and Transmission Association's Prewitt Escalante Generating Station. Four additional facilities have since retired one or more emissions units NMED originally selected for analysis, including ET Gathering & Processing's Jal #3 Gas Plant, Harvest Four Corners' Kutz Canyon Processing Plant, and Targa Midstream Services' Eunice and Saunders Gas Plants. NMED has also identified a number of units that are already effectively controlled (for reasons other than retirement) or that do not require an analysis of potential control measures for other reasons. These shutdowns, retirements and exclusions reduced the number of units (including ATS) NMED analyzed from 133 to 91.

C.3 Equipment Types Evaluated and Available Controls

The units selected for analysis via the screening process described in Section C.2 comprise reciprocating internal combustion engines (RICE), including two-stroke lean burn (2SLB), four-stroke lean burn (4SLB), and four-stroke rich burn (4SRB) RICE; combustion turbines (CT); industrial and utility boilers; and amine treatment systems (ATS). Before performing a four-factor analysis for any of the selected units, NMED identified all commercially available controls for these types of sources, determined which controls are technically feasible, and assessed, in general terms, the expected control efficiency, compliance time, and energy and non-air quality impacts associated with each technically feasible control.

C.3.1 Two-Stroke Lean Burn Engines

NMED determined that the following controls for reducing NO_X emissions from natural gas-fired 2SLB RICE are commercially available.

[2] NMED exempted units exceeding the 10 pounds per hour threshold that are exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC, or that emit less than five tons per year of NOx or SO_2.

Good Combustion Practices

Good Combustion Practices (GCP) describes the optimal design and proper operation and maintenance (O&M) of an emissions unit. In the case of RICE, GCP typically involves maintenance with trained personnel and includes performing periodic tune-ups and conducting overhauls as appropriate and necessary. A tune-up generally involves conducting an evaluation of existing equipment to determine if any equipment needs to be cleaned, repaired, or replaced.

Optimal design and proper O&M of a RICE maximizes fuel efficiency, minimizes emissions, reduces costs, and improves safety – benefits desirable to owners of RICE. Thus, RICE manufacturers are highly incentivized to design highly optimized units, and owners of existing RICE understand the benefits of following proper O&M schedules and procedures.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- GCP is a technically feasible control option for reducing NO_X emissions from 2SLB RICE.
- The NO_X control efficiency associated with GCP varies significantly as it depends on the age and condition of the unit and what other controls (if any) have been installed.
- The compliance time for GCP is 0-1 years. If a facility does not already implement GCP, up to a year may be necessary to obtain O&M documentation and train personnel.
- There are no energy or non-air quality impacts associated with GCP.

Low-Emission Combustion

Low-Emission Combustion (LEC), aka Clean Burn Technology, refers to a combination of equipment and technologies that minimize the creation of NO_X through higher air-to-fuel ratios and improved engine efficiency. Retrofitting a RICE with LEC can involve one or more engine modifications depending on the target NO_X emissions rate. For example, an LEC retrofit may include (but is not limited to) fuel system enhancements, improved ignition, turbocharger addition, cooling system improvements, addition of an oxidation catalyst, cylinder upgrades, and control system augmentations. For this reason, LEC is sometimes referred to as “layered combustion.”

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- LEC is a technically feasible control option for reducing NO_X emissions from 2SLB RICE.
- The NO_X control efficiency associated with LEC varies significantly as it depends on the existing NO_X emission rate and the target (post-retrofit) emission rate. Manufacturers will typically provide a post-retrofit NO_X emissions warranty, which varies based on make, model, age, and other factors.
- The compliance time for LEC is generally 2-3 years. This does not account for any facility-specific challenges that would prolong implementation.
- An LEC retrofit on a natural gas-fired 2SLB RICE can increase fuel consumption by up to 5 percent which can result in an increase in CO emissions.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is a pollution control measure that uses a catalyst and a selective reactant to convert NO_X into molecular nitrogen and water vapor. Ammonia (NH_3), usually diluted with air or steam, is injected into the exhaust upstream of a catalyst bed. At the catalyst surface, NH_3 reacts with NO_X to form molecular nitrogen and water with the following basic reaction pathways:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$$

Typical SCR catalysts include metal oxides (titanium oxide and vanadium pentoxide), noble metals (combinations of platinum and rhodium), zeolites, and ceramics. The catalyst serves to lower the activation energy of these reactions, which allows them to occur at a lower temperature than the exhaust gas. While operating temperatures can range from 350°F to 1,100°F, most SCR systems are designed to operate at temperatures between 600°F and 750°F for conventional (vanadium- or titanium-based) catalysts, and between 470°F and 510°F for platinum-based catalysts.

Design and operation of SCR systems can be challenging as several factors can affect SCR performance and corresponding NO_X reduction efficiency. Residence time, space velocity and the degree of mixing are critical as the reactants must be sufficiently mixed to ensure contact. Ammonia/NO_X ratios must be closely maintained to prevent unreacted ammonia from passing directly through the system ("ammonia slip"), resulting in increased emissions of PM10. If the catalyst bed temperature is too low, the NO_X reduction reactions will not proceed. If the catalyst bed temperature is too high, ammonia will be oxidized to NO and greater NO_X will be emitted than if no controls were present. If excessive temperatures occur for prolonged periods, thermal degradation of the catalyst can occur, resulting in loss of catalyst activity. Catalyst deactivation or "poisoning" can occur when certain elements – such as sulfur, iron, nickel, chrome, calcium, and sodium – present in the exhaust stream react with a platinum catalyst to form compounds which are not catalytically active.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- SCR is not a technically feasible control option for 2SLB RICE due to a relatively high amount of lubricating oil leakage (i.e., carryover) into the exhaust. The oil quickly adheres to and poisons the SCR catalyst.

Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction (SNCR) systems reduce NO_X by injecting a reagent (ammonia or urea) into the high-temperature regions of the exhaust from a combustion unit where the reagent will selectively react with NO_X to produce nitrogen and water. When urea is used as the reagent, it rapidly decomposes – due to the high temperature – to form ammonia before reacting with NO_X in the exhaust stream. While SNCR systems have been predominantly utilized on large industrial and utility-sized boilers, the technology has also been installed on a wide range of other combustion units including solid waste combustors, kilns and furnaces.

Effective design and operation of a SNCR system must carefully account for operating temperature, adequate exhaust/reagent mixing, sufficient residence time (i.e., greater than 0.5 seconds) and pollutant loading. Most notably, the technical feasibility of SNCR is extremely dependent on exhaust temperature, with an effective temperature range of approximately 1,600°F to 2,100°F. If the operating temperature is too low, the NO_X reduction reaction will not occur resulting in unreacted ammonia passing directly through the system ("ammonia slip"), causing increased particulate emissions. If the operating temperature is too high, ammonia will be oxidized to NO and greater NO_X will be emitted than if no controls were present. In addition, proper chemical storage and handling facilities must be built and operated to safely accommodate either reagent.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- SNCR is not a technically feasible control option for 2SLB RICE because the exhaust temperature is well below the effective temperature range.

Non-Selective Catalytic Reduction

Non-Selective Catalytic Reduction (NSCR) is a form of pollution control in which a precious metal catalyst (e.g., platinum) is used to promote reactions that reduce NO_X, CO, and hydrocarbon emissions by converting them into less harmful by-products (i.e., nitrogen, water and carbon dioxide). NSCR systems, also referred to as "three-way catalysts," are most commonly used to control tailpipe emissions in automobiles.

NSCR is most effective when the combustion unit is operated within a narrow band of near-stoichiometric fuel-to-air ratios, and conversion efficiency declines very rapidly when the unit is operated outside of that narrow band. Closed-loop control systems are necessary with NSCR because of the conflicting requirements for effective NO_X reduction and hydrocarbon oxidation. The control system must prevent the NO_X reduction catalyst from becoming fully oxidized, yet replenish the oxygen storage material to maintain its function as an oxidation catalyst.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- NSCR operating conditions limit its application to combustion processes with a fuel rich (no excess oxygen) firing zone, such as rich-burn RICE. Therefore, NSCR is not a technically feasible control option for 2SLB RICE.

Replacement with a New RICE

Current-generation RICE have significantly lower NO_X emissions rates than those manufactured 20 plus years ago. Many of the RICE subject to Regional Haze in New Mexico are more than 50 years old, and some are more than 70 years old. NMED and EPA agree that replacing an old RICE with a new, like-kind or functionally equivalent, more efficient, lower emitting RICE is within the scope of Regional Haze and thus an option states can consider when evaluating potential controls for 2SLB RICE.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- Replacement with a new RICE is a technically feasible control option for reducing NO_X emissions from 2SLB RICE.
- The NO_X control efficiency associated with RICE replacement varies significantly as it depends on the NO_X emission rate of the existing unit and that of the replacement unit. Consistent with the emission standards for new natural gas-fired RICE in 20.2.50 NMAC, the NO_X emission rate of a replacement RICE would typically be in the 0.3 to 0.5 g/bhp-hr range.
- NMED believes a reasonable compliance time for RICE replacement is 3-4 years. This estimate is based on the following timeframes for project development: 1-2 years for project approval, budgeting, and design; up to 1 year for equipment procurement; and up to 1 year for installation, commissioning, and start-up. This does not account for any facility-specific challenges that would prolong implementation.
- There are no appreciable energy or non-air quality impacts associated with RICE replacement. NMED understands that, in limited circumstances, the electricity demand of a facility could increase following RICE replacement.

Electrification

Natural gas compression technology has advanced significantly since many of the RICE subject to Regional Haze in New Mexico were installed. Several manufacturers now offer zero-emitting gas compression systems powered by electric motor drives (EMD). The use of EMD, commonly referred to as electrification, in the gas compression industry is becoming more prevalent as operators realize the lifecycle costs of EMD-powered systems can be considerably less than those of traditional systems powered by fossil fuel-fired RICE.

Based on a review of various information provided by EMD manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- Electrification is a technically feasible control option for reducing NO_X emissions from 2SLB RICE.
- The NO_X control efficiency associated with electrification is 100 percent. EMD do not emit NO_X or any other pollutants.
- NMED believes a reasonable compliance time for electrification is 4-6 years. This estimate is based on the following timeframes for project development: 1-2 years for project approval, budgeting, and design; up to 1 year for equipment procurement; up to 1 year for installation, commissioning, and start-up; and up to 2 years for the design and construction of associated electricity infrastructure (new distribution lines and substation upgrades). This does not account for any facility-specific challenges that would prolong implementation.
- Electrification, inherent to its design, significantly increases a facility's electricity demand.
- The economic feasibility of electrification at a particular facility is highly dependent on two factors, the availability of requisite utility-supplied electricity and the distance from the facility to the nearest electrical substation. If a facility does not have access to utility-supplied electricity or the facility's existing electricity infrastructure cannot support at least one EMD unit, the cost of electrification is significant. For example, the estimated cost of installing new distribution lines from a substation to a facility is typically more than $750,000 per mile (2024$).

Retirement

When a facility's operational plans can accommodate retiring an emissions unit, doing so is a simple and effective control option. Retirement, in this context, means permanently shutting down a unit and forgoing its capacity by not replacing it, which reduces emissions by 100 percent. Retirement is a technically feasible control option for any type of emissions unit, including 2SLB RICE. NMED believes a reasonable compliance time for retirement is 1-2 years depending on a facility's requisite planning time and operational flexibility. More time will be necessary when a facility needs a unit to satisfy anticipated near-term capacity requirements relative to a facility with excess capacity. There are no energy or non-air quality impacts associated with retirement.

C.3.2 Four-Stroke Lean Burn Engines

NMED determined that the following controls for reducing NO_X emissions from natural gas-fired 4SLB RICE are commercially available.

Good Combustion Practices

See Section C.3.1 for a description of this technology.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- GCP is a technically feasible control option for reducing NO_X emissions from 4SLB RICE.
- The NO_X control efficiency associated with GCP varies significantly as it depends on the age and condition of the unit and what other controls (if any) have been installed.
- The compliance time for GCP is 0-1 years. If a facility does not already implement GCP, up to a year may be necessary to obtain O&M documentation and train personnel.
- There are no energy or non-air quality impacts associated with GCP.

Low-Emission Combustion

See Section C.3.1 for a description of this technology.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- LEC is a technically feasible control option for reducing NO_X from 4SLB RICE.
- The NO_X control efficiency associated with LEC varies significantly as it depends on the existing NO_X emission rate and the target (post-retrofit) emission rate. Manufacturers will typically provide a post-retrofit NO_X emissions warranty, which varies based on make, model, age, and other factors.
- The compliance time for LEC is generally 2-3 years. This does not account for any facility-specific challenges that would prolong implementation.
- An LEC retrofit on a natural gas-fired 4SLB RICE can increase fuel consumption by up to 5 percent which can result in an increase in CO emissions.

Selective Catalytic Reduction

See Section C.3.1 for a description of this technology

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- By virtue of its design, lubricating oil does not leak into the exhaust of a 4SLB RICE. Therefore, SCR is a technically feasible control option for reducing NO_X emissions from 4SLB RICE.
- A well designed and operated SCR system can (in general) reduce NO_X emissions by more than 90 percent. However, for units that operate intermittently, such as natural gas compressor drivers, NO_X removal efficiency may be lower when the system is below the optimum temperature following cold starts. Depending on such a unit's annual operating profile, the average NO_X removal efficiency of SCR could reasonably vary from approximately 75 to 85 percent.
- Because SCR reactors can be fairly large, physical space limitations at existing facilities can necessitate significant modifications to a building's structure to accommodate SCR. The addition of SCR can also require considerable modifications to existing ductwork. Any such modifications are expected to appreciably increase the capital costs of implementing SCR.
- NMED believes a reasonable compliance time for SCR is 3-4 years. This estimate is based on the following timeframes for project development: 1-2 years for project approval, budgeting, and design; up to 1 year for equipment procurement; and up to 1 year for installation, commissioning, and start-up. This does not account for any facility-specific challenges that would prolong implementation.
- Operation of SCR on a 4SLB RICE would likely result in a small increase in fuel consumption as additional power would be needed to force exhaust through the catalyst bed. Additionally, electricity is needed to operate SCR.

Selective Non-Catalytic Reduction

See Section C.3.1 for a description of this technology.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- SNCR is not a technically feasible control option for 4SLB RICE because the exhaust temperature is well below the effective temperature range.

Non-Selective Catalytic Reduction

See Section C.3.1 for a description of this technology.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- NSCR operating conditions limit its application to combustion processes with a fuel rich (no excess oxygen) firing zone, such as rich-burn RICE. Therefore, NSCR is not a technically feasible control option for 4SLB RICE.

Replacement with a New RICE

Current-generation RICE have significantly lower NO_X emissions rates than those manufactured 20 plus years ago. Many of the RICE subject to Regional Haze in New Mexico are more than 50 years old, and some are more than 70 years old. NMED and EPA agree that replacing an old RICE with a new, like-kind or functionally equivalent, more efficient, lower emitting RICE is within the scope of Regional Haze and thus an option states can consider when evaluating potential controls for 4SLB RICE.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- Replacement with a new RICE is a technically feasible control option for reducing NO_X emissions from 4SLB RICE.
- The NO_X control efficiency associated with RICE replacement varies significantly as it depends on the NO_X emission rate of the existing unit and that of the replacement unit. Consistent with the emission standards for new natural gas-fired RICE in 20.2.50 NMAC, the NO_X emission rate of a replacement RICE would typically be in the 0.3 to 0.5 g/bhp-hr range.
- NMED believes a reasonable compliance time for RICE replacement is 3-4 years. This estimate is based on the following timeframes for project development: 1-2 years for project approval, budgeting, and design; up to 1 year for equipment procurement; and up to 1 year for installation, commissioning, and start-up. This does not account for any facility-specific challenges that would prolong implementation.
- There are no appreciable energy or non-air quality impacts associated with RICE replacement. NMED understands that, in limited circumstances, the electricity demand of a facility could increase following RICE replacement.

Electrification

Natural gas compression technology has advanced significantly since many of the RICE subject to Regional Haze in New Mexico were installed. Several manufacturers now offer zero-emitting gas compression systems powered by electric motor drives (EMD). The use of EMD, commonly referred to as electrification, in the gas compression industry is becoming more prevalent as operators realize the lifecycle costs of EMD-powered systems can be considerably less than those of traditional systems powered by fossil fuel-fired RICE.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- Electrification is a technically feasible control option for reducing NO_X emissions from 4SLB RICE.
- The NO_X control efficiency associated with electrification is 100 percent. EMD do not emit NO_X or any other pollutants.

- NMED believes a reasonable compliance time for electrification is 4-6 years. This estimate is based on the following timeframes for project development: 1-2 years for project approval, budgeting, and design; up to 1 year for equipment procurement; up to 1 year for installation, commissioning, and start-up; and up to 2 years for the design and construction of associated electricity infrastructure (new distribution lines and substation upgrades). This does not account for any facility-specific challenges that would prolong implementation.
- Electrification, inherent to its design, significantly increases a facility's electricity demand.
- The economic feasibility of electrification at a particular facility is highly dependent on two factors, the availability of requisite utility-supplied electricity and the distance from the facility to the nearest electrical substation. If a facility does not have access to utility-supplied electricity or the facility's existing electricity infrastructure cannot support at least one EMD unit, the cost of electrification is significant. For example, the estimated cost of installing new distribution lines from a substation to a facility is typically more than $750,000 per mile (2024$).

Retirement

When a facility's operational plans can accommodate retiring an emissions unit, doing so is a simple and effective control option. Retirement, in this context, means permanently shutting down a unit and forgoing its capacity by not replacing it, which reduces emissions by 100 percent. Retirement is a technically feasible control option for any type of emissions unit, including 4SLB RICE. NMED believes a reasonable compliance time for retirement is 1-2 years depending on a facility's requisite planning time and operational flexibility. More time will be necessary when a facility needs a unit to satisfy anticipated near-term capacity requirements relative to a facility with excess capacity. There are no energy or non-air quality impacts associated with retirement.

C.3.3 Four-Stroke Rich Burn Engines

NMED determined that the following controls for reducing NO_X emissions from natural gas-fired 4SRB RICE are commercially available.

Good Combustion Practices

See Section C.3.1 for a description of this technology.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- GCP is a technically feasible control option for reducing NO_X emissions from 4SRB RICE.
- The NO_X control efficiency associated with GCP varies significantly as it depends on the age and condition of the unit and what other controls (if any) have been installed.
- The compliance time for GCP is 0-1 years. If a facility does not already implement GCP, up to a year may be necessary to obtain O&M documentation and train personnel.
- There are no energy or non-air quality impacts associated with GCP.

Low-Emission Combustion

See Section C.3.1 for a description of this technology.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- LEC is a technically feasible control option for reducing NO_X emissions from 4SRB RICE.
- The NO_X control efficiency associated with LEC varies significantly as it depends on the existing NO_X emission rate and the target (post-retrofit) emission rate. Manufacturers will typically provide a post-retrofit NO_X emissions warranty, which varies based on make, model, age, and other factors.
- The compliance time for LEC is generally 2-3 years. This does not account for any facility-specific challenges that would prolong implementation.)
- An LEC retrofit on a natural gas-fired 4SRB RICE can increase fuel consumption by up to 5 percent which can result in an increase in CO emissions.

Selective Catalytic Reduction

See Section C.3.1 for a description of this technology.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- SCR is not a technically feasible control option for 4SRB RICE because SCR's NO_X conversion reactions will not occur in an environment with excess oxygen.

Selective Non-Catalytic Reduction

See Section C.3.1 for a description of this technology.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- SNCR is not a technically feasible control option for 4SRB RICE because the exhaust temperature is well below the effective temperature range.

Non-Selective Catalytic Reduction

See Section C.3.1 for a description of this technology.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- NSCR is an extremely well-established, cost-effective, and widely used control option for reducing NO_X emissions from 4SRB RICE.
- While NSCR can achieve NO_X reductions of greater than 90 percent on new 4SRB RICE, the NO_X control efficiency of a NSCR retrofit depends on the existing NO_X emission rate and the target (post-retrofit) emission rate.

- NMED believes a reasonable compliance time for NSCR is 3-4 years. This estimate is based on the following timeframes for project development: 1-2 years for project approval, budgeting, and design; up to 1 year for equipment procurement; and up to 1 year for installation, commissioning, and start-up. This does not account for any facility-specific challenges that would prolong implementation.
- A NSCR retrofit would likely result in a small increase in fuel consumption as additional power would be needed to force exhaust through the device. In addition, periodically replacing the catalyst would result in the disposal of old catalyst.

Replacement with a New RICE

Current-generation RICE have significantly lower NO_X emissions rates than those manufactured 20 plus years ago. Many of the RICE subject to Regional Haze in New Mexico are more than 50 years old, and some are more than 70 years old. NMED and EPA agree that replacing an old RICE with a new, like-kind or functionally equivalent, more efficient, lower emitting RICE is within the scope of Regional Haze and thus an option states can consider when evaluating potential controls for 4SRB RICE.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- Replacement with a new RICE is a technically feasible control option for reducing NO_X emissions from 4SRB RICE.
- The NO_X control efficiency associated with RICE replacement varies significantly as it depends on the NO_X emission rate of the existing unit and that of the replacement unit. Consistent with the emission standards for new natural gas-fired RICE in 20.2.50 NMAC, the NO_X emission rate of a replacement RICE would typically be in the 0.3 to 0.5 g/bhp-hr range.
- NMED believes a reasonable compliance time for RICE replacement is 3-4 years. This estimate is based on the following timeframes for project development: 1-2 years for project approval, budgeting, and design; up to 1 year for equipment procurement; and up to 1 year for installation, commissioning, and start-up. This does not account for any facility-specific challenges that would prolong implementation.
- There are no appreciable energy or non-air quality impacts associated with RICE replacement. NMED understands that, in limited circumstances, the electricity demand of a facility could increase following RICE replacement.

Electrification

Natural gas compression technology has advanced significantly since many of the RICE subject to Regional Haze in New Mexico were installed. Several manufacturers now offer zero-emitting gas compression systems powered by electric motor drives (EMD). The use of EMD, commonly referred to as electrification, in the gas compression industry is becoming more prevalent as operators realize the lifecycle costs of EMD-powered systems can be considerably less than those of traditional systems powered by fossil fuel-fired RICE.

Based on a review of various information provided by RICE manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- Electrification is a technically feasible control option for reducing NO_X emissions from 4SRB RICE.
- The NO_X control efficiency associated with electrification is 100 percent. EMD do not emit NO_X or any other pollutants.
- NMED believes a reasonable compliance time for electrification is 4-6 years. This estimate is based on the following timeframes for project development: 1-2 years for project approval, budgeting, and design; up to 1 year for equipment procurement; up to 1 year for installation, commissioning, and start-up; and up to 2 years for the design and construction of associated electricity infrastructure (new distribution lines and substation upgrades). This does not account for any facility-specific challenges that would prolong implementation.
- Electrification, inherent to its design, significantly increases a facility's electricity demand.
- The economic feasibility of electrification at a particular facility is highly dependent on two factors, the availability of requisite utility-supplied electricity and the distance from the facility to the nearest electrical substation. If a facility does not have access to utility-supplied electricity or the facility's existing electricity infrastructure cannot support at least one EMD unit, the cost of electrification is significant. For example, the estimated cost of installing new distribution lines from a substation to a facility is typically more than $750,000 per mile (2024$).

Retirement

When a facility's operational plans can accommodate retiring an emissions unit, doing so is a simple and effective control option. Retirement, in this context, means permanently shutting down a unit and forgoing its capacity by not replacing it, which reduces emissions by 100 percent. Retirement is a technically feasible option for any type of emissions unit, including 4SRB RICE. NMED believes a reasonable compliance time for retirement is 1-2 years depending on a facility's requisite planning time and operational flexibility. More time will be necessary when a facility needs a unit to satisfy anticipated near-term capacity requirements relative to a facility with excess capacity. There are no energy or non-air quality impacts associated with retirement.

C.3.4 Combustion Turbines

NMED determined that the following controls for reducing NO_X emissions from natural gas-fired CT are commercially available.

Good Combustion Practices

As discussed in Section C.3.1, Good Combustion Practices (GCP) describes the optimal design and proper operation and maintenance (O&M) of an emissions unit. In the case of CT, GCP typically involves maintenance with trained personnel and includes routine inspections, timely and appropriate overhauls, vibration and heat rate analyses, and the use of pipeline quality natural gas. A CT overhaul is generally needed every 4-5 years depending on maintenance, runtime, and other factors and may include testing of the turbine and compressor, rotor removal, a comprehensive inspection of various components (e.g., rotor, blades, bearings, and seals), and replacement of worn components.

Optimal O&M of a CT maximizes useful life and fuel efficiency, minimizes emissions, reduces costs, and improves safety – benefits desirable to owners of CT. Thus, CT manufacturers are highly incentivized to design highly optimized units, and owners of existing CT understand the benefits of following proper O&M schedules and procedures.

Based on a review of various information provided by CT manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- GCP is a technically feasible control option for reducing NO_X emissions from CT.
- The NO_X control efficiency associated with GCP varies significantly as it depends on the age and condition of the unit and what other controls (if any) have been installed.
- The compliance time for GCP is 0-1 years. If a facility does not already implement GCP, up to a year may be necessary to obtain O&M documentation and train personnel.
- There are no energy or non-air quality impacts associated with GCP.

Dry Low NO_X Combustion

Dry Low NO_X combustion (DLN), aka Dry Low Emissions or SoLoNOx,[3] is a technology employed in CT to reduce the production of NO_X during combustion. This is accomplished by creating a homogenous and lean fuel/air mix prior to injection into the combustor. Additionally, DLN systems often utilize sensors and sophisticated control algorithms to continuously monitor and optimize combustion conditions, ensuring minimal NO_X production without compromising turbine performance.

The term DLN collectively refers to a combination of two combustion technologies: conventional diffusion flame combustion at <50 percent load and DLN combustion at higher loads. Flame instability at lower loads is the reason for this hybrid approach. Since NO_X emissions can vary based on load, ambient conditions, CT size, and design of the combustion system, the NO_X emission rate of current generation DLN is often in the 9 to 15 ppm range but can be as high as 25 ppm. Enhanced DLN technology – aka Ultra-Low NO_X – can achieve as low as 5 ppm in certain applications.

The benefits of DLN extend beyond environmental considerations. By reducing NO_X emissions without relying on water or steam injection, DLN systems enhance overall turbine efficiency, leading to improved fuel economy and lower operating costs. These advantages are well understood and widely documented, and DLN is consequently utilized in various industrial and commercial CT applications. Many CT manufacturers assert that current generation DLN is the most efficient and cost-effective approach to minimizing NO_X emissions.

Based on a review of various information provided by CT manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- DLN is a technically feasible control option for reducing NO_X emissions from CT.
- The NO_X control efficiency associated with DLN varies as it depends on the existing NO_X emission rate and the target (post-retrofit) emission rate. Manufacturers will typically provide a post-retrofit NO_X emissions warranty, which varies based on make, model, age, and other factors.
- The general compliance time for DLN is estimated to be 2-3 years. This does not account for any facility-specific challenges that would prolong implementation.
- There are no appreciable energy or non-air quality impacts associated with DLN.

[3] SoLoNOx refers specifically to Solar Turbines' dry low emissions technology for its Centaur, Mars, Taurus, and Titan gas turbine families.

Water and Steam Injection

Water and steam injection[4] (WSI) has been used since the 1970s as a means of controlling NO_X emissions from CT. Inside a CT, fuel rich zones that create high flame temperatures are the result of the simultaneous mixing of fuel and air and their subsequent combustion. Injecting water or steam into the flame area of the combustor provides a heat sink that lowers the combustion zone temperature and reduces thermal NO_X formation. As the combustion zone temperature decreases, NO_X production decreases significantly.

Water is more efficient for reducing the flame temperature than steam, as the energy required to vaporize the water creates a larger heat sink. Generally, the steam flow required is 1.5-2 times the amount of water required for a given amount of NO_X reduction. WSI systems are designed to a specific "water-to-fuel ratio" which has a direct impact on the controlled NO_X emission rate and is generally controlled by the turbine inlet temperature and ambient temperature.

There are several disadvantages to WSI. First, the thermodynamic efficiency of a CT equipped with WSI will decrease due to the energy required to convert water into steam. Second, the water used must be of high quality (e.g., demineralized water) to prevent deposits and corrosion from occurring in the CT. While many combined cycle facilities may have existing demineralized water treatment on site, existing simple cycle facilities often do not. Third, in the case of remote locations, water availability may be a barrier, particularly in arid environments. Finally, WSI can cause an increase in combustor dynamic pressure which can accelerate wear and reduce the useful life of the CT.

Compared to other NO_X emission control technologies, WSI may have a lower capital cost, but higher variable costs. This can make WSI attractive for peaking combustion turbines or other units that operate infrequently. It is more often applied to smaller frame CT or retrofits of older CT, rather than new mid-sized or large-frame heavy duty turbines.

Based on a review of various information provided by CT manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- WSI is a technically feasible control option for reducing NO_X emissions from some CT models. Notably, Solar Turbines, which manufactured many of the CT subject to Regional Haze in New Mexico, does not offer WSI technology for its turbines based on the superior performance (i.e., lower NO_X emissions) and lower operational cost of its SoLoNOx (DLN) technology.
- Despite being a somewhat antiquated technology, WSI can achieve NO_X emissions below 42 ppm.
- The general compliance time for WSI is estimated to be 2-3 years. This does not account for any facility-specific challenges that would prolong implementation.
- A WSI retrofit on a CT can increase CO emissions and requires notable quantities of demineralized water.

[4] Because of their limited application and similar function, water injection and steam injection are collectively addressed, and referred to herein, as a single technology. Most of this technology description was obtained from Sargent & Lundy, *Combustion Turbine NOx Control Technology Memo* (January 2022).

Selective Catalytic Reduction

See Section C.3.1 for a description of this technology.

Based on a review of various information provided by CT manufacturers and SCR vendors, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- SCR is a technically feasible control option for reducing NO_X emissions from CT.
- A well designed and operated SCR system can (in general) reduce NO_X emissions by more than 90 percent. However, for units that operate intermittently, such as natural gas compressor drivers, NO_X removal efficiency may be lower due to decreased efficiency when the system is below the optimum temperature following cold starts. Depending on such a unit's annual operating profile, the average NO_X removal efficiency of SCR could reasonably vary from approximately 75 to 85 percent.
- Because SCR reactors can be fairly large, physical space limitations at existing facilities can necessitate significant modifications to a building's structure to accommodate SCR. The addition of SCR can also require considerable modifications to existing ductwork. Any such modifications are expected to appreciably increase the capital costs of implementing SCR.
- NMED believes a reasonable compliance time for SCR is 3-4 years. This estimate is based on the following timeframes for project development: 1-2 years for project approval, budgeting, and design; up to 1 year for equipment procurement; and up to 1 year for installation, commissioning, and start-up. This does not account for any facility-specific challenges that would prolong implementation.
- Operation of SCR on a CT would likely result in a small increase in fuel consumption, as additional power would be needed to force exhaust through the catalyst bed. Additionally, electricity is needed to operate SCR.

Selective Non-Catalytic Reduction

See Section C.3.1 for a description of this technology.

Based on a review of various information provided by CT manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- SNCR is not a technically feasible control option for CT because the exhaust temperature is well below the effective temperature range.

Replacement with a New CT

Current generation CT have significantly lower NO_X emissions rates than those manufactured 30 plus years ago. The vast majority of CT subject to Regional Haze in New Mexico are more than 30 years old, and a few are more than 70 years old. NMED and EPA agree that replacing an old CT with a new, like-kind or functionally equivalent, more efficient, lower emitting CT is within the scope of Regional Haze and thus an option states can consider when evaluating potential controls for CT.

Based on a review of various information provided by CT manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- Replacement with a new CT is a technically feasible control option for reducing NO_X emissions from CT.
- The NO_X control efficiency associated with CT replacement varies significantly as it depends on the NO_X emission rate of the existing unit and that of the replacement unit. Consistent with the emission standards for new natural gas-fired CT in 20.2.50 NMAC, the NO_X emission rate of a replacement CT would typically be in the 9 to 15 ppm range.
- NMED believes a reasonable compliance time for CT replacement is 3-4 years. This estimate is based on the following timeframes for project development: 1-2 years for project approval, budgeting, and design; up to 1 year for equipment procurement; and up to 1 year for installation, commissioning, and start-up. This does not account for any facility-specific challenges that would prolong implementation.
- There are no appreciable energy or non-air quality impacts associated with CT replacement. NMED understands that, in limited circumstances, the electricity demand of a facility could increase following CT replacement.

Electrification

Natural gas compression technology has advanced significantly since many of the CT subject to Regional Haze in New Mexico were installed. Several manufacturers now offer zero-emitting gas compression systems powered by electric motor drives (EMD). The use of EMD, commonly referred to as electrification, in the gas compression industry is becoming more prevalent as operators realize the lifecycle costs of EMD-powered systems can be considerably less than those of traditional systems powered by fossil fuel-fired CT.

Based on a review of various information provided by CT manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- Electrification is a technically feasible control option for reducing NO_X emissions from CT.
- The NO_X control efficiency associated with electrification is 100 percent. EMD do not emit NO_X or any other pollutants.
- NMED believes a reasonable compliance time for electrification is 4-6 years. This estimate is based on the following timeframes for project development: 1-2 years for project approval, budgeting, and design; up to 1 year for equipment procurement; up to 1 year for installation, commissioning, and start-up; and up to 2 years for the design and construction of associated electricity infrastructure (new distribution lines and substation upgrades). This does not account for any facility-specific challenges that would prolong implementation.
- Electrification, inherent to its design, significantly increases a facility's electricity demand.
- The economic feasibility of electrification at a particular facility is highly dependent on two factors, the availability of requisite utility-supplied electricity and the distance from the facility to the nearest electrical substation. If a facility does not have access to utility-supplied electricity or the facility's existing electricity infrastructure cannot support at least one EMD unit, the cost of electrification is significant. For example, the estimated cost of installing new distribution lines from a substation to a facility is typically more than $750,000 per mile (2024$).

Retirement

When a facility's operational plans can accommodate retiring an emissions unit, doing so is a simple and effective control option. Retirement, in this context, means permanently shutting down a unit and forgoing its capacity by not replacing it, which reduces emissions by 100 percent. Retirement is a technically feasible option for any type of emissions unit, including CT. NMED believes a reasonable compliance time for retirement is 1-2 years depending on a facility's requisite planning time and operational flexibility. More time will be necessary when a facility needs a unit to satisfy anticipated near-term capacity requirements relative to a facility with excess capacity. There are no energy or non-air quality impacts associated with retirement.

C.3.5 Boilers

NMED determined that the following controls for reducing NO_X emissions from natural gas-fired industrial and utility boilers are commercially available.

Good Combustion Practices

As discussed in Section C.3.1, Good Combustion Practices (GCP) describes the optimal design and proper operation and maintenance (O&M) of an emissions unit. In the case of boilers, GCP typically involves maintenance with trained personnel and includes (but is not limited to) routine inspections and tune-ups. A tune-up generally involves conducting an evaluation of existing equipment (e.g., oxygen probes and other instrumentation, burners, dampers, tilt mechanisms, and actuators) to determine if equipment needs to be cleaned, repaired, or replaced. Tune-ups also provide an opportunity to investigate levels of excess air and emissions of NO_X and CO, unusual temperatures and pressures, and leakage. Collected data is analyzed and used to adjust control settings as necessary to achieve optimal combustion and sustainable operation of the unit.

Optimal O&M of a boiler maximizes useful life and fuel efficiency, minimizes emissions, reduces costs, and improves safety – benefits desirable to boiler owners. Thus, boiler manufacturers are highly incentivized to design highly optimized units, and boiler owners understand the benefits of following proper O&M schedules and procedures.

Based on a review of various information provided by boiler manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- GCP is a technically feasible control option for reducing NO_X emissions from a boiler.
- The NO_X control efficiency associated with GCP varies significantly as it depends on the age and condition of the unit and what other controls (if any) have been installed.
- The compliance time for GCP is 0-1 years. If a facility does not already implement GCP, up to a year may be necessary to obtain O&M documentation and train personnel.
- There are no energy or non-air quality impacts associated with GCP.

Staged Combustion (Low NO_X Burners)

A staged combustion process uses more than one combustion zone to optimize combustion and reduce NO_X emissions. In fuel-lean zones, the combustion temperature is lowered, reducing the production of NO_X. In fuel-rich zones, both the combustion temperature and oxygen concentrations are lowered. While

there are several forms of staged combustion (e.g., overfire air, burners out of service, biased burner firing), the most prevalent and effective form for natural gas combustion in a boiler is low NO_X burners (LNB).

LNB on a boiler that is several decades old may have a NO_X emission rate of ~50 ppm, whereas LNB on a new boiler may have a NO_X emission rate of 12 to 15 ppm. The term "ultra-low NO_X burner" (ULNB) has evolved to generally refer to a burner that emits less than 9 ppm NO_X. Several ULNB designs are constructed using composite materials and designed for precise fuel and air premixing prior to injection into the furnace combustion zone. The tolerance of ULNB operating conditions is very tight and must be closely monitored to ensure that the produced emissions are as expected.

Based on a review of various information provided by boiler manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- LNB is a technically feasible control option for reducing NO_X emissions from boilers.
- The NO_X control efficiency associated with LNB varies by boiler model, boiler age, and burner selection. Manufacturers typically provide a target (post-retrofit) NO_X emissions warranty for LNB.
- The general compliance time for LNB is estimated to be 2-3 years. (This does not account for company or facility specific challenges that would prolong implementation.)
- There are no appreciable energy or non-air quality impacts associated with LNB.

Flue Gas Recirculation

As the name suggests, flue gas recirculation (FGR) involves the recirculation of a portion – typically 20 to 30 percent – of the relatively cool exhaust gases back into the boiler combustion zone. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. FGR reduces NO_X emissions by two mechanisms. Primarily, the recirculated gas acts as a diluent to reduce combustion temperatures, thus suppressing the thermal NO_X formation mechanism. To a lesser extent, FGR also reduces NO_X formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is an important operating parameter influencing NO_X emission reduction potential for boiler systems.

Based on a review of various information provided by boiler manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- FGR is a technically feasible control option for reducing NO_X emissions from boilers.
- Physical space limitations at existing facilities can necessitate significant modifications to a building's structure to accommodate FGR. The addition of FGR can also require considerable modifications to existing ductwork (in configuration and capacity), re-design of a boiler's windbox, enlargement of burner nozzles, and new controls. Any such modifications are expected to appreciably increase the capital costs of retrofitting a boiler with FGR.
- The degree of NO_X reductions achieved with FGR vary considerably depending on the type of fuel and the design of the system. For example, when used in conjunction with LNB, FGR typically reduces NO_X emissions from natural gas-fired boilers by 50-90 percent.

- The general compliance time for FGR is estimated to be 2-3 years. This does not account for any facility-specific challenges that would prolong implementation.
- There are no appreciable energy or non-air quality impacts associated with FGR.

Selective Catalytic Reduction

See Section C.3.1 for a description of this technology.

Based on a review of various information provided by boiler manufacturers and SCR vendors, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- SCR is a technically feasible control option for reducing NO_X emissions from boilers.
- A well designed and operated SCR system can (in general) reduce NO_X emissions by more than 90 percent.
- Because SCR reactors can be fairly large, physical space limitations at existing facilities can necessitate significant modifications to a building's structure to accommodate SCR. The addition of SCR can also require considerable modifications to existing ductwork. Any such modifications are expected to appreciably increase the capital costs of implementing SCR.
- NMED believes a reasonable compliance time for SCR is 3-4 years. This estimate is based on the following timeframes for project development: 1-2 years for project approval, budgeting, and design; up to 1 year for equipment procurement; and up to 1 year for installation, commissioning, and start-up. This does not account for any facility-specific challenges that would prolong implementation.
- Operation of SCR on a boiler would likely result in a small increase in fuel consumption, as additional power would be needed to force exhaust through the catalyst bed. Additionally, electricity is needed to operate SCR.

Selective Non-Catalytic Reduction

See Section C.3.1 for a description of this technology.

Based on a review of various information provided by boiler manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- SNCR is a technically feasible control option for reducing NO_X emissions from boilers only if the temperature of the boiler exhaust is high enough.

EMx™ (formerly SCONOx)

EMx™ is a proprietary emissions control system, previously offered by Emerachem, designed to reduce NO_X, CO, and VOC. Like SCR, EMx utilizes a catalyst to promote reactions at a temperature lower than what would be required otherwise. However, unlike SCR, EMx simultaneously reduces multiple pollutants without the use of ammonia and thus does not potentially increase PM10 emissions.

According to an Emerchem representative,[5] EMx requires significantly more physical space than a traditional SCR system and would likely cost five to ten times as much.

Following the first commercial installation in 1997, the U.S. EPA designated EMx as BACT and LAER for natural gas-fired CT, and subsequently as Maximum Achievable Control Technology (MACT) for formaldehyde, acetaldehyde, and benzene. Capable of effective operation with exhaust temperatures as low as 300°F, the technology may be well suited for a variety of combustion applications. However, commercial application of EMx has been limited to large-scale CT and reciprocating engine installations. According to publicly available resources, EMx technology has not been employed on a natural gas-fired boiler. As a result, NMED determined that EMx is not a technically feasible control option for reducing NO_X emissions from boilers.

Replacement with a New Boiler

New boilers typically have significantly lower NO_X emission rates than those manufactured 30 plus years ago. All of the boilers subject to Regional Haze in New Mexico are at least 50 years old. NMED and EPA agree that replacing an old boiler with a new, more efficient, lower emitting boiler is within the scope of Regional Haze and thus an option states can consider when evaluating potential controls for boilers.

Based on a review of various information provided by boiler manufacturers and licensed service entities, FFAs completed by other air quality agencies, and discussions with industry representatives, NMED determined that:

- Replacement with a new boiler is a technically feasible control option for reducing NO_X emissions from boilers.
- The NO_X control efficiency associated with boiler replacement varies significantly as it depends on the NO_X emission rate of the existing unit and that of the replacement unit.
- NMED believes a reasonable compliance time for boiler replacement is 3-4 years. This estimate is based on the following timeframes for project development: 1-2 years for project approval, budgeting, and design; up to 1 year for equipment procurement; and up to 1 year for installation, commissioning, and start-up. This does not account for any facility-specific challenges that would prolong implementation.
- There are no appreciable energy or non-air quality impacts associated with boiler replacement.

Electrification

A Boiler is designed to produce useful thermal energy (e.g., steam). It is well-documented and widely understood that using electricity to generate steam is extremely inefficient and cost prohibitive. As a result, NMED determined that electrification is not a technically feasible control option for reducing NO_X emissions from boilers.

Retirement

When a facility's operational plans can accommodate retiring an emissions unit, doing so is a simple and effective control option. Retirement, in this context, means permanently shutting down a unit and forgoing its capacity by not replacing it, which reduces emissions by 100 percent. Retirement is a

[5] During a discussion in 2019 with NMED's contractor.

technically feasible option for any type of emissions unit, including boilers. NMED believes a reasonable compliance time for retirement is 1-2 years depending on a facility's requisite planning time and operational flexibility. More time will be necessary when a facility needs a unit to satisfy anticipated near-term capacity requirements relative to a facility with excess capacity. There are no energy or non-air quality impacts associated with retirement.

C.3.6 Amine Treatment Systems

Natural gas extracted from the earth often contains varying concentrations of hydrogen sulfide (H_2S) and carbon dioxide (CO_2). These compounds are generally considered contaminants to natural gas streams because they can react with water to form corrosive acids. Therefore, natural gas processing plants use amine treatment systems (ATS) typically consisting of an amine treatment unit (ATU) and one or more downstream control devices to remove and dispose of H_2S and CO_2 to protect pipelines from corrosion damage.

An ATU operates by feeding the inlet (i.e., unprocessed) natural gas stream into the bottom of a contactor while simultaneously feeding a lean amine solution into the top of the contactor. The two streams interact in counter flow, resulting in H_2S and CO_2 being stripped from the natural gas stream through amine absorption. The resulting "sweet gas" leaves the top of the contactor containing almost no H_2S. Rich amine leaves the bottom of the contactor and is fed into a stripper column to remove the absorbed H_2S and CO_2 so it can be reused, a process known as regeneration. The resulting "acid gas" stream is then sent to a control device for disposal. When the control device utilizes combustion to dispose of the acid gas stream, the H_2S is converted to sulfur dioxide (SO_2), which is released to the atmosphere along with the CO_2 in the stream.

NMED determined that the following controls for disposing of ATS acid gas streams are commercially available.

Flare[6]

Flaring is a high-temperature oxidation process used to burn waste gases containing combustible components such as volatile organic compounds, natural gas (or methane), carbon monoxide, and hydrogen. The waste gas is piped to a remote, usually elevated location and burned in an open flame in ambient air using a specially designed burner tip, auxiliary fuel, and, in some cases, assist gases like steam or air to promote mixing for nearly complete (e.g., greater than 98 percent) destruction of the combustible components in the gas. Flares are generally categorized by the height of the flare tip (i.e., ground or elevated) and by the method of enhancing mixing at the flare tip (i.e., steam-assisted, air-assisted, pressure-assisted, or non-assisted).

Based on a review of various information provided by facilities, as well as information available from EPA and flare manufacturers, NMED determined that:

- A flare is a technically feasible control option for disposing of ATS acid gas streams.
- If used as the primary control device, a flare is inferior to all other forms of disposal because most of the H_2S in the acid gas stream (typically 98% or more) is converted to SO_2 and emitted

[6] Most of this technology description was obtained from EPA's *Air Pollution Control Cost Manual*, Section 3.2, VOC Destruction Controls, Chapter 1 – Flares (updated August 2019).

into the atmosphere. Therefore, NMED did not evaluate replacing other, existing ATS control devices with a flare.

- Every facility with an ATS evaluated by NMED uses a flare as a secondary control device that only combusts acid gas when a primary control device experiences a startup, shutdown, and maintenance or malfunction (SSM/M) event. Improved flare design might reduce emissions somewhat in this context, but the potential marginal improvement in combustion efficiency – perhaps 1 to 2 percentage points – from the most optimized flare is not anticipated to be a cost-effective option for reducing SO_2 emissions from acid gas flaring during SSM/M events as any modification to the flare would incur considerable costs associated with additional design, engineering, procurement, construction, and testing. Therefore, NMED did not evaluate optimizing existing flares used as a secondary control device.

Sulfur Recovery Unit (with Flare or Incinerator)

A sulfur recovery unit (SRU) converts the H_2S in an ATS acid gas stream to elemental sulfur and water using the Claus Process. A SRU typically involves multiple stages, with each stage consisting of a catalytic reactor, gas reheater, and a condenser/cooler. Depending on the exact configuration, a SRU can convert 90 percent or more of the H_2S in the acid gas stream to elemental sulfur. The "tail gas" exiting the SRU is typically sent to a flare or incinerator to combust any residual H_2S.

Based on a review of various information provided by facilities, and information available from EPA and publicly available resources, NMED determined that:

- A SRU (combined with a flare or incinerator) is a technically feasible control option for disposing of ATS acid gas streams.
- No facility with an ATS evaluated by NMED currently uses a SRU. Many, and possibly all gas processing plants in New Mexico that previously used a SRU have decommissioned them in recent years due to operational concerns and/or compliance issues, some of which resulted in enforcement actions against the facility due to significant excess SO_2 emissions. NMED supports and encourages the transition away from SRUs towards more effective forms of acid gas disposal, such as acid gas injection (AGI) wells. Therefore, NMED did not evaluate replacing other, existing ATS control devices with a SRU.

Thermal Oxidizer[7]

A thermal oxidizer (TO), also known as an incinerator, combusts waste gases in a combustion chamber as opposed to an open flame. The heart of a TO is a nozzle-stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. Ignition of the waste gas occurs as it passes through the combustion chamber, resulting in the destruction of H_2S and other volatile organic compounds. The exhaust gas from the TO consists primarily of CO_2 and water, plus various combustion products (e.g., SO_2) and any uncombusted hydrocarbons.

[7] Most of this technology description was obtained from EPA's *Air Pollution Control Cost Manual*, Section 3.2, VOC Destruction Controls, Chapter 2 – Incinerators and Oxidizers (updated November 2017).

Based on a review of various information provided by facilities, as well as information available from EPA and publicly available resources, NMED determined that:

- A TO is a technically feasible control option for disposing of ATS acid gas streams.
- Every facility with an ATS evaluated by NMED uses either a TO or an AGI well for acid gas disposal. Where an AGI well is technically feasible, a TO is an inferior control. An ATS with a TO will produce SO_2 emissions during normal operations and during SSM/M flaring events. Conversely, an ATS with an AGI well will produce SO_2 emissions only during SSM/M flaring events. Therefore, NMED did not evaluate replacing an existing AGI well with a TO, as this would increase emissions.

Acid Gas Injection Well

An AGI well is used to inject an ATS acid gas stream into a porous geologic formation (typically comprised of sandstone or limestone) for permanent underground storage. Prior to injection, the gas is pressurized to the required injection pressure using compressors powered by conventional natural gas-fired reciprocating engines or electric motor drives (EMD). During normal operations, an ATS controlled by an AGI well produces no atmospheric emissions of any kind. As such, emissions related to the operation of an ATS with an AGI well are limited to those that occur during SSM/M events, during which the acid gas stream is rerouted to a secondary control device, typically a flare, for disposal.

Based on its experience, a review of various information provided by facilities, and information available from EPA, NMED determined that:

- The technical feasibility of an AGI well is extremely dependent on the geologic characteristics of the potential well site. A subsurface investigation must be performed to determine if a suitable reservoir exists beneath the site. Only where a suitable reservoir exists is an AGI well a technically feasible control option for disposing of ATS acid gas streams.
- An AGI well can significantly reduce the amount of SO_2 released into the atmosphere compared to other forms of acid gas disposal. An ATS with a SRU or TO will produce SO_2 emissions during normal operations and during SSM/M flaring events. Conversely, an ATS with an AGI well will produce SO_2 emissions only during SSM/M flaring events. As a result, NMED has been actively encouraging and promoting the use of AGI wells in place of other controls, especially SRUs, in recent years.
- Because emissions from an ATS with an AGI well depend on the amount of acid gas flared during AGI SSM/M events, reducing the number and duration of SSM/M events can be an effective approach to reducing AGI-related flaring emissions. This can be primarily accomplished in one of two ways: 1) installation of a secondary acid gas compressor to provide backup, redundant compression in the event the primary compressor fails or is taken out of service for maintenance; or 2) implementation of an SSM/M plan which outlines a combination of work practice standards (proper maintenance and operation) consistent with manufacturer recommendations and industry best practices.
- All Title V facilities in New Mexico are already required to establish and implement SSM/M plans. Therefore, for facilities with an AGI well without redundant compression, NMED limited its evaluation to adding redundant compression to reduce AGI-related flaring emissions.

The use of an AGI well with redundant compression is an optimal approach to reducing emissions from an ATS. Therefore, for facilities with an AGI well with redundant compression, NMED did not evaluate alternative controls.

C.4 Four-Factor Analyses and Control Measure Determinations

NMED's four-factor analyses and reasonable progress control determinations for the emissions units selected for analysis via the screening process described in Section C.2 are described below.

C.4.1 Davis Gas Processing – Denton Gas Plant

Denton Gas Plant (DGP) is a former natural gas processing facility previously located 11 miles east of Lovington in Lea County, New Mexico at latitude 33° 2' 38", longitude -103° 10' 15". It was owned and operated by Davis Gas Processing, Inc. (Davis), and was one of 23 facilities selected for an analysis of potential control measures when NMED performed the source screening described in Section C.2 in 2019. However, Davis subsequently shut down DGP on December 1, 2022, and submitted an administrative permit revision closing NSR Permit No. 0065-M8 and voluntarily discontinuing Title V Operating Permit No. P079-R3 on February 2, 2022. Davis demolished the facility shortly thereafter.

NMED originally selected the ATS at DGP (comprising Units 005 and 007) for an analysis of potential control measures for SO_2 in the second planning period due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). However, because DGP has since been shut down and demolished, NMED did not perform a FFA of potential control measures for the ATS. EPA guidance provides that a state may forgo a full FFA if a source is already "effectively controlled" and the state can demonstrate why a FFA would not result in new controls and would therefore be a futile exercise.[8] NMED considers it self-evident that a FFA of potential control measures for a retired unit at a facility that has been shut down and demolished would be futile. There is no more effective control than retirement, which reduces emissions by 100 percent, and the demolition of DGP makes it impossible to add new controls. Therefore, NMED has determined that the ATS is effectively controlled by virtue of its retirement due to the shutdown of DGP, and that a FFA could only result in the conclusion that no further controls are necessary to make reasonable progress.

Based on when DGP was shut down, the emissions reductions resulting from the retirement of the ATS were realized during the second planning period. Therefore, NMED estimated the SO_2 emissions reductions resulting from the retirement of the ATS by averaging 2016-2021 emissions reported by Davis pursuant to 20.2.73 NMAC. These emissions are summarized below.

Pollutant	2016 Emissions (tons)	2017 Emissions (tons)	2018 Emissions (tons)	2019 Emissions (tons)	2020 Emissions (tons)	2021 Emissions (tons)	Average Emissions (ton/yr)
SO_2	951.6	687.6	738.6	541.7	696.0	632.6	708.0

[8] EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021) at 5.

C.4.2 DCP Operating Company – Artesia Gas Plant

Resources used in NMED's FFA for the Artesia Gas Plant (AGP) include, but are not limited to, the following:

- The FFA completed by Trinity Consultants for DCP Operating Company, LP (DCP) and submitted to NMED on or about 11/1/19.
- Additional information provided by DCP on 12/16/19 and 3/3/20.
- A detailed discussion between DCP and NMED on 7/12/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA's Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP Region (March 23, 2020).
- FFAs developed for similar facilities in New Mexico and other states.

C.4.2.1 Facility Description

AGP is a natural gas processing facility located 13 miles east-southeast of Artesia in Eddy County, New Mexico at latitude 32^{o} 45' 18", longitude -104^{o} 12' 36". It is owned and operated by DCP and currently operates under Title V Operating Permit No. P095-R4, which expires on March 8, 2028. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 39.8 miles.

The function of the facility is to process natural gas, including condensate removal, H_2S and CO_2 removal with an amine unit, separation of natural gas liquids through the cryogenic plant, and inlet and residue compression. The facility is authorized for continuous operation, and its total potential to emit is 476.0 tons per year of NO_X and 389.3 tons per year of SO_2.[9]

C.4.2.2 Evaluated Units

NMED elected to evaluate the ATS at AGP for potential control measures for SO_2 due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). The ATS at AGP consists of an ATU (Units Amine Contactor and Amine-RS), AGI well and compressor (Unit AGI), and an acid gas flare (Unit 23). During normal operations, acid gas exiting the ATU is routed to the AGI well for disposal resulting in no emissions to the atmosphere. During AGI SSM/M events, acid gas is rerouted to the acid gas flare for disposal, which produces SO_2 emissions.

[9] AQB Title V Operating Permit No. P095-R4, Table 102.A.

C.4.2.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. DCP did not request a future utilization adjustment for AGP. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the ATS at AGP.

NMED estimated baseline actual SO_2 emissions for the ATS at AGP by averaging 2016-2021 emissions reported by DCP pursuant to 20.2.73 NMAC.[10] These emissions are summarized below.

Unit No.	2016 Emissions (tons)	2017 Emissions (tons)	2018 Emissions (tons)	2019 Emissions (tons)	2020 Emissions (tons)	2021 Emissions (tons)	Average Emissions (ton/yr)
23	17.96	0.04	109.96	3.25	0.00	0.03	27.8
SSM	NR (1)	0.31	NR (1)	3.36	NR (1)	NR (1)	
Malfunction	5.80	7.45	8.53	6.46	3.48	NR (1)	

(1) NR = None Reported

DCP only reports total SSM and total malfunction emissions, which include AGI SSM/M emissions from the acid gas flare associated with the ATS. Because NMED was unable to determine what portion of total SSM and total malfunction emissions were attributable to AGI SSM/M events, NMED conservatively assumed that 100 percent of total SSM and total malfunction emissions were AGI SSM/M emissions.

C.4.2.4 Technical Feasibility of Available Controls

As indicated in Section C.3.6, the following determinations were made regarding the technical feasibility of identified control options for the ATS at AGP:

- A flare, SRU or TO are technically feasible options. However, compared to an AGI well, which is currently used as the primary control device for the ATS at AGP, a flare, SRU or TO is an inferior control. An ATS with a flare, SRU or TO will produce SO_2 emissions during normal operations and during SSM/M events. Conversely, an ATS with an AGI well will produce SO_2 emissions only during AGI SSM/M events. Therefore, NMED did not evaluate these options.
- While improved flare design might reduce emissions somewhat during AGI SSM/M events, the potential marginal improvement in combustion efficiency – perhaps 1 to 2 percentage points – from the most optimized flare is not anticipated to be a cost-effective option for reducing SO_2 emissions from acid gas flaring during AGI SSM/M events. Therefore, NMED did not evaluate this option.
- Adding backup, redundant compression to the ATS is a technically feasible option for reducing SO_2 emissions from acid gas flaring during AGI SSM/M events.

[10] NMED was in receipt of DCP's reported 2022 emissions at the time of its analysis, but the data were still undergoing internal QA/QC checks and had not been certified yet, so NMED excluded them from its analysis.

C.4.2.5 Four-Factor Analysis

In order to determine what control measures are necessary at AGP to make reasonable progress, NMED conducted a FFA of the only technically feasible control option for the ATS, i.e., adding redundant compression to reduce AGI SSM/M flaring emissions. States are required to consider four statutory factors – cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[11]

C.4.2.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of SO_2 emissions reduced, of adding redundant compression to the ATS at AGP. Because DCP did not evaluate the ATS and therefore did not provide a source-specific cost estimate for adding redundant compression, NMED utilized cost estimates for adding redundant compression provided by other natural gas processing facilities in New Mexico to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[12]

NMED's cost effectiveness value for adding redundant compression to the ATS at AGP is provided below. NMED believes this value was calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed calculations and supporting documentation for NMED's cost estimate are provided in Appendix D.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
ATS	Redundant Compression	$403,619	25.0	$16,000

NMED notes the following with respect to its determination of cost effectiveness for adding redundant compression to the ATS at AGP:

- DCP did not provide a company-specific cost of capital, so the bank prime rate (7.5 percent as of December 2024) was used to determine the appropriate capital recovery factor.
- Cost estimates for adding redundant compression provided by other natural gas processing facilities in New Mexico ranged from approximately $4.1M to $14.5M (2023$). NMED did not have sufficient information to determine which of the available estimates best represents the cost of adding redundant compression at AGP, so NMED conservatively used the lowest estimate in its calculations.

C.4.2.5.2 Compliance Time

Based on several recently completed projects, NMED believes a reasonable compliance time for adding redundant compression is 2-3 years. This does not account for any facility-specific challenges that would prolong implementation.

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[11] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).

[12] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

C.4.2.5.3 Remaining Useful Life

There is limited information about the useful life of EMD units, but research suggests the useful life is generally at least 25 years for units used in natural gas compression service. However, since in this case the unit would be used in acid gas service, NMED believes the useful life would not be longer than 20 years.

C.4.2.5.4 Energy and Non-Air Quality Impacts

NMED anticipates no energy or non-air quality impacts from adding redundant compression.

C.4.2.5.5 Summary

NMED performed a FFA for the only technically feasible control option for the ATS at AGP, i.e., adding redundant compression to reduce AGI SSM/M flaring emissions. The four statutory factors are discussed in Sections C.4.2.5.1 through C.4.2.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
ATS	Redundant Compression	$16,000	2-3	20	None

C.4.2.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[13]

[13] EPA, Responses to Comments on Protection of Visibility: Amendments to Requirements for State Plans (December 2016) at 186 ("While the CAA lists the four reasonable progress factors, it is silent as to whether states or the EPA may consider other, additional factors. This final rule neither requires nor prohibits states from considering visibility when making reasonable progress determinations."). *See also* EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) at 28 ("Section 169A(g)(1) of the CAA lists four factors that must be taken into consideration in determining reasonable progress … The visibility benefit of an emission reduction measure is not listed as a required factor, but neither the CAA nor the Regional Haze Rule prohibits a state from considering visibility benefits when it determines what emission control measures are required for a source to make reasonable progress at a Class I Area. Therefore, a state **may** consider the visibility benefits of potential control measures when determining what is necessary to make reasonable progress.")(emphasis added).

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. Because the estimated cost effectiveness of redundant compression exceeds this threshold, NMED determined that reasonable progress does not require adding redundant compression to the ATS at AGP.

C.4.3 DCP Operating Company – Eunice Gas Plant

Eunice Gas Plant (EGP) is a former natural gas processing facility located 7 miles northwest of Eunice in Lea County, New Mexico at latitude 32° 30' 31", longitude -103° 17' 08". It was owned and operated by DCP Operating Company, LP (DCP), and was one of 23 facilities selected for an analysis of potential control measures when NMED performed the source screening described in Section C.2 in 2019. However, DCP subsequently entered into a Settlement Agreement and Stipulated Final Compliance Order (SASFCO) with NMED on September 10, 2021, which required DCP to permanently cease operations at EGP within 60 days and decommission the plant by removing process chemicals, including catalysts, and cleaning process vessels and piping within 270 days.[14] As required by the SASFCO, DCP shut down EGP on June 6, 2021, and submitted an administrative permit revision closing NSR Permit No. 0044-M11R1 and voluntarily discontinuing Title V Operating Permit No. P086-R2 on November 3, 2021.[15]

NMED originally selected EGP's five combustion turbines (Units 17A, 18A, 19A, 25A, and 26A) for an analysis of potential control measures for NO_X in the second planning period. NMED also elected to evaluate the ATS at EGP (comprising Units Amine-01, 31, 111, and 113) for potential control measures for SO_2 due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). However, because EGP has since been shut down and decommissioned pursuant to the SASFCO, NMED did not perform a FFA of potential control measures for any of these units. EPA guidance provides that a state may forgo a full FFA if a source is already "effectively controlled" and the state can demonstrate why a FFA would not result in new controls and would therefore be a futile exercise.[16] NMED considers it self-evident that a FFA of potential control measures for retired units at a facility that has been shut down and decommissioned would be futile. There is no more effective control than retirement, which reduces emissions by 100 percent, and the decommissioning of EGP makes it impossible to add new controls. Therefore, NMED has determined that these units are effectively controlled by virtue of their retirement due to the shutdown of EGP, and that a FFA could only result in the conclusion that no further controls are necessary to make reasonable progress.

Based on when EGP was shut down, the emissions reductions resulting from the retirement of the affected units were realized during the second planning period. Therefore, NMED estimated the NO_X emissions reductions resulting from the retirement of EGP Units 17A, 18A, 19A, 25A, and 26A and the SO_2 emissions reductions resulting from the retirement of the units comprising the ATS by averaging

[14] The SASFCO resolved alleged violations set forth in two Administrative Compliance Orders contested by DCP and docketed as AQB 20-46 (CO) and ABQ 20-64 (CO).

[15] DCP re-authorized certain equipment located at EGP but not part of the gas plant and not subject to the SASFCO, including the compressor station known as the Amanda Booster Station and the liquids stabilization and loading/unloading facilities known as the Eunice Treater, under two separate Oil and Gas General Construction Permits (GCP-O&G 9441 and 9442).

[16] EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021) at 5.

2016-2020 emissions reported by DCP pursuant to 20.2.73 NMAC. These emissions are summarized below.

Pollutant	2016 Emissions (tons)	2017 Emissions (tons)	2018 Emissions (tons)	2019 Emissions (tons)	2020 Emissions (tons)	Average Emissions (ton/yr)
NO_X	424.6	407.2	407.2	182.7	186.3	321.6
SO_2	1417.9	1371.7	1706.8	1252.0	1216.0	1392.9

C.4.4 DCP Operating Company – Linam Ranch Gas Plant

Resources used in NMED's FFA for the Linam Ranch Gas Plant (LRGP) include, but are not limited to, the following:

- The FFA completed by Trinity Consultants for DCP Operating Company, LP (DCP) and submitted to NMED on or about 11/1/19.
- Additional information provided by DCP on 12/16/19, 3/3/20, 8/28/23, 1/23/24, 1/25/24, and 2/5/24.
- A detailed discussion between DCP and NMED on 7/12/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA's Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP Region (March 23, 2020).
- FFAs developed for similar facilities in New Mexico and other states.

C.4.4.1 Facility Description

LRGP is a natural gas processing facility located 7 miles west of Hobbs in Lea County, New Mexico at latitude 32° 41' 43", longitude -103° 17' 07". It is owned and operated by DCP and currently operates under Title V Operating Permit No. P094-R3, which expires on December 18, 2025. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 72.7 miles.

The function of the facility is to remove hydrogen sulfide, water and carbon dioxide from field natural gas and separate natural gas liquids (NGL) from the field natural gas stream. The facility is authorized for continuous operation, and its total potential to emit is 973.5 tons per year of NO_X and 87.1 tons per year of SO_2.[17]

[17] AQB Title V Operating Permit No. P094-R3, Table 102.A.

C.4.4.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at LRGP:[18]

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
6	2SLB RICE	Clark TLA-6	1974 or before	2,000 hp
7	2SLB RICE	Clark TLA-6	1974 or before	2,000 hp
8 (1)	2SLB RICE	Clark HBA-6	1951	1,267 hp
9 (1)	2SLB RICE	Clark HBA-6	1951	1,267 hp
10	2SLB RICE	Clark HBA-6	1951	1,267 hp
11	2SLB RICE	Clark HBA-6	1951	1,267 hp
29	Turbine	Solar Taurus T-70	1995	10,702 hp
30	Turbine	Solar Taurus T-70	1995	9,900 hp
31	Turbine	Solar Centaur T-4700	1995	4,700 hp
32B	Turbine	Solar Centaur T-4000	1979	3,961 hp

(1) In a detailed discussion with NMED on 7/12/23, DCP indicated that Units 8 and 9 are not operational. In its 8/28/23 submittal, DCP indicated that these units (and Units 6, 7, 10, and 11) will "either be replaced with different technology or retrofitted with appropriate equipment for compliance with §20.2.50 NMAC." In its 1/16/24 submittal, DCP reiterated that it does not plan to retire Units 8 and 9 and will either replace them or add controls as necessary. Therefore, NMED conducted a FFA for these units using operating data for identical Units 10 and 11 as a surrogate.

NMED also elected to evaluate the ATS at LRGP for potential control measures for SO_2 due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). The ATS at LRGP consists of an ATU (Unit AM-10), AGI well (Unit AGI), two electric AGI well compressors (Units AGI-C1 and AGI-C2), and two acid gas flares (Units 2 and AGI Flare). During normal operations, acid gas exiting the ATU is routed to the AGI well for disposal resulting in no emissions to the atmosphere. During AGI SSM/M events, acid gas is rerouted to one of the flares for disposal, which produces SO_2 emissions. AGI SSM/M flaring emissions are minimized via the second, redundant AGI well compressor, which provides compression when the primary AGI well compressor fails or is taken out of service for maintenance, allowing for continued use of the AGI well when flaring would otherwise be required.

C.4.4.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. DCP did not request a future utilization adjustment for LRGP. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the emissions units at LRGP.

For the emissions units at LRGP requiring a FFA of potential control measures for NO_X ("NO_X units"), NMED calculated baseline actual emissions by multiplying representative annual operating hours by the NO_X emission rates reported in DCP's most recent periodic emissions test report(s).[19,] Because the NO_X

[18] See Chapter 6, Selection of Sources for Control Measures Analysis, for a detailed discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.
[19] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.

units at LRGP operate at varying loads, NMED conservatively adjusted reported emission rates to 100 percent load to represent worst-case emissions.[20] Furthermore, because DCP is in the process of upgrading Unit 32B with DLN for compliance with 20.2.50 NMAC, NMED assumed DLN has already been installed on this unit and adjusted its emission rate to account for the anticipated effect of DLN. Reported and adjusted emission rates for the NO_X units at LRGP are summarized below.

Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr @ 100% load)
6	2/15/23	25.5	43%	58.7
7	2/14/23	35.9	62%	58.1
8	NA [(1)]	---	---	18.1 [(2)]
9	NA [(1)]	---	---	18.1 [(2)]
10	2/15/23	19.1	71%	26.8
11	11/28/22	7.9	85%	9.3
29	2/13/23	1.0	86%	1.1
30	2/13/23	2.3	100%	2.3
31	2/14/23	3.0	100%	3.0
32B	10/11/22	15.4	95%	3.8 [(3)]

[(1)] NA = Not Available

[(2)] The average adjusted emissions of identical Units 10 and 11 were used as a surrogate for Units 8 and 9, as NMED was unable to locate a recent emissions test report for these units.

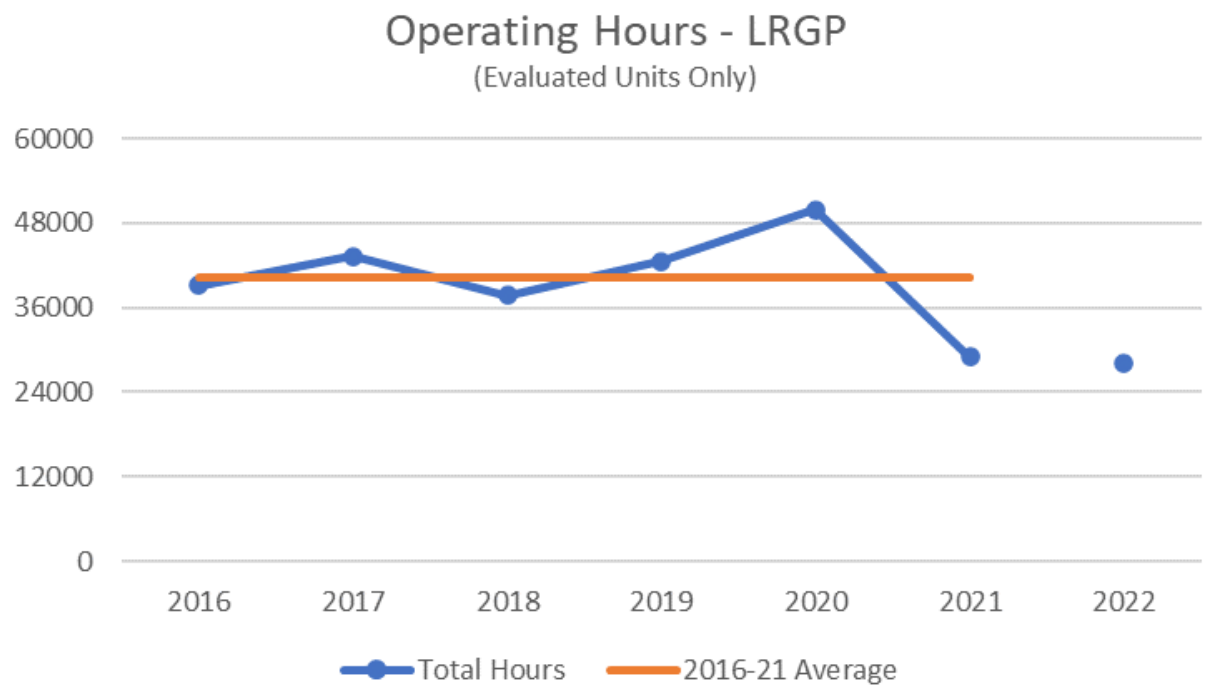
[(3)] Assumes 77% control efficiency for DLN, calculated as follows: (106.4 ppm - 25 ppm) / 106.4 ppm, where 106.4 ppm is the current actual emission rate and 25 ppm is the expected post-control emission rate after DLN is installed.

To determine representative annual operating hours for the NO_X units at LRGP, NMED analyzed 2016-2021 operating hours reported by DCP pursuant to 20.2.73 NMAC. NMED was in receipt of DCP's reported 2022 operating hours at the time of its analysis, but the data were still undergoing internal QA/QC checks and had not been certified yet, so NMED excluded them from its analysis. 2016-2021 operating hours for the NO_X units at LRGP are summarized and plotted below; reported 2022 operating hours are included for informational purposes only.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
6	356	683	1449	1075	2441	833	691
7	229	594	2140	1748	2498	514	524
8	0	264	0	0	0	0	0
9	0	284	0	0	0	0	0
10	4385	3886	83	1081	2723	3516	3162
11	6213	4471	718	4607	7492	6723	6597
29	8653	7635	8388	8721	8726	8760	8657
30	8393	8559	7951	8395	8523	186	188
31	8569	8513	8351	8760	8760	8426	8372

[20] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
32B	2350	8374	8642	8162	8747	0	0



As shown above, year-over-year operating hours for the NO_X units at LRGP have been fairly consistent in recent years, although somewhat higher variability was observed in 2020-2021. However, this increased variability was firmly centered around the 2016-2021 average so its effect on the average was negligible, and there was no discernible impact from the pandemic in 2020. Furthermore, in a detailed discussion with NMED on 7/12/23, DCP indicated that it does not expect future utilization of the NO_X units at LRGP to change appreciably. Therefore, NMED determined that 2016-2021 average operating hours are representative for these units.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the NO_X units at LRGP are summarized below.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
6	58.7	1140	33.5
7	58.1	1287	37.4
8	18.1	3825 (1)	34.5
9	18.1	3825 (1)	34.5
10	26.8	2612	35.0
11	9.3	5037	23.4
29	1.1	8481	4.7
30	2.3	7001	7.9

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
31	3.0	8563	12.8
32B	3.8	6046	11.5

(1) Units 8 and 9 have not operated since 2017, skewing their 2016-2021 average operating hours. Therefore, the average 2016-2021 average operating hours of identical Units 10 and 11 were used as a surrogate for these units.

C.4.4.4 Technical Feasibility of Available Controls

As indicated in Section C.3.1, the following determinations were made regarding the technical feasibility of identified control options for the 2SLB RICE at LRGP:

- SCR, SNCR, and NSCR are not technically feasible options.
- GCP is a technically feasible option and is currently utilized by DCP based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- LEC is a technically feasible option expected to achieve a vendor-quoted NO_X emission rate of 0.5 g/hp-hr.
- Unit replacement is a technically feasible option expected to achieve a NO_X emission rate of 0.3 g/hp-hr or 0.5 g/hp-hr depending on the unit, consistent with the emission standards for new natural gas-fired spark ignition engines in 20.2.50 NMAC.[21]
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, DCP did not indicate that it intends to permanently retire any of the affected units, so this option is not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants).

As indicated in Section C.3.4, the following determinations were made regarding the technical feasibility of identified control options for the CT at LRGP:

- WSI, SNCR, and NSCR are not technically feasible options.
- GCP is a technically feasible option and is currently utilized by DCP based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- DLN is a technically feasible option and is already installed or in the process of being installed on all of the CT at LRGP. As a result, DLN is not evaluated further.
- SCR is a technically feasible option expected to achieve an average NO_X control efficiency of 80 percent.
- Unit replacement is a technically feasible option expected, in the case of Units 29, 30, and 31, to achieve a NO_X emission rate of 15 ppm, consistent with the emission standards for new natural

[21] 20.2.50 NMAC contains varying emission standards for new natural gas-fired spark ignition engines based on engine type and rated brake horsepower. See Section 113, Table 2. Equivalent replacements for Units 6 and 7 would be subject to the NO_X standard for new lean burn engines ≥1,875 bhp (0.3 g/bhp-hr), while equivalent replacements for Units 8, 9, 10, and 11 would be subject to the NO_X standard for new lean burn engines >500 and <1,875 bhp (0.5 g/bhp-hr).

gas-fired combustion turbines in 20.2.50 NMAC.[22] In the case of Unit 32B, replacement is expected to achieve a NO_X emission rate of 25 ppm, consistent with manufacturer specifications for similar, new CT equipped with DLN.

- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, DCP did not indicate that it intends to permanently retire any of the affected units, so this option is not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants).

As indicated in Section C.3.6, the following determinations were made regarding the technical feasibility of identified control options for the ATS at LRGP:

- While a flare, SRU, or TO are technically feasible options, the use of an AGI well with redundant compression is an optimal approach to reducing emissions from ATS because emissions are only produced during AGI SSM/M events. Therefore, NMED did not evaluate these options.
- While improved flare design might reduce emissions somewhat during AGI SSM/M events, the potential marginal improvement in combustion efficiency – perhaps 1 to 2 percentage points – from the most optimized flare is not anticipated to be a cost-effective option for reducing SO_2 emissions from acid gas flaring during AGI SSM/M events. Therefore, NMED did not evaluate this option.

C.4.4.5 Four-Factor Analysis

In order to determine what control measures are necessary at LRGP to make reasonable progress, NMED conducted a FFA of potential control measures for NO_X for the NO_X units identified in section C.4.4.2 above. NMED did not conduct a FFA of potential control measures for SO_2 for LRGP's ATS because the most effective control available – an AGI well with redundant compression – is already being utilized at LRGP. States are required to consider four statutory factors – cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[23]

C.4.4.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X emissions reduced, of each technically feasible control option identified in section C.4.4.4 above. NMED utilized source-specific cost estimates provided by DCP in its calculations whenever possible. In cases where DCP failed to provide source-specific cost estimates or NMED found estimates provided by DCP to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs.

[22] 20.2.50 NMAC contains varying emission standards for new natural gas-fired stationary combustion turbines based on rated brake horsepower. See Section 113, Table 3. Equivalent replacements for Units 29, 30 and 31 would be subject to the NO_X standard for new CT ≥4,000 and <15,900 bhp (15 ppm).

[23] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).

Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[24]

NMED's cost effectiveness values for all technically feasible controls for the NO_X units at LRGP are summarized below. NMED believes these values were calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed cost effectiveness calculations for the NO_X units at LRGP and supporting documentation for NMED's cost estimates are provided in Appendix D.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
6	LEC	$475,935	32.2	$15,000
	Replacement	$732,267	32.7	$22,000
	Electrification	$1,169,893	33.5	$35,000
7	LEC	$475,935	36.0	$13,000
	Replacement	$732,267	36.5	$20,000
	Electrification	$1,169,893	37.4	$31,000
8	LEC	$475,935	31.9	$15,000
	Replacement	$463,891	31.9	$15,000
	Electrification	$833,188	34.5	$24,000
9	LEC	$475,935	31.9	$15,000
	Replacement	$463,891	31.9	$15,000
	Electrification	$833,188	34.5	$24,000
10	LEC	$475,935	33.2	$14,000
	Replacement	$463,891	33.2	$14,000
	Electrification	$833,188	35.0	$24,000
11	LEC	$475,935	19.8	$24,000
	Replacement	$463,891	19.8	$23,000
	Electrification	$833,188	23.4	$36,000
29	SCR	$464,471	3.7	$124,000
	Replacement	$2,936,040	-9.3 (1)	-$315,000 (1)
	Electrification	$5,167,169	4.7	$1,106,000
30	SCR	$442,122	6.4	$70,000
	Replacement	$2,716,015	-2.0 (1)	-$1,373,000 (1)
	Electrification	$4,798,769	7.9	$604,000
31	SCR	$281,318	10.3	$27,000
	Replacement	$1,289,421	2.6	$501,000
	Electrification	$2,410,142	12.8	$188,000
32B	SCR	$272,682	9.2	$30,000
	Replacement	$1,086,680	0	N/A (2)

[24]The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
	Electrification	$2,070,681	11.5	$181,000

(1) Negative estimated reductions and cost effectiveness are an artifact of NMED's methods for calculating these values and do not accurately represent the cost effectiveness of the control or its expected emissions impact. Negative values are an indication that the emission rate associated with the control is greater than the current emission rate of the unit in question, which means the control would not be expected to reduce emissions. Controls that would not reduce emissions are not cost-effective on their face and were not considered further.

(2) Because estimated reductions are zero, and division by zero is undefined, cost effectiveness cannot be calculated for replacement of this unit.

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the NO_X units at LRGP:

- DCP did not provide a company-specific cost of capital, so the bank prime rate (7.5 percent as of December 2024) was used to determine the appropriate capital recovery factor.
- In DCP's 8/28/23 submittal, DCP stated that significant electricity infrastructure upgrades, with an estimated capital cost of $28M, would be necessary to support electrification. That submittal also included the estimated Total Capital Costs ($) and Additional Electric Demand ($/yr) associated with electrification. NMED accounted for these costs in its determination of cost effectiveness.
- The Total Capital Costs (TCC), Direct Annual Costs (DAC), and Indirect Annual Costs (OAC) of SCR were calculated using EPA's SCR Tool. An SCR retrofit factor of 1 (average difficulty) was applied, consistent with the SCR evaluations provided in DCP's initial FFA.
- DCP recently upgraded Units 29, 30, and 31 with DLN to comply with 20.2.50 NMAC. Therefore, NMED's SCR and replacement evaluations for these units considered the incremental emissions reductions that would be achieved by adding SCR to these units or replacing them with new natural gas-fired CT. DCP is also in the advanced stages of upgrading Unit 32B with DLN to comply with 20.2.50 NMAC. Therefore, NMED's base case assumes DLN has already been installed on this unit and its SCR and replacement evaluations – like its evaluations for Units 29, 30, and 31 – considered the incremental emissions reductions that would be achieved by adding SCR to this unit or replacing it with a new natural gas-fired CT.
- DCP, like most of the companies required to submit a FFA, did not provide information regarding the TCI associated with the replacement of the 2SLB RICE or CT units at LRGP with new, functionally equivalent natural gas-fired units. NMED reviewed several publicly available resources with information that could be used to estimate the TCI of a replacement RICE or CT[25] along with information provided by other companies with similar units. NMED determined that the most applicable cost metrics ($ per hp basis) were provided by El Paso Natural Gas Company in support of their FFA submittals. NMED understands that the use of these metrics is likely accurate to within ±30 percent, but also recognizes that various preliminary vendor quotes are often caveated with a similar degree of accuracy.

[25] This includes, but is not limited to, the U.S. EPA's Combined Heat and Power Catalog of Technologies (Reciprocating engines) and the U.S. Energy Information Agency's *Cost and Performance Characteristics of New Generating Technologies* in the 2023 Annual Energy Outlook.

C.4.4.5.2 Compliance Time

DCP did not identify any technically feasible control options for the 2SLB RICE at LRGP in its initial FFA submittal,[26] so it did not provide estimated compliance times for any of the control options NMED has determined are technically feasible. NMED's general assessment of compliance times provided in Section C.3.1 are believed to be reasonably accurate.

DCP indicated it would take 13 months to implement DLN on the CT at LRGP, and approximately 9 months to implement SCR. These estimates include a 25 percent contingency factor to account for unforeseen circumstances or setbacks associated with installation of the controls. NMED believes that even with the contingency factor these timeframes are very optimistic based on information provided by other facilities. NMED believes the general compliance times for DLN and SCR provided in Section C.3.4 are more reasonable. NMED also believes the general compliance time for replacement – which DCP did not assess in its initial FFA or follow-up submittals – provided in Section C.3.4 is reasonably accurate.

In its 8/28/23 submittal, DCP estimated that electrification would take 12-14 years. That estimate is based on the following project development timeline: 5 years for construction approval, 3 years to source the electrical equipment, and 4-6 years to complete construction. NMED disagrees with this estimate based on information provided by other facilities and the implementation time of electrification projects at other facilities. NMED believes the general compliance time for electrification, provided in Section C.3.4, is more reasonable but recognizes several more years could be required considering the relative complexity.

C.4.4.5.3 Remaining Useful Life

Despite the advanced age of the 2SLB RICE at LRGP (~50 to 70 years), owners and operators of gas compression equipment in New Mexico have indicated that similar RICE would last at least 20 more years with proper maintenance. Twenty years is thus the estimated remaining useful life for LEC.

Manufacturers of new RICE and CT will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new RICE and CT are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement RICE or CT is 30 years.

Consistent with generally accepted EPA methodology and NMED's experience, the useful life of SCR is estimated to be 20 years.

There is limited information about the useful life of electric compression equipment, but research suggests the useful life is at least 25 years.

[26] DCP implicitly acknowledged the technical feasibility of LEC by providing indicative pricing for LEC retrofits in its 8/28/23 submittal. Prior to that, DCP had maintained that the engines at LRGP were incapable of being retrofit with LEC due to their age.

C.4.4.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for 2SLB RICE and CT is provided in Sections C.3.1 and C.3.4, respectively.

C.4.4.5.5 Summary

NMED performed a FFA for all technically feasible control options for the NO_X units listed in Section C.4.4.2 above. The four statutory factors are discussed in Sections C.4.4.5.1 through C.4.4.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
6	LEC	$15,000	2-3	20	None
	Replacement	$22,000	3-4	30	None
	Electrification	$35,000	4-6	25	None
7	LEC	$13,000	2-3	20	None
	Replacement	$20,000	3-4	30	None
	Electrification	$31,000	4-6	25	None
8	LEC	$15,000	2-3	20	None
	Replacement	$15,000	3-4	30	None
	Electrification	$24,000	4-6	25	None
9	LEC	$15,000	2-3	20	None
	Replacement	$15,000	3-4	30	None
	Electrification	$24,000	4-6	25	None
10	LEC	$14,000	2-3	20	None
	Replacement	$14,000	3-4	30	None
	Electrification	$24,000	4-6	25	None
11	LEC	$24,000	2-3	20	None
	Replacement	$23,000	3-4	30	None
	Electrification	$36,000	4-6	25	None
29	SCR	$124,000	3-4	20	None
	Replacement	-$315,000	3-4	30	None
	Electrification	$1,106,000	4-6	25	None
30	SCR	$70,000	3-4	20	None
	Replacement	-$11,373,000	3-4	30	None
	Electrification	$604,000	4-6	25	None
31	SCR	$27,000	3-4	20	None
	Replacement	$501,000	3-4	30	None
	Electrification	$188,000	4-6	25	None
32B	SCR	$30,000	3-4	20	None
	Replacement	N/A	3-4	30	None
	Electrification	$181,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

C.4.4.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[27]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For emissions units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For emissions units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective control is necessary to make reasonable progress. The sole exception to these general rules is the categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

NMED's FFA did not identify any cost-effective controls for LRGP Units 6, 7, 8, 9, 10, 11, 29, 30, 31, or 32B. Therefore, NMED determined that reasonable progress does not require new controls on any of these units.

As noted above, NMED did not conduct a FFA of potential control measures for LRGP's ATS. Because the most effective control available – an AGI well with redundant compression – is already being utilized at LRGP, NMED determined that reasonable progress does not require new controls for the ATS. Because redundant compression was added to LRGP's AGI well before the start of the second planning period, the resulting emissions reductions were realized during the first planning period. Therefore, NMED did not estimate these reductions.

C.4.5 El Paso Natural Gas Company – Blanco Compressor Station A

Resources used in NMED's FFA for Blanco Compressor Station A (BCSA) include, but are not limited to, the following:

- The initial FFA completed by Alliant Environmental, LLC for El Paso Natural Gas Company, LLC (EPNG), a subsidiary of Kinder Morgan, Inc. (Kinder Morgan), and submitted to NMED on or about 11/1/19.
- Additional information provided by EPNG or Kinder Morgan on 2/14/20, 2/23/20, 9/9/20, 10/9/20, 2/23/21, and 5/26/23.
- The revised FFA submitted to NMED on 6/5/23.

[27] See *supra* note 13.

- Detailed discussions between EPNG and NMED, most recently on 5/3/23.
- EPNG's proposed Part 50 Alternative Compliance Plan (ACP), submitted on 6/13/23 and updated on 8/8/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP region (March 23, 2020).
- FFAs developed for similar facilities in New Mexico and other states.

C.4.5.1 Facility Description

BCSA is a natural gas compressor station located 0.1 miles north of Bloomfield in San Juan County, New Mexico at latitude 36° 43' 42", longitude -107° 57' 21". It is owned and operated by EPNG and currently operates under Title V Operating Permit No. P048-R4, which expires on September 18, 2025. The shortest distance to the boundary of the nearest Class I Area, Mesa Verde National Park, is approximately 39.8 miles.

The function of the facility is to compress natural gas for the purpose of transportation to another facility or a major transportation pipeline. The facility is authorized for continuous operation, and its total potential to emit is 1344 tons per year of NO_X and 0.3 tons per year of SO_2.[28]

C.4.5.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at BCSA. No units met NMED's criteria for requiring an evaluation of potential control measures for SO_2.[29]

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
A01	2SLB RICE	Cooper Bessemer GMV10-TF	<August 1953 (1)	943 hp
A02	2SLB RICE	Cooper Bessemer GMV10-TF	<August 1953 (1)	943 hp
A03	2SLB RICE	Cooper Bessemer GMV10-TF	<August 1953 (1)	943 hp
A04	2SLB RICE	Cooper Bessemer GMV10-TF	<August 1953 (1)	943 hp
A05	2SLB RICE	Cooper Bessemer GMV10-TF	<August 1953 (1)	943 hp
A06	2SLB RICE	Cooper Bessemer GMV10-TF	<August 1953 (1)	943 hp
A07	2SLB RICE	Cooper Bessemer GMV10-TF	<August 1953 (1)	943 hp
A08	2SLB RICE	Cooper Bessemer GMV10-TF	<August 1953 (1)	943 hp
A09	2SLB RICE	Cooper Bessemer GMV10-TF	<August 1953 (1)	943 hp
A10	2SLB RICE	Cooper Bessemer GMV10-TF	<August 1953 (1)	943 hp

[28] AQB Title V Operating Permit No. P048-R4, Table 301.A.

[29] See Chapter 6, Selection of Sources for Control Measures Analysis, for a discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
A11	2SLB RICE	Cooper Bessemer GMV10-TF	<August 1953 (1)	943 hp
A12	2SLB RICE	Cooper Bessemer GMV10-TF	<August 1953 (1)	943 hp
A13	2SLB RICE	Cooper Bessemer GMV10-TF	<August 1953 (1)	943 hp
A14	2SLB RICE	Cooper Bessemer GMV10-TF	<August 1953 (1)	943 hp

(1) According to EPNG's most recent Title V permit application, the date of manufacture of Units A01 through A14 is unknown but they were all constructed/reconstructed in August 1953. The date of manufacture necessarily precedes the construction/reconstruction date.

C.4.5.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. EPNG initially requested a future utilization adjustment for BCSA, but later opted not to apply one in its own projected actual emissions calculations.[30] Therefore, NMED did not apply a future utilization adjustment, and projected actual emissions equal baseline actual emissions for the emissions units at BCSA.

NMED calculated baseline actual emissions for the emissions units at BCSA by multiplying representative annual operating hours by the NO_X emission rates reported in EPNG's most recent periodic emissions test report(s).[31,] Because the emissions units at BCSA operate at varying loads, NMED conservatively adjusted reported emission rates to 100 percent load to represent worst-case emissions.[32] Reported and adjusted emission rates for the emissions units at BCSA are summarized below.

Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr @100% load)
A01	NA (1)	---	---	11.6 (2)
A02	3/28/23	7.8	79%	9.9
A03	3/28/23	7.1	84%	8.4
A04	4/19/22	1.4	61%	2.9
A05	NA (1)	---	---	11.6 (2)
A06	NA (1)	---	---	11.6 (2)
A07	NA (1)	---	---	11.6 (2)
A08	NA (1)	---	---	11.6 (2)
A09	4/19/22	10.8	89%	12.1
A10	NA (1)	---	---	11.6 (2)
A11	3/29/23	13.8	76%	18.1
A12	NA (1)	---	---	11.6 (2)
A13	3/29/23	16.3	90%	18.1
A14	NA (1)	---	---	11.6 (2)

(1) NA = Not Available

(2) The average adjusted emissions of Units A02, A03, A04, A09, A11, and A13 were used as a surrogate for Units A01, A05, A06, A07, A08, A10, A12, and A14, as NMED was unable to locate a recent emissions test report for these units.

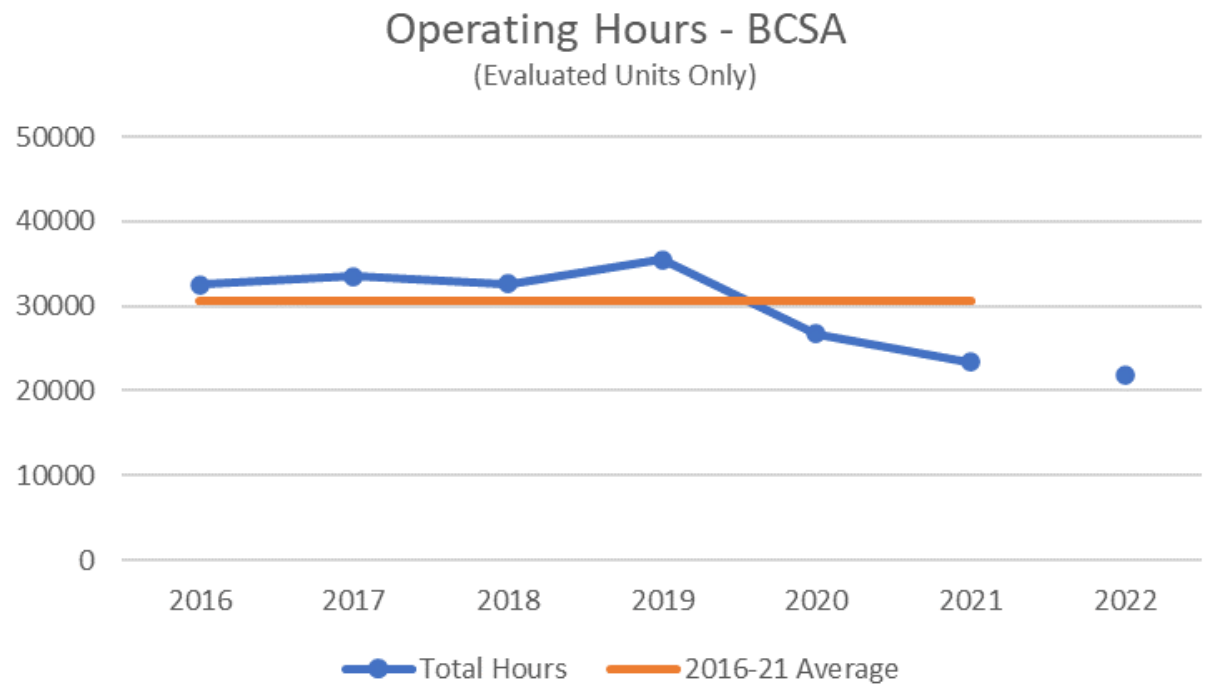
[30] See EPNG's 6/5/23 revised FFA submittal.

[31] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.

[32] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.

To determine representative annual operating hours for the emissions units at BCSA, NMED analyzed 2016-2021 operating hours reported by EPNG pursuant to 20.2.73 NMAC. NMED was in receipt of EPNG's reported 2022 operating hours at the time of its analysis, but the data were still undergoing internal QA/QC checks and had not been certified yet, so NMED excluded them from its analysis. 2016-2021 operating hours for the emissions units at BCSA are summarized and plotted below; reported 2022 operating hours are included for informational purposes only.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
A01	6728	5123	579	3787	2500	0	0
A02	2	14	4	2199	5652	2	2669
A03	5012	5953	3182	5182	225	108	134
A04	99	2	2	511	5055	7980	5243
A05	281	5	9	3	0	1	2
A06	56	5567	2155	2	0	1	1817
A07	5964	6666	1371	3691	2547	1946	1371
A08	1	1	1	2	0	0	0
A09	2499	183	866	3141	2144	5007	4931
A10	1	1	6	2	0	1	0
A11	4404	3239	7450	6581	7642	7076	4897
A12	1	2	3560	3	0	218	0
A13	7490	6827	6108	7130	998	1033	720
A14	1	1	7312	3259	0	1	0



As shown above, operating hours at BCSA were fairly consistent from 2016-2019, then started dropping in 2020. It is unclear whether this was related to the pandemic, or if the lower operating hours observed in 2020-2021 represent future operating conditions better than the higher operating hours observed in 2016-2019. However, NMED notes that EPNG used the highest operating hours from 2015-2019, when total operating hours were considerably higher than they were in 2020-2021, in its own projected actual emissions calculations.[33] Therefore, NMED determined that 2016-2021 average operating hours are representative for the emissions units at BCSA.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the emissions units at BCSA are summarized below.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
A01	11.6	3120	18.1
A02	9.9	1312	6.5
A03	8.4	3277	13.8
A04	2.9	2275	3.2
A05	11.6	50	0.3
A06	11.6	1297	7.5
A07	11.6	3698	21.4
A08	11.6	1	0.005
A09	12.1	2307	14.0
A10	11.6	2	0.011
A11	18.1	6065	54.8
A12	11.6	631	3.7
A13	18.1	4931	44.6
A14	11.6	1762	10.2

C.4.5.4 Technical Feasibility of Available Controls

As indicated in Section C.3.1, the following determinations were made regarding the technical feasibility of identified control options for the 2SLB RICE at BCSA:

- SCR, SNCR, and NSCR are not technically feasible options.
- GCP is a technically feasible option and is currently utilized by EPNG based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- LEC is a technically feasible option. In this case, EPNG indicated that three LEC configurations dubbed LEC1, LEC2, and LEC3 are available that would achieve vendor-quoted, not-to-exceed NO_X emission rates of 3.0 g/bhp-hr, 1.0 g/bhp-hr, and 0.5 g/bhp-hr, respectively.[34]

[33] See EPNG's 6/5/23 revised FFA submittal.

[34] Hoerbiger Engineering Services budgetary estimate included in EPNG's 2/14/20 submittal.

- Unit replacement is a technically feasible option expected to achieve a NO_X emission rate of 0.5 g/hp-hr, consistent with the emissions standards for new natural gas-fired spark ignition lean burn engines in 20.2.50 NMAC.[35]
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). EPNG's initial FFA submittal evaluated a scenario involving the retirement of five units in conjunction with LEC upgrades to the remaining nine units, and its proposed ACP incorporated emission reductions achieved by retiring seven units. Considering that EPNG's proposed ACP was disapproved by NMED and EPNG always has the option of retiring a unit, this option was not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants).

C.4.5.5 Four-Factor Analysis

In order to determine what control measures are necessary at BCSA to make reasonable progress, NMED conducted a FFA of potential control measures for NO_X for the emissions units identified in section C.4.5.2 above. States are required to consider four statutory factors – cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[36]

C.4.5.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X emissions reduced, of each technically feasible control option identified in section C.4.5.4 above. NMED utilized source-specific cost estimates provided by EPNG in its calculations whenever possible. In cases where EPNG failed to provide source-specific cost estimates or NMED found estimates provided by EPNG to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[37]

NMED's cost effectiveness values for all technically feasible controls for the emissions units at BCSA are summarized below. NMED believes these values were calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed cost effectiveness calculations for the emissions units at BCSA and supporting documentation for NMED's cost estimates are provided in Appendix D.

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[35] 20.2.50 NMAC contains varying emission standards for new natural gas-fired spark ignition engines based on engine type and rated brake horsepower. See Section 113, Table 2. Equivalent replacements for the 2SLB RICE at BCSA would be subject to the NO_X standard for new lean burn engines >500 and <1,875 bhp (0.5 g/bhp-hr).

[36] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).

[37] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
A01	LEC1	$396,254	8.3	$48,000
	LEC2	$625,478	14.8	$42,000
	LEC3	$589,702	16.4	$36,000
	Replacement	$380,474	16.4	$23,000
A02	LEC1	$396,254	2.4	$164,000
	LEC2	$625,478	5.1	$122,000
	LEC3	$589,702	5.8	$101,000
	Replacement	$380,474	5.8	$65,000
A03	LEC1	$396,254	3.6	$111,000
	LEC2	$625,478	10.4	$60,000
	LEC3	$589,702	12.1	$49,000
	Replacement	$380,474	12.1	$31,000
A04	LEC1	$396,254	-3.8 (2)	-$103,000 (2)
	LEC2	$625,478	0.9	$711,000
	LEC3	$589,702	2.1	$286,000
	Replacement	$380,474	2.1	$185,000
A05	LEC1	$396,254	0.1	$2,975,000
	LEC2	$625,478	0.2	$2,641,000
	LEC3	$589,702	0.3	$2,245,000
	Replacement	$380,474	0.3	$1,448,000
A06	LEC1	$396,254	3.5	$114,000
	LEC2	$625,478	6.2	$101,000
	LEC3	$589,702	6.8	$86,000
	Replacement	$380,474	6.8	$56,000
A07	LEC1	$396,254	9.9	$40,000
	LEC2	$625,478	17.6	$36,000
	LEC3	$589,702	19.5	$30,000
	Replacement	$380,474	19.5	$20,000
A08	LEC1	$396,254	0.002	$177,879,000
	LEC2	$625,478	0.004	$157,945,000
	LEC3	$589,702	0.004	$134,231,000
	Replacement	$380,474	0.004	$86,605,000
A09	LEC1	$396,254	6.8	$58,000
	LEC2	$625,478	11.6	$54,000
	LEC3	$589,702	12.8	$46,000
	Replacement	$380,474	12.8	$30,000
A10	LEC1	$396,254	0.005	$80,854,000
	LEC2	$625,478	0.009	$71,793,000
	LEC3	$589,702	0.010	$61,014,000
	Replacement	$380,474	0.010	$39,366,000
A11	LEC1	$396,254	35.9	$11,000

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
	LEC2	$625,478	48.5	$13,000
	LEC3	$589,702	51.7	$11,000
	Replacement	$380,474	51.7	$7,000
A12	LEC1	$396,254	1.7	$235,000
	LEC2	$625,478	3.0	$209,000
	LEC3	$589,702	3.3	$177,000
	Replacement	$380,474	3.3	$114,000
A13	LEC1	$396,254	29.2	$14,000
	LEC2	$625,478	39.5	$16,000
	LEC3	$589,702	42.1	$14,000
	Replacement	$380,474	42.1	$9,000
A14	LEC1	$396,254	4.7	$84,000
	LEC2	$625,478	8.4	$75,000
	LEC3	$589,702	9.3	$63,000
	Replacement	$380,474	9.3	$41,000
All Units	Electrification [1]	$3,916,630	198.1	$20,000

[1] Electrification was evaluated at the station level instead of unit by unit for EPNG's facilities.
[2] Negative estimated reductions and cost effectiveness are an artifact of NMED's methods for calculating these values and do not accurately represent the cost effectiveness of the control or its expected emissions impact. Negative values are an indication that the emission rate associated with the control is greater than the current emission rate of the unit in question, which means the control would not be expected to reduce emissions. Controls that would not reduce emissions are not cost-effective on their face and are excluded from further consideration.

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the emissions units at BCSA:

- EPNG provided a company-specific cost of capital (8.53 percent) in its 2/23/20 submittal.
- The calculated cost effectiveness of each LEC configuration is based on a Total Capital Cost (TCC) estimate provided by a vendor.
- EPNG provided a Total Capital Investment (TCI) cost metric of $3,227/hp (2020$) for the installation of new, replacement RICE at BCSA. The cost metric was developed by Kinder Morgan's Cost Estimating Group based on its extensive industry experience. NMED reviewed several publicly available resources along with information provided by other companies with similar units that could be used to estimate the TCI of a replacement RICE, and determined that the Kinder Morgan metric was reasonable. NMED understands that the use of this metric is likely accurate to within ±30 percent, but also recognizes that various preliminary vendor quotes are often caveated with a similar degree of accuracy.
- On 2/14/20, EPNG provided a $1,469/hp (2020$) all-in TCC metric for electrification. On 9/9/20, EPNG provided an alternate cost estimate developed using "the [Kinder Morgan] Cost Estimating Group's Developmental Cost Estimating Tool." The alternate estimate applied an unusual and insufficiently documented methodology that involved a base cost estimate for replacement RICE that was adjusted using EMD-specific costs and RICE-specific costs. Using detailed cost information provided by other facilities, NMED developed a TCC metric of $2,084/hp (2023$) for replacement with EMD. Costs associated with requisite substation and utility line upgrades were estimated separately and added to TCC to estimate TCI for electrification.

C.4.5.5.2 Compliance Time

EPNG estimated that LEC retrofits could be completed in 1-3 years after the issuance of a revised permit by NMED. This estimate is based, in part, on EPNG's assertion that the units could not be simultaneously retrofitted because the facility must maintain a minimum active compression capacity to maintain pressure within the transmission pipeline. Based on information provided by other facilities and other resources, NMED believes this timeframe is reasonable.

EPNG did not provide an estimate of the time necessary to replace the units at BCSA. NMED believes the general compliance times for replacement with like-kind natural gas-fired engines or EMD provided in Section C.3.1 are reasonable but recognizes that in the case of EMD several more years could be required considering the relative complexity.

C.4.5.5.3 Remaining Useful Life

Despite the advanced age of the units at BCSA (~70 years), owners and operators of gas compression equipment in New Mexico have indicated that similar RICE would last at least 20 more years with proper maintenance. Twenty years is thus the estimated remaining useful life for LEC.

Manufacturers of new RICE will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new RICE are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement RICE is 30 years.

There is limited information about the useful life of EMD units, but research suggests the useful life is at least 25 years.

C.4.5.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for 2SLB RICE is provided in Section C.3.1.

C.4.5.5.5 Summary

NMED performed a FFA for all technically feasible control options for NO_X for the units listed in Section C.4.5.2 above. The four statutory factors are discussed in Sections C.4.5.5.1 through C.4.5.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
A01	LEC1	$48,000	1-3	20	None
	LEC2	$42,000	1-3	20	None
	LEC3	$36,000	1-3	20	None
	Replacement	$23,000	3-4	30	None
A02	LEC1	$164,000	1-3	20	None
	LEC2	$122,000	1-3	20	None
	LEC3	$101,000	1-3	20	None

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [1]
	Replacement	$65,000	3-4	30	None
A03	LEC1	$111,000	1-3	20	None
	LEC2	$60,000	1-3	20	None
	LEC3	$49,000	1-3	20	None
	Replacement	$31,000	3-4	30	None
A04	LEC1	-$103,000	1-3	20	None
	LEC2	$711,000	1-3	20	None
	LEC3	$286,000	1-3	20	None
	Replacement	$185,000	3-4	30	None
A05	LEC1	$2,975,000	1-3	20	None
	LEC2	$2,641,000	1-3	20	None
	LEC3	$2,245,000	1-3	20	None
	Replacement	$1,448,000	3-4	30	None
A06	LEC1	$114,000	1-3	20	None
	LEC2	$101,000	1-3	20	None
	LEC3	$86,000	1-3	20	None
	Replacement	$56,000	3-4	30	None
A07	LEC1	$40,000	1-3	20	None
	LEC2	$36,000	1-3	20	None
	LEC3	$30,000	1-3	20	None
	Replacement	$20,000	3-4	30	None
A08	LEC1	$177,879,000	1-3	20	None
	LEC2	$157,945,000	1-3	20	None
	LEC3	$134,231,000	1-3	20	None
	Replacement	$86,605,000	3-4	30	None
A09	LEC1	$58,000	1-3	20	None
	LEC2	$54,000	1-3	20	None
	LEC3	$46,000	1-3	20	None
	Replacement	$30,000	3-4	30	None
A10	LEC1	$80,854,000	1-3	20	None
	LEC2	$71,793,000	1-3	20	None
	LEC3	$61,014,000	1-3	20	None
	Replacement	$39,366,000	3-4	30	None
A11	LEC1	$11,000	1-3	20	None
	LEC2	$13,000	1-3	20	None
	LEC3	$11,000	1-3	20	None
	Replacement	$7,000	3-4	30	None
A12	LEC1	$235,000	1-3	20	None
	LEC2	$209,000	1-3	20	None
	LEC3	$177,000	1-3	20	None

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
	Replacement	$114,000	3-4	30	None
A13	LEC1	$14,000	1-3	20	None
	LEC2	$16,000	1-3	20	None
	LEC3	$14,000	1-3	20	None
	Replacement	$9,000	3-4	30	None
A14	LEC1	$84,000	1-3	20	None
	LEC2	$75,000	1-3	20	None
	LEC3	$63,000	1-3	20	None
	Replacement	$41,000	3-4	30	None
All Units	Electrification	$20,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

C.4.5.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[38]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For emissions units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For emissions units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective control is necessary to make reasonable progress. The sole exception to these general rules is the categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

NMED's FFA identified cost-effective controls for BCSA Units A11 and A13. Based on its analysis of the four statutory factors and the decision-making criteria described above, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

[38] See *supra* note 13.

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
A11	Replacement	51.7
A13	Replacement	42.1

NMED did not identify any cost-effective controls for BCSA Units A01, A02, A03, A04, A05, A06, A07, A08, A09, A10, A12, or A14. Therefore, NMED determined that reasonable progress does not require new controls on any of these units.

Based on the expected reductions from the controls NMED has determined are necessary to make reasonable progress, NMED estimates the total emissions reductions at BCSA during the second planning period will be approximately 93.8 ton/yr of NO_X.

C.4.6 El Paso Natural Gas Company – Pecos River Compressor Station

Resources used in NMED's FFA for Pecos River Compressor Station (PRCS) include, but are not limited to, the following:

- The FFA completed by Trinity Consultants for El Paso Natural Gas Company, LLC (EPNG), a subsidiary of Kinder Morgan, Inc. (Kinder Morgan), and submitted to NMED on or about 11/1/19.
- Additional information provided by EPNG or Kinder Morgan on 2/14/20, 2/23/20, 9/9/20, 10/9/20, 2/23/21, and 5/26/2023.
- Detailed discussions between EPNG and NMED, most recently on 5/3/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP region (March 23, 2020)
- FFAs developed for similar facilities in New Mexico and other states.

C.4.6.1 Facility Description

PRCS is a natural gas compressor station located approximately 11.5 miles south-southeast of Malaga in Eddy County, New Mexico at latitude 32° 03' 49", longitude -104° 01' 06". It is owned and operated by EPNG and currently operates under Title V Operating Permit No. P129-R4, which expires on March 4, 2026. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 22.1 miles.

The function of the facility is to compress natural gas and deliver the compressed gas to a pipeline for mainline transportation. The facility is authorized for continuous operation, and its total potential to emit is 697.7 tons per year of NO_X and 5.6 tons per year of SO_2.[39]

[39] AQB Title V Operating Permit No. P129-R4, Table 102.A.

C.4.6.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at PRCS. No units met NMED's criteria for requiring an evaluation of potential control measures for SO_2.[40]

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
A-01	Turbine	General Electric M3712-R, Frame 3	1953	7,150 hp
A-02	Turbine	General Electric M3712-R, Frame 3	1953	7,150 hp
A-03	Turbine	General Electric M3712-R, Frame 3	1953	7,150 hp

C.4.6.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. EPNG did not request a future utilization adjustment for PRCS. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the emissions units at PRCS.

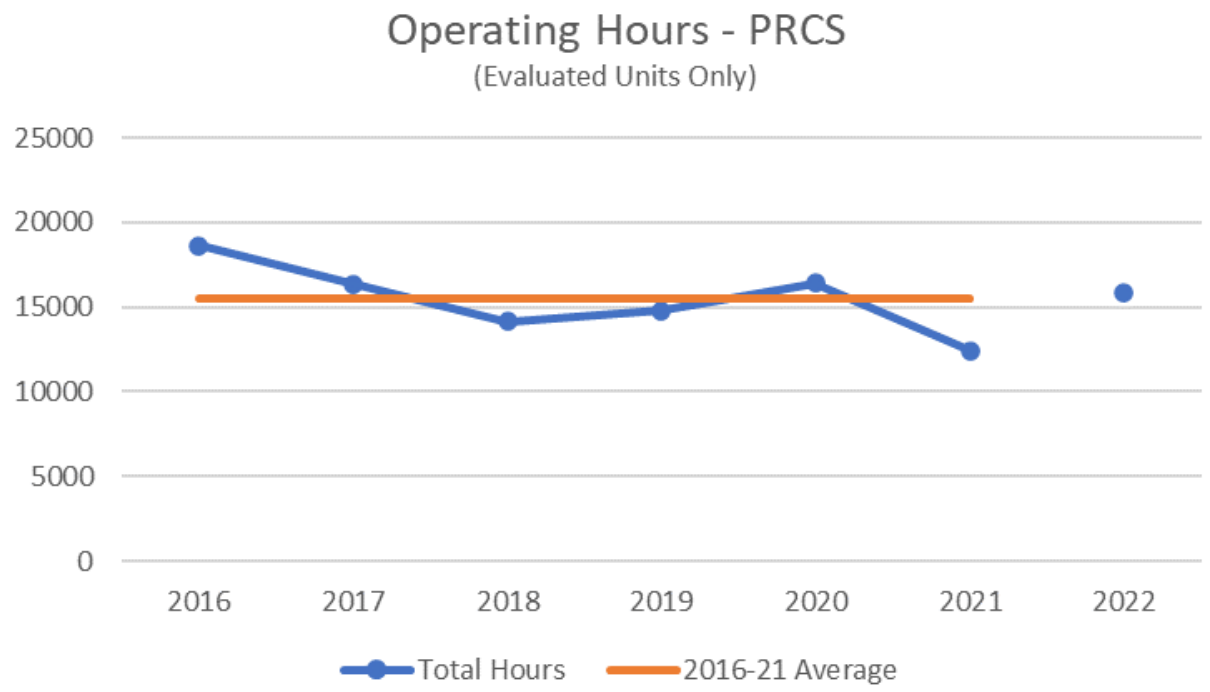
NMED calculated baseline actual emissions for the emissions units at PRCS by multiplying representative annual operating hours by the NO_X emission rates reported in EPNG's most recent periodic emissions test report(s).[41,] Because the emissions units at PRCS operate at varying loads, NMED conservatively adjusted reported emission rates to 100 percent load to represent worst-case emissions.[42] Reported and adjusted emission rates for the emissions units at PRCS are summarized below.

Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr at 100% load)
A-01	6/20/23	22.4	57%	39.5
A-02	6/8/22	25.3	70%	36.4
A-03	6/20/23	24.4	60%	40.5

To determine representative annual operating hours for the emissions units at PRCS, NMED analyzed 2016-2021 operating hours reported by EPNG pursuant to 20.2.73 NMAC. NMED was in receipt of EPNG's reported 2022 operating hours at the time of its analysis, but the data were still undergoing internal QA/QC checks and had not been certified yet, so NMED excluded them from its analysis. 2016-2021 operating hours for the emissions units at PRCS are summarized and plotted below; reported 2022 operating hours are included for informational purposes only.

[40] See Chapter 6, Selection of Sources for Control Measures Analysis, for a discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.
[41] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.
[42] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
A-01	4982	754	5323	2700	4737	2820	6998
A-02	7166	7916	3813	6738	7344	5293	3827
A-03	6501	7693	5031	5356	4333	4305	5069



As shown above, PRCS' year-over-year operating hours have been fairly consistent in recent years, although somewhat higher variability was observed in 2016 and 2021. However, this increased variability was firmly centered around the 2016-2021 average so its effect on the average is negligible, and there was no discernible impact from the pandemic in 2020. Therefore, NMED determined that 2016-2021 average operating hours are representative for the emissions units at PRCS.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the emissions units at PRCS are summarized below.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
A-01	39.5	3553	70.1
A-02	36.4	6378	116.0
A-03	40.5	5537	112.2

C.4.6.4 Technical Feasibility of Available Controls

As indicated in Section C.3.4, the following determinations were made regarding the technical feasibility of identified control options for the CT at PRCS:

- SNCR and NSCR are not technically feasible options.
- Neither WSI nor DLN is available for the make and model of CT at PRCS and thus are not technically feasible options.
- GCP is a technically feasible option and is currently utilized by EPNG based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- SCR is a technically feasible option expected to achieve an average NO_X control efficiency of 80 percent.[43]
- Unit replacement is a technically feasible option expected to achieve a NO_X emission rate of 15 ppm, consistent with the emissions standards for new natural gas-fired combustion turbines in 20.2.50 NMAC.[44]
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, EPNG did not indicate that it intends to permanently retire any of the affected units, so this option is not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and other pollutants).

C.4.6.5 Four-Factor Analysis

In order to determine what control measures are necessary at PRCS to make reasonable progress, NMED conducted a FFA of potential control measures for NO_X for the emissions units identified in section C.4.6.2 above. States are required to consider four statutory factors – cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[45]

C.4.6.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X emissions reduced, of each technically feasible control option identified in section C.4.6.4 above. NMED utilized source-specific cost estimates provided by EPNG in its calculations whenever possible. In cases where EPNG failed to provide source-specific cost estimates or NMED found estimates provided by EPNG to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[46]

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[43] EPNG assumed a NOX control efficiency of 70% in the SCR evaluations provided in its initial FFA and 2/14/20 follow-up submittal. While NMED disagrees with this assumption, NMED notes that in its own evaluation, SCR remains cost effective for Units A-02 and A-03 even if the control efficiency is reduced to 70%.

[44] 20.2.50 NMAC contains varying emission standards for new natural gas-fired stationary combustion turbines based on rated brake horsepower. See Section 113, Table 3. Equivalent replacements for the CT at PRCS would be subject to the NO_X standard for new CT ≥4,000 and <15,900 bhp (15 ppm).

[45] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).

[46] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

NMED's cost effectiveness values for all technically feasible controls for the emissions units at PRCS are summarized below. NMED believes these values were calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed cost effectiveness calculations for the emissions units at PRCS and supporting documentation for NMED's cost estimates are provided in Appendix D.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
A-01	SCR	$752,125	56.1	$13,000
	Replacement	$2,250,734	58.9	$38,000
A-02	SCR	$769,297	92.8	$8,000
	Replacement	$2,250,734	100.0	$23,000
A-03	SCR	$765,788	89.8	$9,000
	Replacement	$2,250,734	94.2	$24,000
All Units	Electrification [(1)]	$8,363,225	298.3	$28,000

[(1)] Electrification was evaluated at the station level instead of unit by unit for EPNG's facilities.

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the emissions units at PRCS:

- EPNG provided a company-specific cost of capital (8.53 percent) in its 2/23/20 submittal.
- The Total Capital Costs (TCC), Direct Annual Costs (DAC) and Indirect Annual Costs (OAC) of SCR were calculated using EPA's SCR Tool. In addition to TCC, NMED included EPNG's $3,275,000 estimate (2024$) for turbine housing reconfiguration in the Total Capital Investment (TCI) of SCR.[47] An SCR retrofit factor of 1 (average difficulty) was applied, consistent with the revised SCR evaluations provided in EPNG's 2/14/20 submittal.
- EPNG provided a TCI cost metric of $2,418/hp (2020$) for the installation of new, replacement CT at PRCS. The cost metric was developed by Kinder Morgan's Cost Estimating Group based on its extensive industry experience. NMED reviewed several publicly available resources along with information provided by other companies with similar units that could be used to estimate the TCI of a replacement CT, and determined that the Kinder Morgan metric was reasonable. NMED understands that the use of this metric is likely accurate to within ±30 percent, but also recognizes that various preliminary vendor quotes are often caveated with a similar degree of accuracy.
- On 2/14/20, EPNG provided a $1,469/hp ($2020) all-in TCC metric for electrification. On 9/9/20, EPNG provided an alternate cost estimate developed using "the [Kinder Morgan Cost Estimating Group's Developmental Cost Estimating Tool." The alternate estimate applied an unusual and insufficiently documented methodology that involved a base cost estimate for replacement CT that was adjusted using EMD-specific costs and CT-specific costs. Using detailed cost information provided by other facilities, NMED developed a TCC metric of $2,084/hp (2023$) for replacement with EMD. Costs associated with requisite substation and utility line upgrades were estimated separately and added to TCC to estimate TCI for electrification.

[47] EPNG's initial FFA submittal included $2,500,000 (2019$) to modify the exhaust system ducting and the building that houses the turbines to facilitate installation of SCR module and reagent storage systems. NMED adjusted this for inflation using the Chemical Engineering Plant Cost Index.

C.4.6.5.2 Compliance Time

EPNG estimated that SCR upgrades, including necessary building modifications and SCR control equipment installation, would take approximately 3 years. This estimate is consistent with NMED's general assessment of compliance times and thus believed to be reasonably accurate.

EPNG did not provide an estimate of the time necessary to replace the units at PRCS. NMED believes the general compliance times for replacement with like-kind natural gas-fired CT or EMD provided in Section C.3.4 are reasonable but recognizes that in the case of EMD several more years could be required considering the relative complexity.

C.4.6.5.3 Remaining Useful Life

Consistent with generally accepted EPA methodology and NMED's experience, the useful life of SCR is estimated to be 20 years.

Manufacturers of new CT will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new CT are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement CT is 30 years.

There is limited information about the useful life of EMD units, but research suggests the useful life is at least 25 years.

C.4.6.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for CT is provided in Section C.3.4.

C.4.6.5.5 Summary

NMED performed a FFA for all technically feasible control options for NO_X for the units listed in Section C.4.6.2 above. The four statutory factors are discussed in Sections C.4.6.5.1 through C.4.6.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
A-01	SCR	$13,000	3	20	None
	Replacement	$38,000	3-4	30	None
A-02	SCR	$8,000	3	20	None
	Replacement	$23,000	3-4	30	None
A-03	SCR	$9,000	3	20	None
	Replacement	$24,000	3-4	30	None
All Units	Electrification	$28,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

C.4.6.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[48]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For emissions units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For emissions units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective control is necessary to make reasonable progress. The sole exception to these general rules is the categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

NMED's FFA identified cost-effective controls for PRCS Units A-02 and A-03. Based on its analysis of the four statutory factors and the decision-making criteria described above, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
A-02	SCR	92.8
A-03	SCR	89.8

NMED's FFA did not identify any cost-effective controls for PRCS Unit A-01. Therefore, NMED determined that reasonable progress does not require new controls on this unit.

Based on the expected reductions from the controls NMED has determined are necessary to make reasonable progress, NMED estimates the total emissions reductions at PRCS during the second planning period will be approximately 182.6 ton/yr of NO_X.

C.4.7 El Paso Natural Gas Company – Washington Ranch Storage Facility

Resources used in NMED's FFA for Washington Ranch Storage Facility (WRSF) include, but are not limited to, the following:

[48] See *supra* note 13.

- The FFA completed by Trinity Consultants for El Paso Natural Gas Company, LLC (EPNG), a subsidiary of Kinder Morgan, Inc. (Kinder Morgan), and submitted to NMED on or about 11/1/19.
- Additional information provided by EPNG or Kinder Morgan on 2/14/20, 2/23/20, 9/9/20, 10/9/20, 2/23/21, and 5/26/23.
- Detailed discussions between EPNG and NMED, most recently on 5/3/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP region (March 23, 2020)
- FFAs developed for similar facilities in New Mexico and other states.

C.4.7.1 Facility Description

WRSF is a natural gas storage facility located 9.1 miles southwest of Whites City in Eddy County, New Mexico at latitude 32° 04' 54", longitude -104° 29' 04". It is owned and operated by EPNG and currently operates under Title V Operating Permit No. P064-R4M2, which expires on December 30, 2025. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 3.4 miles.

The function of the facility is to compress and inject natural gas into underground storage wells and to withdraw the gas for delivery into the pipeline. The facility is authorized for continuous operation, and its total potential to emit is 243.6 tons per year of NO_X and 4.8 tons per year of SO_2.[49]

C.4.7.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at WRSF. No units met NMED's criteria for requiring an evaluation of potential control measures for SO_2.[50]

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
1	2SLB RICE	Cooper Bessemer 12Q155HC2	<June 1982 (1)	4,500 hp
2	2SLB RICE	Cooper Bessemer 12Q155HC2	<June 1982 (1)	4,500 hp

(1) According to EPNG's most recent Title V permit application, the date of manufacture of Units 1 and 2 is unknown but both were constructed/ reconstructed in June 1982. The date of manufacture necessarily precedes the construction/reconstruction date.

[49] AQB Title V Operating Permit No. P064-R4M2, Table 102.A.

[50] See Chapter 6, Selection of Sources for Control Measures Analysis, for a discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.

C.4.7.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. EPNG did not request a future utilization adjustment for WRSF. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the emissions units at WRSF.

NMED calculated baseline actual emissions for the emissions units at WRSF by multiplying representative annual operating hours by the NO_X emission rates reported in EPNG's most recent periodic emissions test report(s).[51,] Because the emissions units at WRSF operate at varying loads, NMED conservatively adjusted reported emission rates to 100 percent load to represent worst-case emissions.[52] Reported and adjusted emission rates for the emissions units at WRSF are summarized below.

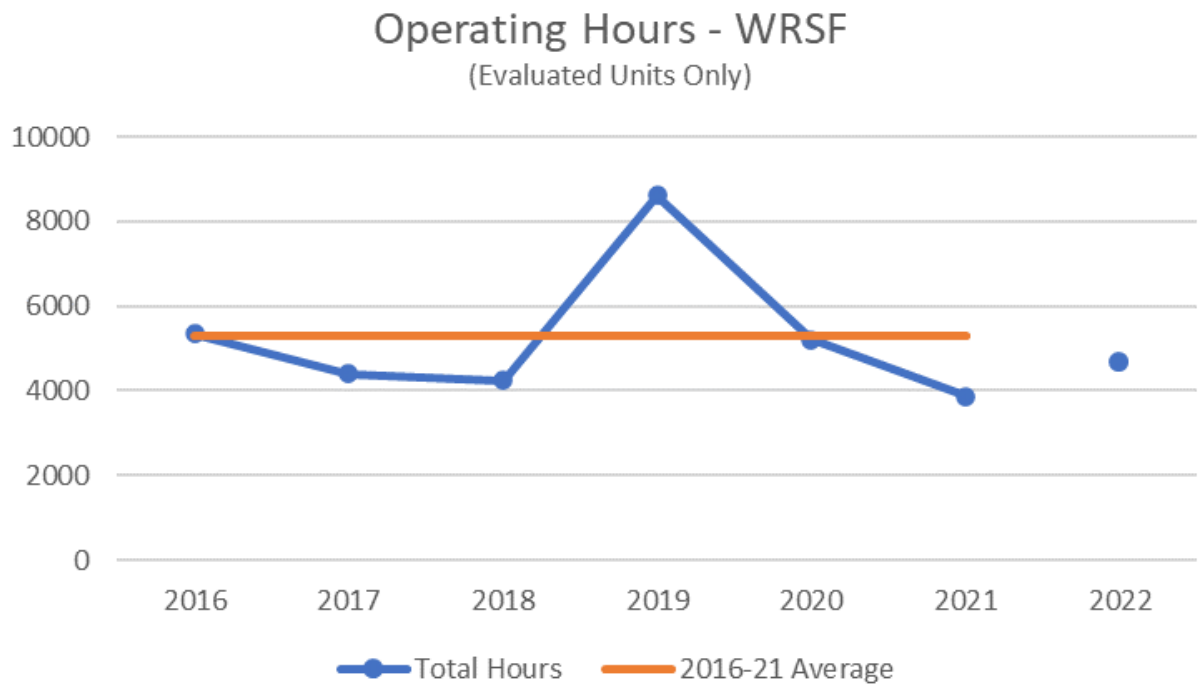
Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr at 100% load)
1	5/26/23	6.8	94%	7.3
2	5/26/23	3.9	93%	4.2

To determine representative annual operating hours for the emissions units at WRSF, NMED analyzed 2016-2021 operating hours reported by EPNG pursuant to 20.2.73 NMAC. NMED was in receipt of EPNG's reported 2022 operating hours at the time of its analysis, but the data were still undergoing internal QA/QC checks and had not been certified yet, so NMED excluded them from its analysis. 2016-2021 operating hours for the emissions units at WRSF are summarized and plotted below; reported 2022 operating hours are included for informational purposes only.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
1	2847	2183	2195	4461	2564	1798	2362
2	2502	2212	2054	4153	2647	2076	2323

[51] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.

[52] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.



As shown above, WRSF's year-over-year operating hours have been fairly consistent in recent years save for a transient spike in 2019, and there was no discernible impact from the pandemic in 2020. Therefore, NMED determined that 2016-2021 average operating hours are representative for the emissions units at WRSF.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the emissions units at WRSF are summarized below.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
1	7.3	2675	9.7
2	4.2	2607	5.5

C.4.7.4 Technical Feasibility of Available Controls

As indicated in Section C.3.1, the following determinations were made regarding the technical feasibility of identified control options for the 2SLB RICE at WRSF:

- SCR, SNCR, and NSCR are not technically feasible options.
- GCP is technically feasible and is currently utilized by EPNG based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- LEC is a technically feasible option and is already installed on both units, resulting in controlled NO_X emission rates of 0.5 and 0.8 g/hp-hr, respectively. As a result, LEC is not evaluated further.

- Unit replacement is a technically feasible option expected to achieve a NO_X emission rate of 0.3 g/hp-hr, consistent with the emissions standards for new natural gas-fired spark ignition lean burn engines in 20.2.50 NMAC.[53]
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, EPNG did not indicate that it intends to permanently retire any of the affected units, so this option is not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and other pollutants).

C.4.7.5 Four-Factor Analysis

In order to determine what control measures are necessary at WRSF to make reasonable progress, NMED conducted a FFA of potential control measures for NO_X for the emissions units identified in section C.4.7.2 above. States are required to consider four statutory factors – cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[54]

C.4.7.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X emissions reduced, of each technically feasible control option identified in section C.4.7.4 above. NMED utilized source-specific cost estimates provided by EPNG in its calculations whenever possible. In cases where EPNG failed to provide source-specific cost estimates or NMED found estimates provided by EPNG to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[55]

NMED's cost effectiveness values for all technically feasible controls for the emissions units at WRSF are summarized below. NMED believes these values were calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed cost effectiveness calculations for the emissions units at WRSF and supporting documentation for NMED's cost estimates are provided in Appendix D.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
1	Replacement	$1,815,624	5.8	$316,000
2	Replacement	$1,815,624	1.6	$1,136,000

[53] 20.2.50 NMAC contains varying emission standards for new natural gas-fired spark ignition engines based on engine type and rated brake horsepower. See Section 113, Table 2. Equivalent replacements for the 2SLB RICE at WRSF would be subject to the NO_X standard for new lean burn engines ≥1,875 bhp (0.3 g/bhp-hr).
[54] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).
[55] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
All Units	Electrification [(1)]	$3,636,702	15.2	$239,000

[(1)] Electrification was evaluated at the station level instead of unit by unit for EPNG's facilities.

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the emissions units at WRSF:

- EPNG provided a company-specific cost of capital (8.53 percent) in its 2/23/20 submittal.
- EPNG provided a Total Capital Investment (TCI) cost metric of $3,227/hp (2020$) for the installation of new, replacement RICE at WRSF. The cost metric was developed by Kinder Morgan's Cost Estimating Group based on its extensive industry experience. NMED reviewed several publicly available resources along with information provided by other companies with similar units that could be used to estimate the TCI of a replacement RICE, and determined that the Kinder Morgan metric was reasonable. NMED understands that the use of this metric is likely accurate to within ±30 percent, but also recognizes that various preliminary vendor quotes are often caveated with a similar degree of accuracy.
- On 2/14/20, EPNG provided a $1,469/hp ($2020) all-in TCC metric for electrification. On 9/9/20, EPNG provided an alternate cost estimate developed using "the [Kinder Morgan] Cost Estimating Group's Developmental Cost Estimating Tool." The alternate estimate applied an unusual and insufficiently documented methodology that involved a base cost estimate for replacement RICE that was adjusted using EMD-specific costs and RICE-specific costs. Using detailed cost information provided by other facilities, NMED developed a TCC metric of $2,084/hp (2023$) for replacement with EMD. Costs associated with requisite substation and utility line upgrades were estimated separately and added to TCC to estimate TCI for electrification.

C.4.7.5.2 Compliance Time

EPNG did not provide an estimate of the time necessary to replace the units at WRSF. NMED believes the general compliance times for replacement with like-kind natural gas-fired engines or EMD provided in Section C.3.1 are reasonable but recognizes that in the case of EMD several more years could be required considering the relative complexity.

C.4.7.5.3 Remaining Useful Life

Manufacturers of new RICE will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new RICE are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement RICE is 30 years.

There is limited information about the useful life of EMD units, but research suggests the useful life is at least 25 years.

C.4.7.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for 2SLB RICE is provided in Section C.3.1.

C.4.7.5.5 Summary

NMED performed a FFA for all technically feasible control options for NO_X for the units listed in Section C.4.7.2 above. The four statutory factors are discussed in Sections C.4.7.5.1 through C.4.7.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
1	Replacement	$316,000	3-4	30	None
2	Replacement	$1,136,000	3-4	30	None
All Units	Electrification	$239,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

C.4.7.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[56]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For emissions units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For emissions units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective control is necessary to make reasonable progress. The sole exception to these general rules is the categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

NMED's FFA did not identify any cost-effective controls for WRSF Units 1 and 2. Therefore, NMED determined that reasonable progress does not require new controls on either of these units.

C.4.8 Enterprise Field Services – Blanco C&D Compressor Station

Resources used in NMED's FFA for Blanco C & D Compressor Station (BCDCS) include, but are not limited to, the following:

[56] See *supra* note 13.

- The FFA completed by Trinity Consultants for Enterprise Field Services, LLC (Enterprise) and submitted to NMED on 11/14/19.
- Additional information provided by Enterprise on 2/14/20, 2/26/20, 5/19/20, 6/2/20, 9/8/20, 10/1/20, 3/4/21, 8/30/23, and 9/20/24.
- Detailed discussions between Enterprise and NMED on 8/28/20 and 7/13/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP region (March 23, 2020)
- FFAs developed for similar facilities in New Mexico and other states.

C.4.8.1 Facility Description

BCDCS is a natural gas compressor station located 2 miles northeast of Bloomfield in San Juan County, New Mexico at latitude 36° 43' 57", longitude -107° 57' 42". It is owned by Enterprise and operated by Enterprise Products Operating, LLC, and currently operates under Title V Operating Permit No. P218-R3, which expires on October 28, 2025. The shortest distance to the boundary of the nearest Class I Area, Mesa Verde National Park, is approximately 40 miles.

The function of the facility is to compress natural gas for the purpose of transportation to another facility or a major transportation pipeline. The facility is authorized for continuous operation, and its total potential to emit is 1332.6 tons per year of NO_X and 4.0 tons per year of SO_2.[57]

C.4.8.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at BCDCS. No units met NMED's criteria for requiring an evaluation of potential control measures for SO_2.[58]

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
T-C01	Turbine	General Electric 5221W	<June 1989 (1)	22,280 hp
T-C02	Turbine	General Electric 5221W	<June 1989 (1)	22,280 hp
T-D01	Turbine	General Electric M5322B	<October 1987 (1)	32,550 hp

(1) According to Enterprise's most recent Title V permit application, the date of manufacture of Units T-C01, T-C02, and T-D01 is unknown but Units T-C01 and T-C02 were constructed/reconstructed prior to June 1989 and Unit T-D01 was constructed/reconstructed prior to October 1987. The date of manufacture necessarily precedes the construction/reconstruction date.

[57] AQB Title V Operating Permit No. P218-R3, Table 401.A.

[58] See Chapter 6, Selection of Sources for Control Measures Analysis, for a detailed discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.

C.4.8.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. Enterprise did not request a future utilization adjustment for BCDCS. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the emissions units at BCDCS.

NMED calculated baseline actual emissions for the emissions units at BCDCS by multiplying representative annual operating hours by the NO_X emission rates reported in Enterprise's most recent periodic emissions test report(s).[59,] Because the emissions units at BCDCS operate at varying loads, NMED conservatively adjusted reported emission rates to 100 percent load to represent worst-case emissions.[60,61] Reported and adjusted emission rates for the emissions units at BCDCS are summarized below.

Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr @ 100% load)
T-C01	10/1/19	65.2	---	65.2
T-C02	10/1/19	66.6	---	66.6
T-D01	10/5/22	66.6	55%	121.1

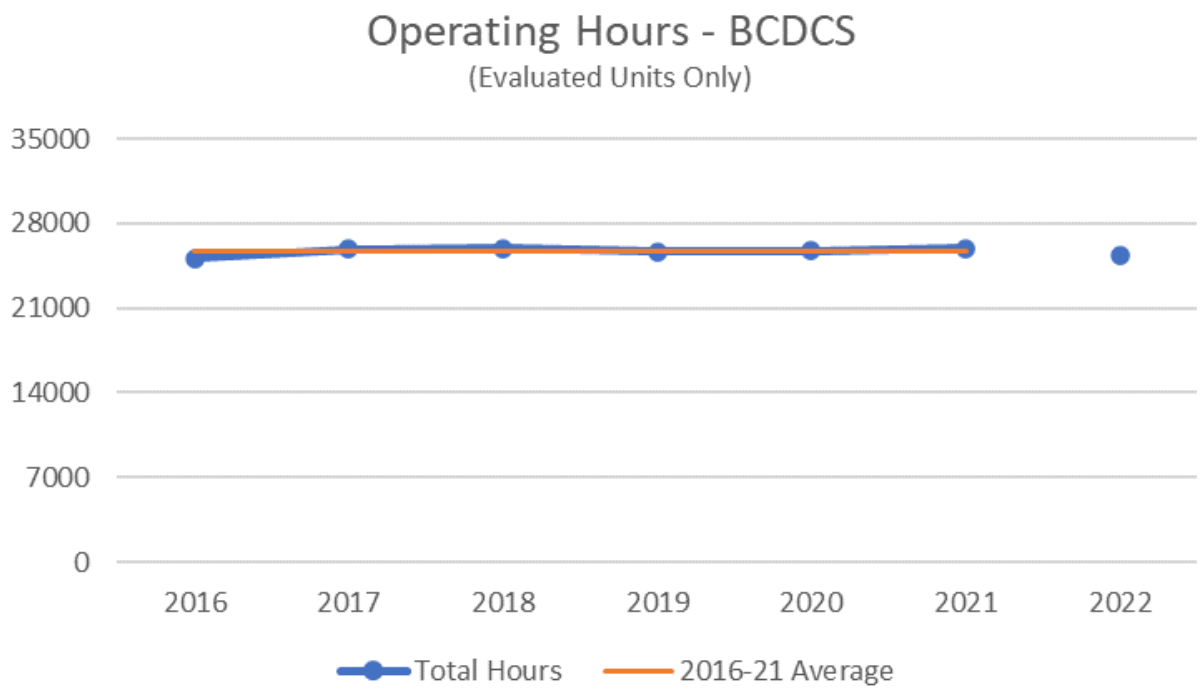
To determine representative annual operating hours for the emissions units at BCDCS, NMED analyzed 2016-2021 operating hours reported by Enterprise pursuant to 20.2.73 NMAC. NMED was in receipt of Enterprise's reported 2022 operating hours at the time of its analysis, but the data were still undergoing internal QA/QC checks and had not been certified yet, so NMED excluded them from its analysis. 2016-2021 operating hours for the emissions units at BCDCS are summarized and plotted below; reported 2022 operating hours are included for informational purposes only.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
T-C01	8591	8603	8635	8357	8444	8663	8458
T-C02	8505	8644	8692	8760	8634	8663	8442
T-D01	8003	8617	8651	8558	8652	8628	8442

[59] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.

[60] NMED lacked sufficient test data to adjust emission rates for Units T-C01 and T-C02. Therefore, unadjusted rates were used for these units.

[61] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.



As shown above, BCDCS' year-over-year operating hours have been very consistent in recent years, with no discernible impact from the pandemic in 2020. Furthermore, in a detailed discussion with NMED on 7/13/23, Enterprise indicated that it does not expect future utilization of the emissions units at BCDCS to change and that it intends to utilize its assets. Therefore, NMED determined that 2016-2021 average operating hours are representative for these units.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the emissions units at BCDCS are summarized below.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
T-C01	65.2	8549	278.9
T-C02	66.6	8650	288.0
T-D01	121.1	8518	515.7

C.4.8.4 Technical Feasibility of Available Controls

As indicated in Section C.3.4, the following determinations were made regarding the technical feasibility of identified control options for the CT at BCDCS:

- SNCR and NSCR are not technically feasible options.
- GCP is a technically feasible option and is currently utilized by Enterprise based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)

- DLN is a technically feasible option for Unit T-D01 (DLN technology is not available for GE 5221W turbines comprising Units T-C01 and T-C02) and is expected to achieve a vendor-quoted NO_X emission rate of 35 ppm.[62]
- WSI is a technically feasible option expected to achieve a NO_X emission rate of 42 ppm.[63]
- SCR is a technically feasible option expected to achieve an average NO_X control efficiency of 80 percent.
- Unit replacement is a technically feasible option expected to achieve a NO_X emission rate of 9 ppm, consistent with the emission standards for new natural gas-fired combustion turbines in 20.2.50 NMAC.[64]
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, Enterprise did not indicate that it intends to permanently retire any of the affected units, so this option is not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants).

C.4.8.5 Four-Factor Analysis

In order to determine what control measures are necessary at BCDCS to make reasonable progress, NMED conducted a FFA of potential control measures for NO_X for the emissions units identified in section C.4.8.2 above. States are required to consider four statutory factors – cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[65]

C.4.8.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X emissions reduced, of each technically feasible control option identified in section C.4.8.4 above. NMED utilized source-specific cost estimates provided by Enterprise in its calculations whenever possible. In cases where Enterprise failed to provide source-specific cost estimates or NMED found estimates provided by Enterprise to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[66]

NMED's cost effectiveness values for all technically feasible controls for the emissions units at BCDCS are summarized below. NMED believes these values were calculated using the most representative

[62] Per Enterprise's 8/30/23 submittal.
[63] The target emission rate for WSI is based on information contained in "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines" (US Department of Energy, 1999).
[64] 20.2.50 NMAC contains varying emission standards for new natural gas-fired stationary combustion turbines based on rated brake horsepower. See Section 113, Table 3. Equivalent replacements for the CT at BCDCS would be subject to the NO_X standard for new CT ≥15,900 bhp (9 ppm).
[65] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).
[66] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

information available and in a manner consistent with EPA-approved methodology. Detailed cost effectiveness calculations for the emissions units at BCDCS and supporting documentation for NMED's cost estimates are provided in Appendix D.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
T-C01	WSI	$987,001	84.8	$12,000
	SCR	$1,227,378	223.1	$6,000
	Replacement	$8,033,866	237.3	$34,000
	Electrification	$9,798,421	278.9	$35,000
T-C02	WSI	$987,001	114.5	$9,000
	SCR	$1,229,972	230.4	$5,000
	Replacement	$8,033,866	250.8	$32,000
	Electrification	$9,851,325	288.0	$34,000
T-D01	DLN	$862,295	282.3	$3,000
	WSI	$987,001	235.6	$4,000
	SCR	$1,745,604	412.6	$4,000
	Replacement	$11,711,815	455.7	$26,000
	Electrification	$14,315,018	515.7	$28,000

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the emissions units at BCDCS:

- Enterprise provided a company-specific cost of capital (10.5 percent) in its 8/30/23 submittal.
- Enterprise estimated the Total Capital Investment (TCI) for DLN using the capital cost factors for gas absorbers in EPA Control Cost Manual Section 5.2, Chapter 1, Table 1.3. Chapter 1 of Section 5.2 of the Control Cost Manual pertains to post-combustion controls for acid gases and is not applicable to pre-combustion controls for NO_X, such as DLN. Therefore, NMED disregarded Enterprise's estimate and utilized the underlying vendor quote provided by Enterprise in its 8/30/23 submittal.
- Enterprise failed to provide supporting documentation for its capital and operating cost estimates for WSI. Therefore, NMED developed its own estimates using cost data for similar-sized turbines provided by the U.S. Department of Energy.
- The Total Capital Costs (TCC), Direct Annual Costs (DAC), and Indirect Annual Costs (OAC) of SCR were calculated using EPA's SCR Tool. Enterprise asserted that limited physical space precludes the option of installing SCR and provided an aerial image with measurement overlays to support this assertion. However, the image provided suggests there is physical space for SCR if building modifications are made. To account for the additional capital costs needed to create space, NMED applied an SCR retrofit factor of 1.1 (above average difficulty) in its analysis.
- Enterprise, like most of the companies required to submit a FFA, did not provide information regarding the TCI associated with the replacement of their CT units with new, functionally equivalent natural gas-fired units. NMED reviewed several publicly available resources with

information that could be used to estimate the TCI of a replacement CT[67] along with information provided by other companies with similar units. NMED determined that the most applicable cost metric ($ per hp basis) was provided by El Paso Natural Gas Company in support of their FFA submittals. NMED understands that the use of this metric is likely accurate to within ±30 percent, but also recognizes that various preliminary vendor quotes are often caveated with a similar degree of accuracy.

- Enterprise estimated the TCI for electrification using the capital cost factors for gas absorbers in EPA Control Cost Manual Section 5.2, Chapter 1, Table 1.3. Chapter 1 of Section 5.2 of the Control Cost Manual pertains to post-combustion controls for acid gases and is not applicable to replacement with EMD. Therefore, NMED applied a Total Capital Cost (TCC) metric of $2,084/hp (2023$), which it developed using detailed cost information provided by other facilities, to calculate TCC. The TCI calculated by NMED assumes no costs associated with substation or utility line upgrades because of lack of information. NMED understands that this assumption likely underestimates costs given that Enterprise indicated utility infrastructure upgrades would be needed to support electrification at BCDCS.

C.4.8.5.2 Compliance Time

Enterprise indicated it would take 3-4 years to implement WSI or DLN on the CT at BCDCS. Based on information provided by other facilities and other resources, NMED believes these timeframes are reasonable.

Enterprise did not provide information regarding the time necessary to implement SCR or to replace their CT units with new, functionally equivalent natural gas-fired units. NMED believes the general compliance times for SCR and replacement provided in Section C.3.4 are reasonably accurate.

In its 8/30/23 submittal, Enterprise estimated that electrification would take 5-8 years based on the slow completion of electric utility infrastructure work in the region and anticipated development delays. NMED disagrees with this estimate based on information provided by other facilities and the implementation time of electrification projects at other facilities. NMED believes the general compliance time for electrification, provided in Section C.3.4, is more reasonable but recognizes several more years could be required considering the relative complexity.

C.4.8.5.3 Remaining Useful Life

Despite the age of the units at BCDCS, owners and operators of gas compression equipment in New Mexico have indicated that similar CT would last at least 20 more years with proper maintenance. Twenty years is thus the estimated remaining useful life for DLN. WSI is an exception as Enterprise indicated this control has a useful life of 15 years.

Consistent with generally accepted EPA methodology and NMED's experience, the useful life of SCR is estimated to be 20 years.

[67] This includes, but is not limited to, the U.S. EPA's Combined Heat and Power Catalog of Technologies (Reciprocating engines) and the U.S. Energy Information Agency's *Cost and Performance Characteristics of New Generating Technologies* in the 2023 Annual Energy Outlook.

Manufacturers of new CT will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new CT are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement CT is 30 years.

There is limited information about the useful life of EMD units, but research suggests the useful life is at least 25 years.

C.4.8.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for CT is provided in Section C.3.4.

C.4.8.5.5 Summary

NMED performed a FFA for all technically feasible control options for NO_X for the units listed in Section C.4.8.2 above. The four statutory factors are discussed in Sections C.4.8.5.1 through C.4.8.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
T-C01	WSI	$12,000	3-4	15	None
	SCR	$6,000	3-4	20	None
	Replacement	$34,000	3-4	30	None
	Electrification	$35,000	4-6	25	None
T-C02	WSI	$9,000	3-4	15	None
	SCR	$5,000	3-4	20	None
	Replacement	$32,000	3-4	30	None
	Electrification	$34,000	4-6	25	None
T-D01	DLN	$3,000	3-4	20	None
	WSI	$4,000	3-4	15	None
	SCR	$4,000	3-4	20	None
	Replacement	$26,000	3-4	30	None
	Electrification	$28,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

C.4.8.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze

Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[68]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For emissions units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For emissions units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective control is necessary to make reasonable progress. The sole exception to these general rules is the categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

NMED's FFA identified cost-effective controls for BCDCS Units T-C01, T-C02, and T-D01. Based on its analysis of the four statutory factors and the decision-making criteria described above, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
T-C01	SCR	223.1
T-C02	SCR	230.4
T-D01	SCR	412.6

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
T-C02	WSI	Less stringent than SCR
T-D01	DLN	Less stringent than SCR
T-D01	WSI	Less stringent than SCR

Based on the expected reductions from the controls NMED has determined are necessary to make reasonable progress, NMED estimates the total emissions reductions at BCDCS during the second planning period will be approximately 866.1 ton/yr of NO_X.

C.4.9 Enterprise Field Services - Chaco Gas Plant

Resources used in NMED's FFA for Chaco Gas Plant (CGP) include, but are not limited to, the following:

- The FFA completed by Trinity Consultants for Enterprise Field Services, LLC (Enterprise) and submitted to NMED on 11/14/19.
- Additional information provided by Enterprise on 2/24/20, 9/8/20, 10/1/20, 3/4/21, 3/12/21, 8/30/23, and 9/20/24.
- Detailed discussions between Enterprise and NMED on 8/28/20 and 7/13/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.

[68] See *supra* note 13.

- U.S. EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP region (March 23, 2020)
- FFAs developed for similar facilities in New Mexico and other states.

C.4.9.1 Facility Description

CGP is a natural gas processing facility located 14 miles southwest of Bloomfield in San Juan County, New Mexico at latitude 36° 29' 00", longitude -108° 07' 13". It is owned by Enterprise and operated by Enterprise Products Operating, LLC, and currently operates under Title V Operating Permit No. P116-R3, which expires on November 13, 2025. The shortest distance to the boundary of the nearest Class I Area, Mesa Verde National Park, is approximately 49.8 miles.

The function of the facility is to receive field natural gas, process the gas through removal of water, then extract/separate natural gas liquids (NGL) through a cryogenic process. Recovered NGL are then treated to remove carbon dioxide and hydrogen sulfide, and then delivered to a pipeline for transport to fractionation facilities downstream. The facility is authorized for continuous operation, and its total potential to emit is 2608.6 tons per year of NO_X and 91.8 tons per year of SO_2.[69]

C.4.9.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at CGP:[70]

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
12	2SLB RICE	Clark TLA-10	1966	3,400 hp
13	2SLB RICE	Clark TLA-10	1966	3,400 hp
14	2SLB RICE	Clark TLA-10	1966	3,400 hp
17	Turbine	General Electric Frame 5	1970	19,500 hp
18	Turbine	General Electric Frame 5	1971	19,500 hp
35	Turbine	Solar Mars T-15000	1996	15,000 hp
36	Turbine	Solar Mars T-15000	1996	15,000 hp
37	Turbine	Solar Mars T-15000	1996	15,000 hp

NMED also elected to evaluate the ATS at CGP for potential control measures for SO_2 due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). The ATS at CGP consists of an ATU (Unit AM-01), TO (Unit 46), and emergency flare (Unit 44). During normal operations, acid gas exiting the ATU

[69] AQB Title V Operating Permit No. P116-R3, Table 102.A.

[70] See Chapter 6, Selection of Sources for Control Measures Analysis, for a discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.

is routed to the TO for disposal. During TO SSM/M events, acid gas is rerouted to the emergency flare for disposal.

C.4.9.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. Enterprise did not request a future utilization adjustment for CGP. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the emissions units at CGP.

For the emissions units at CGP requiring a FFA of potential control measures for NO_X ("NO_X units"), NMED calculated baseline actual emissions by multiplying representative annual operating hours by the NO_X emission rates reported in Enterprise's most recent periodic emissions test report(s).[71,] Because the NO_X units at CGP operate at varying loads, NMED conservatively adjusted reported emission rates to 100 percent load to represent worst-case emissions.[72] Reported and adjusted emission rates for the NO_X units at CGP are summarized below.

Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr @ 100% load)
12	8/15/22	27.48	96%	28.63
13	6/22/22	15.33	97%	15.80
14	8/16/22	37.39	98%	38.15
17	8/9/22	17.02	97%	17.55
18	8/9/22	18.38	98%	18.76
35	8/2/22	25.43	97%	26.22
36	8/10/22	29.29	97%	30.20
37	8/10/22	28.49	96%	29.68

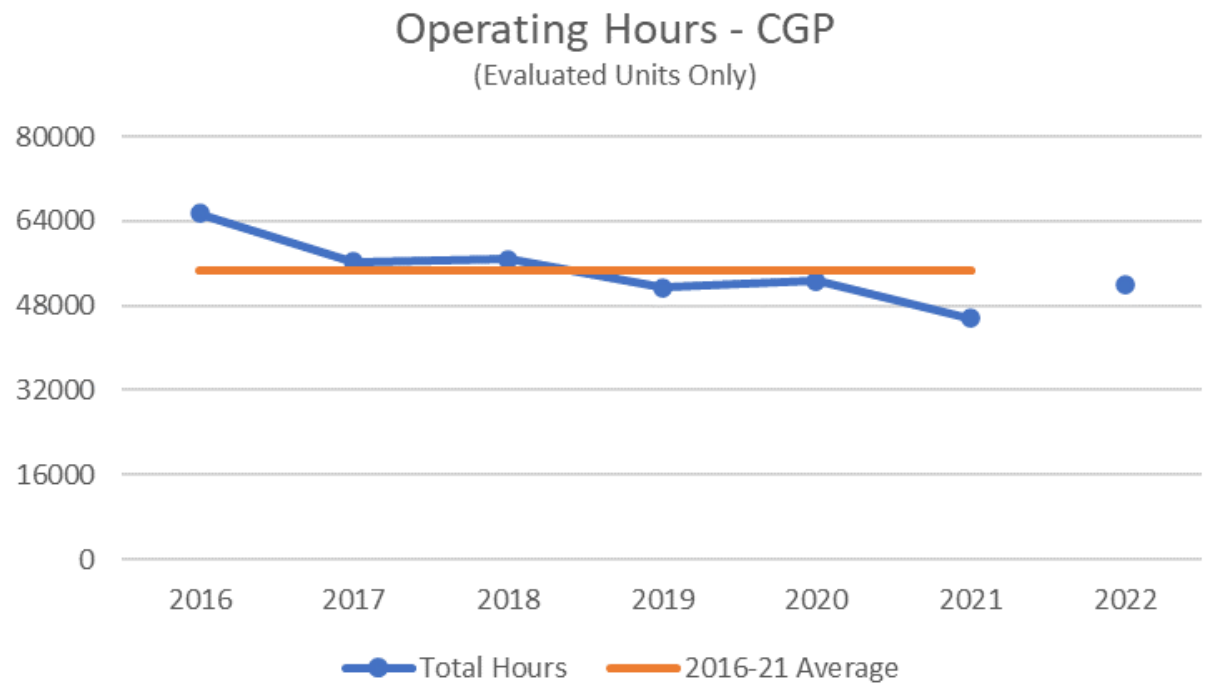
To determine representative annual operating hours for the NO_X units at CGP, NMED analyzed 2016-2021 operating hours reported by Enterprise pursuant to 20.2.73 NMAC. NMED was in receipt of Enterprise's reported 2022 operating hours at the time of its analysis, but the data were still undergoing internal QA/QC checks and had not been certified yet, so NMED excluded them from its analysis. 2016-2021 operating hours for the NO_X units at CGP are summarized and plotted below; reported 2022 operating hours are included for informational purposes only.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
12	7765	8052	7076	6047	6985	1260	6021
13	7815	8171	4871	4313	2793	3756	5850
14	7941	4699	8433	6555	7755	5881	5572

[71] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.

[72] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
17	8701	8471	8647	8533	8734	8430	8548
18	8680	8531	8518	8682	8715	8665	8393
35	8623	7519	6789	8179	7951	5817	4114
36	8418	4627	4769	3789	6534	8622	8396
37	7497	6240	7703	5391	3202	3187	5206



As shown above, year-over-year operating hours for the NO_X units at CGP have been fairly consistent in recent years, although somewhat higher variability was observed in 2016 and 2021. However, this increased variability was firmly centered around the 2016-2021 average so its effect on the average was negligible, and there was no discernible impact from the pandemic in 2020. Furthermore, in a detailed discussion with NMED on 7/13/23, Enterprise indicated that it does not expect future utilization of the NO_X units at CGP to change and that it intends to utilize its assets. Therefore, NMED determined that 2016-2021 average operating hours are representative for these units.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the NO_X units at CGP are summarized below.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
12	28.63	6198	88.7
13	15.8	5287	41.8
14	38.15	6877	131.2
17	17.55	8586	75.3

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
18	18.76	8632	80.9
35	26.22	7480	98.0
36	30.20	6127	92.5
37	29.68	5537	82.2

C.4.9.4 Technical Feasibility of Available Controls

As indicated in Section C.3.1, the following determinations were made regarding the technical feasibility of identified control options for the 2SLB RICE at CGP:

- SCR, SNCR, and NSCR are not technically feasible options.
- GCP is a technically feasible option and is currently utilized by Enterprise based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- LEC is a technically feasible option expected to achieve a vendor-quoted, not-to-exceed NO_X emission rate of 0.5 g/hp-hr.
- Unit replacement is a technically feasible option expected to achieve a NO_X emission rate of 0.3 g/hp-hr, consistent with the emissions standards for new natural gas-fired spark ignition lean burn engines in 20.2.50 NMAC.[73]
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, Enterprise has not indicated that it intends to permanently retire any of the affected units, so this option is not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and other pollutants).

As indicated in Section C.3.4, the following determinations were made regarding the technical feasibility of identified control options for the CT at CGP:

- SNCR and NSCR are not technically feasible options.
- GCP is a technically feasible option and is currently utilized by Enterprise based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- DLN is a technically feasible option for Units 35, 36, and 37 (DLN technology is not available for the GE Frame 5 turbines comprising Units 17 and 18) expected to achieve a vendor-quoted NO_X emission rate of 9 ppm.[74]

[73] 20.2.50 NMAC contains varying emission standards for new natural gas-fired spark ignition engines based on engine type and rated brake horsepower. See Section 113, Table 2. Equivalent replacements for the 2SLB RICE at CGP would be subject to the NO_X standard for new lean burn engines ≥1,875 bhp (0.3 g/bhp-hr).

[74] Per Enterprise's 9/20/24 submittal, which included a letter from Solar Turbines stating that Solar offers SoLoNOx (DLN) upgrades to 9 ppm NOx for the Mars 100 turbines at CGP and 15 ppm for the Centaur 40 turbines at South Carlsbad Compressor Station.

- WSI is a technically feasible option for Units 17 and 18 (WSI is not available for the Solar Mars turbines comprising Units 35, 36, and 37) expected to achieve a NO_X emission rate of 42 ppm.[75]
- SCR is a technically feasible option expected to achieve an average NO_X control efficiency of 80 percent.
- Unit replacement is a technically feasible option expected to achieve a NO_X emission rate of 9 ppm or 15 ppm depending on the unit, consistent with the emissions standards for new natural gas-fired combustion turbines in 20.2.50 NMAC. [76]
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, Enterprise did not indicate that it intends to permanently retire any of the affected units, so this option is not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and other pollutants).

As indicated in Section C.3.6, the following determinations were made regarding the technical feasibility of identified control options for the ATS at CGP:

- A flare is a technically feasible option. However, if used as the primary control device, a flare is inferior to all other forms of disposal because most of the H_2S in the acid gas stream (typically 98% or more) is converted to SO_2 and emitted into the atmosphere. Therefore, NMED did not evaluate this option.
- A SRU is a technically feasible option. However, no facility with an ATS evaluated by NMED currently uses a SRU. Many, and possibly all gas processing plants in New Mexico that previously used a SRU have decommissioned them in recent years due to operational concerns and/or compliance issues, some of which resulted in enforcement actions against the facility due to significant excess SO_2 emissions. NMED supports and encourages the transition away from SRUs towards more effective forms of acid gas disposal, such as AGI wells. In addition, NMED is confident that the cost effectiveness of a SRU would exceed its $10,000/ton cost effectiveness threshold, for the same reason it believes an AGI well would exceed the threshold (see explanation below). Therefore, NMED did not evaluate this option.
- A TO is a technically feasible option and is currently used as the primary control device for the ATS at CGP. Therefore, NMED did not evaluate this option.
- The technical feasibility of an AGI well is extremely dependent on the geologic characteristics of the potential well site. Therefore, absent a detailed geologic study, NMED is unable to determine whether an AGI well is technically feasible at CGP. However, even assuming an AGI well is technically feasible, NMED believes it has sufficient information to conclude that it would not be cost effective without performing a full FFA. Gas produced from the San Juan Basin in northwest New Mexico is primarily "sweet" gas containing relatively little H_2S. As a result, the primary purpose of the ATS at CGP is to remove CO_2 from recovered NGL, although small quantities of H_2S are also removed. Given the small quantities of H_2S removed by the ATS, SO_2 emissions from

[75] The target emission rate for WSI is based on information contained "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines" (US Department of Energy, 1999).

[76] 20.2.50 NMAC contains varying emission standards for new natural gas-fired stationary combustion turbines based on rated brake horsepower. See Section 113, Table 3. Equivalent replacements for Units 17 and 18 would be subject to the NO_X standard for new CT ≥15,900 bhp (9 ppm), while equivalent replacements for Units 35, 36, and 37 would be subject to the NO_X standard for new CT ≥4,000 and <15,900 bhp (15 ppm).

the TO average just 3.6 tons per year.[77] Hence, the potential emissions reductions from installing an AGI well are extremely limited. Considering that the capital costs for an AGI well, two compressors (primary and backup), and related piping can easily exceed $10 million, NMED is confident, given the potential for just a few tons of emissions reductions, that the cost effectiveness of an AGI well would greatly exceed its $10,000/ton cost effectiveness threshold. Therefore, NMED did not evaluate this option.

- While improved flare design might reduce emissions somewhat during TO SSM/M events, the potential marginal improvement in combustion efficiency – perhaps 1 to 2 percentage points – from the most optimized flare is not anticipated to be a cost-effective option for reducing SO_2 emissions from acid gas flaring during TO SSM/M events. Therefore, NMED did not evaluate this option.

C.4.9.5 Four-Factor Analysis

In order to determine what control measures are necessary at CGP to make reasonable progress, NMED conducted a FFA of potential control measures for the NO_X units identified in section C.4.9.2 above. NMED did not conduct a FFA of potential control measures for SO_2 for CGP's ATS because alternatives to the existing TO are either inferior, not cost effective, or both. States are required to consider four statutory factors – cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[78]

C.4.9.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X emissions reduced, of each technically feasible control option identified in section C.4.9.4 above. NMED utilized source-specific cost estimates provided by Enterprise in its calculations whenever possible. In cases where Enterprise failed to provide source-specific cost estimates or NMED found estimates provided by Enterprise to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[79]

NMED's cost effectiveness values for all technically feasible controls for the NO_X units at CGP are summarized below. NMED believes these values were calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed cost effectiveness calculations for the NO_X units at CGP and supporting documentation for NMED's cost estimates are provided in Appendix D.

[77] Based on 2016-2022 emission inventory data.

[78] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).

[79] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
12	LEC	$946,197	77.1	$12,000
	Replacement	$1,625,013	81.7	$20,000
	Electrification	$1,307,009	88.7	$15,000
13	LEC	$946,197	31.9	$30,000
	Replacement	$1,625,013	35.8	$45,000
	Electrification	$1,234,069	41.8	$30,000
14	LEC	$946,197	118.3	$8,000
	Replacement	$1,625,013	123.5	$13,000
	Electrification	$1,361,441	131.2	$10,000
17	WSI	$987,001	-21.5 (1)	-$46,000 (1)
	SCR	$1,152,663	60.3	$19,000
	Replacement	$7,127,287	54.6	$131,000
	Electrification	$8,592,884	75.3	$114,000
18	WSI	$987,001	-18.1 (1)	-$55,000 (1)
	SCR	$1,166,729	64.8	$18,000
	Replacement	$7,127,287	59.7	$119,000
	Electrification	$8,613,931	80.9	$106,000
35	DLN	$1,033,311	90.4	$11,000
	SCR	$868,469	78.4	$11,000
	Replacement	$5,515,722	85.3	$65,000
	Electrification	$6,219,119	98.0	$63,000
36	DLN	$1,033,311	86.1	$12,000
	SCR	$858,488	74.0	$12,000
	Replacement	$5,515,722	81.8	$67,000
	Electrification	$5,741,137	92.5	$62,000
37	DLN	$1,033,311	76.1	$13,000
	SCR	$852,857	65.7	$13,000
	Replacement	$5,515,722	72.1	$77,000
	Electrification	$5,532,789	82.2	$67,000

(1) Negative estimated reductions and cost effectiveness are an artifact of NMED's methods for calculating these values and do not accurately represent the cost effectiveness of the control or its expected emissions impact. Negative values are an indication that the emission rate associated with the control is greater than the current emission rate of the unit in question, which means the control would not be expected to reduce emissions. Controls that would not reduce emissions are not cost effective on their face and are excluded from further consideration.

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the NO_X units at CGP:

- Enterprise provided a company-specific cost of capital (10.5 percent) in its 8/30/23 submittal.
- In its 11/14/19 FFA, Enterprise stated that the 2SLB RICE at CGP are currently equipped with LEC. Based on Enterprise's most recent periodic emissions test reports, controlled NO_X emissions from these units range from approximately 2.1 to 5.1 g/hp-hr. However, DCP provided NMED with a vendor cost estimate to retrofit similar 1970s vintage Clark TLA series 2SLB RICE with LEC capable of achieving 0.5 g/hp-hr. Therefore, NMED believes LEC upgrades are feasible for CGP's

RICE. To estimate the costs, NMED used a Total Capital Investment (TCI) metric of $1,525/hp (2021$) developed from the vendor cost estimate provided by DCP.

- The TCI and Incremental Annual Costs for DLN retrofit of Units 35, 36 and 37 were provided by a vendor, Solar Turbines.
- Enterprise failed to provide supporting documentation for its capital and operating cost estimates for WSI. Therefore, NMED developed its own estimates using cost data for similar-sized turbines provided by the U.S. Department of Energy.
- The Total Capital Costs (TCC), Direct Annual Costs (DAC), and Indirect Annual Costs (OAC) of SCR were calculated using EPA's SCR Tool. Enterprise asserted that limited physical space precludes the option of installing SCR and provided an aerial image with measurement overlays to support this assertion. However, the image provided suggests there is physical space for SCR if building modifications are made. To account for the additional capital costs needed to create space, NMED applied an SCR retrofit factor of 1.1 (above average difficulty) in its analysis.
- Enterprise, like most of the companies required to submit a FFA, did not provide information regarding the TCI associated with the replacement of their RICE and CT units with new, functionally equivalent natural gas-fired units. NMED reviewed several publicly available resources with information that could be used to estimate the TCI of a replacement RICE or CT[80] along with information provided by other companies with similar units. NMED determined that the most applicable cost metrics ($ per hp basis) were provided by El Paso Natural Gas Company in support of their FFA submittals. NMED understands that the use of these metrics is likely accurate to within ±30 percent, but also recognizes that various preliminary vendor quotes are often caveated with a similar degree of accuracy.
- Enterprise estimated the TCI for electrification using the capital cost factors for gas absorbers in EPA Control Cost Manual Section 5.2, Chapter 1, Table 1.3. Chapter 1 of Section 5.2 of the Control Cost Manual pertains to post-combustion controls for acid gases and is not applicable to replacement with EMD. Therefore, NMED applied a Total Capital Cost (TCC) metric of $2,084/hp (2023$), which it developed using detailed cost information provided by other facilities, to calculate TCC. The TCI calculated by NMED assumes no costs associated with substation or utility line upgrades because of lack of information. NMED understands that this assumption likely underestimates costs given that Enterprise indicated utility infrastructure upgrades would be needed to support electrification at CGP.

C.4.9.5.2 Compliance Time

Enterprise did not identify any technically feasible control options for the 2SLB RICE at CGP (other than those already implemented) in its FFA submittal, so it did not provide estimated compliance times for any of the control options NMED has determined are technically feasible. NMED's general assessment of compliance times provided in Section C.3.1 are believed to be reasonably accurate.

Enterprise indicated it would take approximately 3-4 years to implement DLN on CT Units 17 and 18 and approximately 3-4 years to implement WSI on CT Units 35, 36, and 37. Based on information provided by other facilities and other resources, NMED believes these timeframes are reasonable.

[80] This includes, but is not limited to, the U.S. EPA's Combined Heat and Power Catalog of Technologies (Reciprocating engines) and the U.S. Energy Information Agency's *Cost and Performance Characteristics of New Generating Technologies* in the 2023 Annual Energy Outlook.

Enterprise did not provide information regarding the time necessary to implement SCR on their CT units or to replace their RICE and CT units with new, functionally equivalent natural gas-fired units. NMED believes the general compliance times for these control options provided in Sections C.3.1 and C.3.4 are reasonably accurate.

In 8/30/23 correspondence, Enterprise estimated that electrification would take 5-8 years based on the slow completion of electric utility infrastructure work in the region and expected development delays. NMED disagrees with this estimate based on information provided by other facilities and the implementation time of electrification projects at other facilities. NMED believes the general compliance time for electrification, provided in Sections C.3.1 and C.3.4, is more reasonable but recognizes several more years could be required considering the relative complexity.

C.4.9.5.3 Remaining Useful Life

Despite the advanced age of the units at CGP (~30 to 60 years), owners and operators of gas compression equipment in New Mexico have indicated that similar RICE and CT would last at least 20 more years with proper maintenance. Twenty years is thus the estimated remaining useful life for LEC and DLN. WSI is an exception as Enterprise indicated this control has a useful life of 15 years.

Consistent with generally accepted EPA methodology and NMED's experience, the useful life of SCR is estimated to be 20 years.

Manufacturers of new CT and RICE will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new CT and RICE are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement RICE and replacement CT is 30 years.

There is limited information about the useful life of EMD units, but research suggests the useful life is at least 25 years.

C.4.9.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for 2SLB RICE and CT is provided in Sections C.3.1 and C.3.4, respectively.

C.4.9.5.5 Summary

NMED performed a FFA for all technically feasible control options for the NO_X units listed in Section C.4.9.2 above. The four statutory factors are discussed in Sections C.4.9.5.1 through C.4.9.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts (1)
12	LEC	$12,000	2-3	20	None
	Replacement	$20,000	3-4	30	None
	Electrification	$15,000	4-6	25	None

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts (1)
13	LEC	$30,000	2-3	20	None
	Replacement	$45,000	3-4	30	None
	Electrification	$30,000	4-6	25	None
14	LEC	$8,000	2-3	20	None
	Replacement	$13,000	3-4	30	None
	Electrification	$10,000	4-6	25	None
17	WSI	-$46,000	3-4	15	None
	SCR	$19,000	3-4	20	None
	Replacement	$131,000	3-4	30	None
	Electrification	$114,000	4-6	25	None
18	WSI	-$55,000	3-4	15	None
	SCR	$18,000	3-4	20	None
	Replacement	$119,000	3-4	30	None
	Electrification	$106,000	4-6	25	None
35	DLN	$11,000	3-4	20	None
	SCR	$11,000	3-4	20	None
	Replacement	$65,000	3-4	30	None
	Electrification	$63,000	4-6	25	None
36	DLN	$12,000	3-4	20	None
	SCR	$12,000	3-4	20	None
	Replacement	$67,000	3-4	30	None
	Electrification	$62,000	4-6	25	None
37	DLN	$13,000	3-4	20	None
	SCR	$13,000	3-4	20	None
	Replacement	$77,000	3-4	30	None
	Electrification	$67,000	4-6	25	None

(1) Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

C.4.9.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze

Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[81]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For NO_X units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For NO_X units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective control is necessary to make reasonable progress. The sole exception to these general rules is the categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

NMED's FFA identified cost-effective controls for CGP Unit 14. Based on its analysis of the four statutory factors and the decision-making criteria described above, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
14	LEC	118.3

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
14	Electrification	Categorically excluded

NMED's FFA did not identify any cost-effective controls for CGP Units 12, 13, 17, 18, 35, 36, or 37. Therefore, NMED determined that reasonable progress does not require new controls on any of these units.

As noted above, NMED did not conduct a FFA of potential control measures for CGP's ATS. Because the alternatives to the existing TO are either inferior, presumptively not cost effective, or both, NMED determined that reasonable progress does not require new controls for the ATS.

Based on the expected reductions from the controls NMED has determined are necessary to make reasonable progress, NMED estimates the total emissions reductions at CGP during the second planning period will be approximately 118.3 ton/yr of NO_X.

C.4.10 Enterprise Field Services – South Carlsbad Compressor Station

Resources used in NMED's FFA for South Carlsbad Compressor Station (SCCS) include, but are not limited to, the following:

- The FFA completed by Trinity Consultants for Enterprise Field Services, LLC (Enterprise) and submitted to NMED on 10/30/19.

[81] See *supra* note 13.

- Additional information provided by Enterprise on 2/13/20, 2/26/20, 3/17/20, 9/8/20, 10/1/20, 3/4/21, 3/12/21, 8/30/23, and 9/20/24.
- Detailed discussions between Enterprise and NMED on 8/28/20 and 7/13/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP region (March 23, 2020)
- FFAs developed for similar facilities in New Mexico and other states.

C.4.10.1 Facility Description

SCCS is a natural gas compressor station located 2.8 miles northwest of Loving in Eddy County, New Mexico at latitude 32° 18' 56", longitude -104° 08' 12". It is owned by Enterprise and operated by Enterprise Products Operating, LLC, and currently operates under Title V Operating Permit No. P130-R4, which expires on June 9, 2028. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 16.2 miles.

The function of the facility is to compress gas to direct to a pipeline for transport. The facility is authorized for continuous operation, and its total potential to emit is 211.3 tons per year of NO_X and 17.0 tons per year of SO_2.[82]

C.4.10.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at SCCS. No units met NMED's criteria for requiring an evaluation of potential control measures for SO_2.[83]

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
1	Turbine	Solar Centaur T-4702	1973	4,328 hp
2	Turbine	Solar Centaur T-4702	1979	4,328 hp

C.4.10.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. Enterprise did not request a future utilization adjustment for SCCS. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the emissions units at SCCS.

[82] AQB Title V Operating Permit No. P130-R4, Table 102.A.

[83] See Chapter 6, Selection of Sources for Control Measures Analysis, for a detailed discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.

NMED calculated baseline actual emissions for the emissions units at SCCS by multiplying representative annual operating hours by the NO_X emission rates reported in Enterprise's most recent periodic emissions test report(s).[84,] Because the emissions units at SCCS operate at varying loads, NMED conservatively adjusted reported emission rates to 100 percent load to represent worst-case emissions.[85] Reported and adjusted emission rates for the emissions units at SCCS are summarized below.

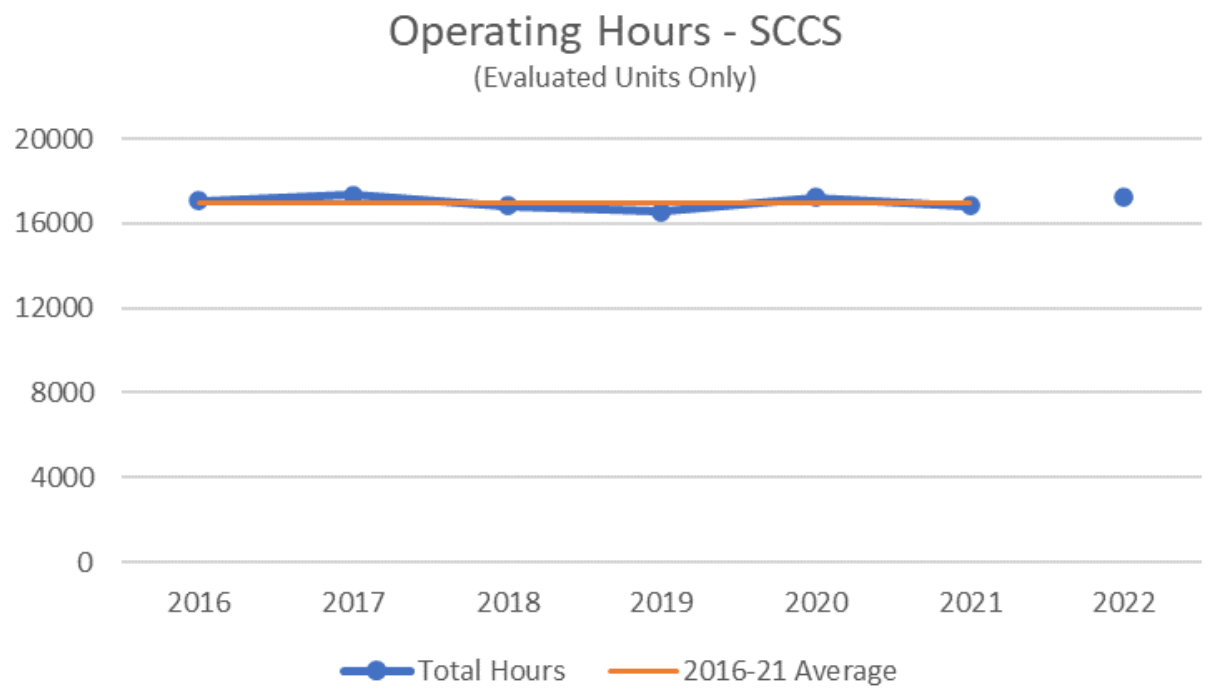
Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr @ 100% load)
1	5/17/23	17.6	97%	18.1
2	5/17/23	18.2	100%	18.2

To determine representative annual operating hours for the emissions units at SCCS, NMED analyzed 2016-2021 operating hours reported by Enterprise pursuant to 20.2.73 NMAC. NMED was in receipt of Enterprise's reported 2022 operating hours at the time of its analysis, but the data were still undergoing internal QA/QC checks and had not been certified yet, so NMED excluded them from its analysis. 2016-2021 operating hours for the emissions units at SCCS are summarized and plotted below; reported 2022 operating hours are included for informational purposes only.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
1	8543	8747	8418	8407	8610	8420	8603
2	8544	8611	8415	8171	8639	8424	8634

[84] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.

[85] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.



As shown above, SCCS' year-over-year operating hours have been very consistent in recent years, with no discernible impact from the pandemic in 2020. Furthermore, in a detailed discussion with NMED on 7/13/23, Enterprise indicated that it does not expect future utilization of the emissions units at SCCS to change and that it intends to utilize its assets. Therefore, NMED determined that 2016-2021 average operating hours are representative for these units.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the emissions units at SCCS are summarized below.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
1	18.1	8524	77.2
2	18.2	8467	76.9

C.4.10.4 Technical Feasibility of Available Controls

As indicated in Section C.3.4, the following determinations were made regarding the technical feasibility of identified control options for the CT at SCCS:

- SNCR and NSCR are not technically feasible options.
- GCP is a technically feasible option and is currently utilized by Enterprise based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- DLN is a technically feasible option expected to achieve a vendor-quoted NO_X emission rate of 15 ppm.

- WSI is not a technically feasible option. The manufacturer, Solar Turbines, does not support the technology.
- SCR is a technically feasible option expected to achieve an average NO_X control efficiency of 80 percent.
- Unit replacement is a technically feasible option expected to achieve a NO_X emission rate of 15 ppm, consistent with the emissions standards for new natural gas-fired combustion turbines in 20.2.50 NMAC.[86]
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, Enterprise did not indicate that it intends to permanently retire any of the affected units, so this option is not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants).

C.4.10.5 Four-Factor Analysis

In order to determine what control measures are necessary at SCCS to make reasonable progress, NMED conducted a FFA of potential control measures for NO_X for the emissions units identified in section C.4.10.2 above. States are required to consider four statutory factors – cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[87]

C.4.10.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X emissions reduced, of each technically feasible control option identified in section C.4.10.4 above. NMED utilized source-specific cost estimates provided by Enterprise in its calculations whenever possible. In cases where Enterprise failed to provide source-specific cost estimates or NMED found estimates provided by Enterprise to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[88]

NMED's cost effectiveness values for all technically feasible controls for the emissions units at SCCS are summarized below. NMED believes these values were calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed cost effectiveness calculations for the emissions units at SCCS and supporting documentation for NMED's cost estimates are provided in Appendix D.

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[86] 20.2.50 NMAC contains varying emission standards for new natural gas-fired stationary combustion turbines based on rated brake horsepower. See Section 113, Table 3. Equivalent replacements for the CT at SCCS would be subject to the NO_X standard for new CT ≥4,000 and <15,900 bhp (15 ppm).

[87] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).

[88] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
1	DLN	$263,725	68.0	$4,000
	SCR	$400,268	61.8	$6,000
	Replacement	$1,594,731	68.0	$23,000
	Electrification	$1,900,878	77.2	$25,000
2	DLN	$263,725	67.7	$4,000
	SCR	$400,118	61.5	$7,000
	Replacement	$1,594,731	67.7	$24,000
	Electrification	$1,895,085	76.9	$25,000

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the emissions units at SCCS:

- Enterprise provided a company-specific cost of capital (10.5 percent) in its 8/30/23 submittal.
- Enterprise estimated the Total Capital Investment (TCI) for DLN using the capital cost factors for gas absorbers in EPA Control Cost Manual Section 5.2, Chapter 1, Table 1.3. Chapter 1 of Section 5.2 of the Control Cost Manual pertains to post-combustion controls for acid gases and is not applicable to pre-combustion controls for NO_X, such as DLN. Therefore, NMED disregarded Enterprise's estimate and utilized the underlying vendor quote provided by Enterprise in its 8/30/23 submittal. Because this quote specifically excluded installation costs, NMED added installation costs equal to 15 percent of Total Capital Costs (TCC) to its TCI estimate.
- The Total Capital Costs (TCC), Direct Annual Costs (DAC), and Indirect Annual Costs (OAC) of SCR were calculated using EPA's SCR Tool. Enterprise asserted that limited physical space precludes the option of installing SCR and provided an aerial image with measurement overlays to support this assertion. However, the image provided suggests there is physical space for SCR if building modifications are made. To account for the additional capital costs needed to create space, NMED applied an SCR retrofit factor of 1.1 (above average difficulty) in its analysis.
- Enterprise, like most of the companies required to submit a FFA, did not provide information regarding the TCI associated with the replacement of their CT units with new, functionally equivalent natural gas-fired units. NMED reviewed several publicly available resources with information that could be used to estimate the TCI of a replacement CT[89] along with information provided by other companies with similar units. NMED determined that the most applicable cost metric ($ per hp basis) was provided by El Paso Natural Gas Company in support of their FFA submittals. NMED understands that the use of this metric is likely accurate to within ±30 percent, but also recognizes that various preliminary vendor quotes are often caveated with a similar degree of accuracy.
- Enterprise estimated the TCI for electrification using the capital cost factors for gas absorbers in EPA Control Cost Manual Section 5.2, Chapter 1, Table 1.3. Chapter 1 of Section 5.2 of the Control Cost Manual pertains to post-combustion controls for acid gases and is not applicable to replacement with EMD. Therefore, NMED applied a TCC metric of $2,084/hp (2023$), which it developed using detailed cost information provided by other facilities. The Total Capital

[89] This includes, but is not limited to, the U.S. EPA's Combined Heat and Power Catalog of Technologies (Reciprocating engines) and the U.S. Energy Information Agency's *Cost and Performance Characteristics of New Generating Technologies* in the 2023 Annual Energy Outlook.

Investment calculated by NMED assumes no costs associated with substation or utility line upgrades because of lack of information. NMED understands that this assumption likely underestimates costs given that Enterprise indicated utility infrastructure upgrades would be needed to support electrification at SCCS.

C.4.10.5.2 Compliance Time

Enterprise indicated it would take 3-4 years to implement DLN on the CT at SCCS. Based on information provided by other facilities and other resources, NMED believes this timeframe is reasonable.

Enterprise did not provide information regarding the time necessary to implement SCR or to replace their CT units with new, functionally equivalent natural gas-fired units. NMED believes the general compliance times for SCR and replacement provided in Section C.3.4 are reasonably accurate.

In 8/30/23 correspondence, Enterprise estimated that electrification would take 5-8 years based on the slow completion of electric utility infrastructure work in the region and expected development delays. NMED disagrees with this estimate based on information provided by other facilities and the implementation time of electrification projects at other facilities. NMED believes the general compliance time for electrification, provided in Section C.3.4, is more reasonable but recognizes several more years could be required considering the relative complexity.

C.4.10.5.3 Remaining Useful Life

Enterprise indicated that the expected useful life of DLN is 20 years. This is consistent with information provided by similar facilities and FFAs completed in other states.

Consistent with generally accepted EPA methodology and NMED's experience, the useful life of SCR is estimated to be 20 years.

Manufacturers of new CT will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new CT are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement CT is 30 years.

There is limited information about the useful life of EMD units, but research suggests the useful life is at least 25 years.

C.4.10.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for CT is provided in Section C.3.4.

C.4.10.5.5 Summary

NMED performed a FFA for all technically feasible control options for NO_X for the units listed in Section C.4.10.2 above. The four statutory factors are discussed in Sections C.4.10.5.1 through C.4.10.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
1	DLN	$4,000	3-4	20	None
	SCR	$6,000	3-4	20	None
	Replacement	$23,000	3-4	30	None
	Electrification	$25,000	4-6	25	None
2	DLN	$4,000	3-4	20	None
	SCR	$7,000	3-4	20	None
	Replacement	$24,000	3-4	30	None
	Electrification	$25,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration

C.4.10.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[90]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For emissions units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For emissions units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective control is necessary to make reasonable progress. The sole exception to these general rules is the categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

NMED's FFA identified cost-effective controls for SCCS Units 1 and 2. Based on its analysis of the four statutory factors and the decision-making criteria described above, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
1	DLN	68.0
2	DLN	67.7

[90] See *supra* note 13.

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
1	SCR	Less stringent than DLN
2	SCR	Less stringent than DLN

Based on the expected reductions from the controls NMED has determined are necessary to make reasonable progress, NMED estimates the total emissions reductions at SCCS during the second planning period will be approximately 135.7 ton/yr of NO_X.

C.4.11 ET Gathering & Processing – Jal #3 Gas Plant

Jal #3 Gas Plant (JGP) is a natural gas processing facility located 4 miles north-northeast of Jal in Lea County, New Mexico at latitude 32° 10' 25", longitude -103° 10' 27". It is owned and operated by ET Gathering & Processing LLC – formerly ETC Texas Pipeline LTD (ETC) – and currently operates under Title V Operating Permit No. P090-R3M1, which expired on March 27, 2024.[91] The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 70 miles.

JGP was one of 23 facilities selected for an analysis of potential control measures when NMED performed the source screening described in Section C.2 in 2019. NMED originally selected two 2SLB RICE (Units 4A and 5A) at JGP for an analysis of potential control measures for NO_X in the second planning period. NMED also elected to evaluate the ATS at JGP for potential control measures for SO_2 due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). At the time, the ATS consisted of gas treating and cryo processing facilities (Units Existing Treater and New Treater), a SRU (Unit SRU) with TO (Unit 9S), an AGI well with two electric compressors, and a treatment flare (Unit 9F). However, due to recent changes at JGP, NMED did not need to perform an analysis for any of these units.

ETC entered into a Settlement Agreement and Stipulated Final Compliance Order (SASFCO) with NMED on August 30, 2021, requiring ETC to shut down JGP's SRU within 60 days. ETC subsequently shut down the SRU on October 8, 2021, and submitted an administrative permit revision shortly thereafter removing it and the associated thermal oxidizer from JGP's NSR permit. ETC then decided to shut down JGP's existing gas treating and cryo processing facilities and install a new ATU (Unit Amine-2). As part of the project, ETC removed 10 compressor engines, including Units 4A and 5A, and installed a tertiary electric compressor for the AGI well to provide backup, redundant compression for the AGI well at all times (before ETC added the third compressor, the two existing compressors could both get overloaded at the same time causing acid gas to be rerouted to treatment flare 9F). These changes are reflected in JGP's current NSR permit (No. 1092-M10R3), and ETC's pending renewal application for Title V Operating Permit No. P090-R3M1 requests that they be incorporated into the facility's Title V permit as well.

EPA guidance provides that a state may forgo a full FFA if a source is already "effectively controlled" and the state can demonstrate why a FFA would not result in new controls and would therefore be a futile

[91] ETC submitted a timely application to renew Title V Operating Permit No. P090-R3M1 in March 2023. At the time of preparation of this technical support document, NMED had not taken final action on the application. Pursuant to 20.2.70.201 NMAC, a Title V source may continue to operate after its operating permit expires if it has submitted a timely renewal application and meets other requirements.

exercise.[92] NMED considers it self-evident that a FFA of potential control measures for retired units at a facility that has been shut down would be futile. There is no more effective control than retirement, which reduces emissions by 100 percent. Therefore, NMED has determined that Units 4A and 5A are effectively controlled by virtue of their retirement due to the shutdown of JGP's former gas treating and cryo processing facilities, and that a FFA could only result in the conclusion that no further controls are necessary to make reasonable progress.

Regarding the ATS, with the removal of the SRU and TO, all acid gas is now routed to the AGI well for disposal, resulting in no emissions to the atmosphere during normal operations. Flaring emissions are only produced during AGI SSM/M events, which are minimized via the new tertiary, redundant AGI well compressor. As discussed in Section C.3.6, the use of an AGI well with redundant compression is an optimal approach to reducing emissions from an ATS. Because JGP now utilizes this approach, NMED determined that reasonable progress does not require new controls for the ATS.

Based on when ETC shut down JGP's old gas treating and cryo processing facilities, shut down the SRU and TO, and added redundant compression to the AGI well, the emissions reductions resulting from the retirement of the affected units were realized during the second planning period. Therefore, NMED estimated the NO_X emissions reductions resulting from the retirement of Units 4A and 5A and the SO_2 emissions reductions resulting from the shutdown of the SRU and TO by averaging 2016-2020 emissions reported by DCP pursuant to 20.2.73 NMAC.[93] These emissions are summarized below.

Pollutant	2016 Emissions (tons)	2017 Emissions (tons)	2018 Emissions (tons)	2019 Emissions (tons)	2020 Emissions (tons)	2021 Emissions (tons)	Average Emissions (ton/yr)
NO_X	33.1	31.8	6.7	18.9	49.4	10.7	25.1
SO_2	143.6	111.3	423.8	208.6	17.9	21.2	154.4

C.4.12 Transwestern Pipeline Company – Mountainair Compressor Station No. 7

Resources used in NMED's FFA for Mountainair Compressor Station No. 7 (MCS) include, but are not limited to, the following:

- The FFA completed by GHD Services, Inc. for Transwestern Pipeline Company, LLC (TWP) and submitted to NMED on 10/30/19.
- Additional information provided by TWP on 01/23/20, 9/10/20, 3/25/21, and 8/11/23.
- Detailed discussions between TWP and NMED on 7/11/23 and 7/21/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).

[92] EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021) at 5.

[93] NMED did not have sufficient information to estimate the SO_2 reductions resulting from the addition of redundant compression to JGP's AGI well.

- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP region (March 23, 2020)
- FFAs developed for similar facilities in New Mexico and other states.

C.4.12.1 Facility Description

MCS is a natural gas compressor station located 12 miles south-southwest of Mountainair in Torrance County, New Mexico at latitude 34° 20' 29", longitude -106° 17' 51". It is owned and operated by TWP and currently operates under Title V Operating Permit No. P153-R4, which expires on October 14, 2025. The shortest distance to the boundary of the nearest Class I Area, Bosque del Apache Wilderness Area, is approximately 50 miles.

The facility services a natural gas pipeline system, removing small amounts of entrained liquid from the gas stream before directing it back into the pipeline at a higher pressure. The facility is authorized for continuous operation, and its total potential to emit is 2263.5 tons per year of NO_X.[94]

C.4.12.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at MCS. No units met NMED's criteria for requiring an evaluation of potential control measures for SO_2.[95]

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
701	4SLB RICE	Cooper Bessemer LSV-16SG	<1960 (1)	4,500 hp
702	4SLB RICE	Cooper Bessemer LSV-16SG	<1960 (1)	4,500 hp
703	4SLB RICE	Cooper Bessemer LSV-16SG	<1967 (1)	4,500 hp
721	4SRB RICE	Ingersoll Rand PSVG-6	<1960 (1)	335 hp
722	4SRB RICE	Ingersoll Rand PSVG-6	<1960 (1)	335 hp

(1) TWP's most recent Title V permit application does not provide the date of manufacture for any of the units at MCS but does indicate that Units 701, 702, 721, and 722 were constructed/reconstructed in 1960 and Unit 703 was constructed/reconstructed in 1967. The date of manufacture necessarily precedes the construction/reconstruction date.

C.4.12.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. TWP did not request a future utilization adjustment for MCS. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the emissions units at MCS.

NMED calculated baseline actual emissions for the emissions units at MCS by multiplying representative annual operating hours by the NO_X emission rates reported in TWP's most recent periodic emissions test

[94] AQB Title V Operating Permit No. P153-R4, Table 102.A.

[95] See Chapter 6, Selection of Sources for Control Measures Analysis, for a discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.

report(s).[96,] Because the emissions units at MCS operate at varying loads, NMED conservatively adjusted reported emission rates to 100 percent load to represent worst-case emissions.[97] Reported and adjusted emission rates for the emissions units at MCS are summarized below.

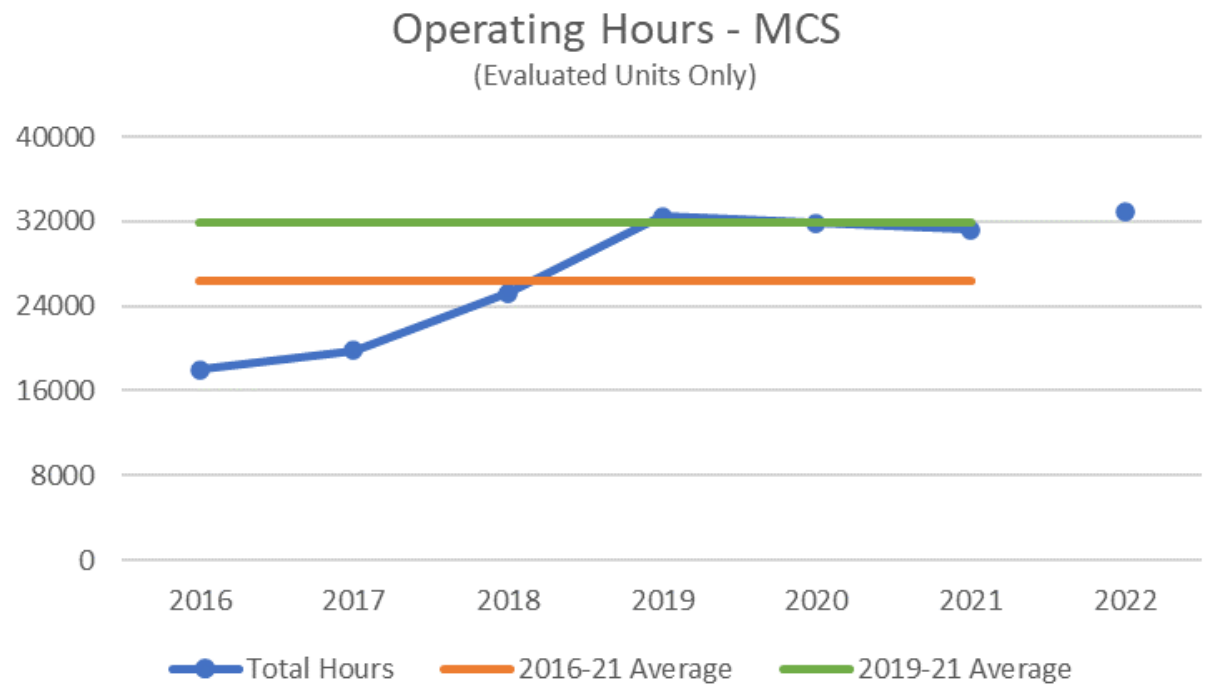
Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr at 100% load)
701	11/8/22	88.9	87%	102.5
702	11/8/22	103.2	88%	116.8
703	11/8/22	95.7	88%	108.4
721	11/8/22	14.1	59%	23.8
722	11/9/22	3.7	58%	6.3

To determine representative annual operating hours for the emissions units at MCS, NMED analyzed 2016-2021 operating hours reported by TWP pursuant to 20.2.73 NMAC. NMED was in receipt of TWP's reported 2022 operating hours at the time of its analysis, but the data were still undergoing internal QA/QC checks and had not been certified yet, so NMED excluded them from its analysis. 2016-2021 operating hours for the emissions units at MCS are summarized and plotted below; reported 2022 operating hours are included for informational purposes only.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
701	1535	2278	5188	7084	7296	7553	8347
702	3116	3046	4615	8491	7572	7607	7352
703	4586	5713	6697	8189	8208	7312	8400
721	3932	2606	4408	1475	1180	28	6034
722	4860	6157	4356	7294	7609	8710	2742

[96] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.

[97] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.



As shown above, MCP's operating hours increased steadily from 2016-2019, then stabilized in 2019 and have been very consistent for the past few years. At a meeting with NMED on 7/11/23, TWP indicated that the recent increase in utilization is due to higher gas volumes and that it expects demand and utilization to remain high "for the foreseeable future." Therefore, NMED determined that 2019-2021 average operating hours are representative for Units 701, 702, and 703. Units 721 and 722 are primary generators (the facility is not connected to an electric utility); per TWP they do not operate simultaneously but one is always in operation. Therefore, they effectively operate as a system, and NMED evaluated them collectively by assuming full time system operation and averaging their emissions.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the emissions units at MCS are summarized below.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
701	102.5	7311	374.4
702	116.8	7980	460.7
703	108.4	7903	428.2
721 & 722	15.1	8760	66.0

C.4.12.4 Technical Feasibility of Available Controls

The following determinations were made regarding the technical feasibility of identified control options for the 4SLB RICE at MCS:

- SNCR and NSCR are not technically feasible options for the same reasons those controls are not feasible for 2SLB RICE.

- GCP is a technically feasible option and is currently utilized by TWP based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- LEC is a technically feasible option expected to achieve a vendor-quoted NO_X emission rate of 2.5 g/hp-hr.
- SCR is a technically feasible option expected to achieve an average NO_X control efficiency of 80 percent.
- Unit replacement is a technically feasible option expected to reduce facility-wide NO_X emissions by 1,284.5 ton/yr, a 97 percent reduction. More information on the replacement scenario evaluated by TWP is provided in Section C.4.12.5.1 below.
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, TWP did not indicate that it intends to permanently retire any of the affected units, so this option is not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and other pollutants).

The following determinations were made regarding the technical feasibility of identified control options for the 4SRB RICE at MCS:

- SCR is not a technically feasible option because the chemical reactions will not occur in an environment with excess oxygen.
- SNCR is not a technically feasible option because the exhaust temperature of the units is too low.
- Electrification is not a technically feasible option because the units are used to generate electricity for the facility.
- NSCR is a technically feasible option and is already installed on both units. As a result, NSCR is not evaluated further.
- GCP is a technically feasible option and is currently utilized by TWP based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- LEC is a technically feasible option expected to achieve a vendor-quoted NO_X emission rate of 2.5 g/hp-hr.
- Unit replacement is a technically feasible option expected to reduce facility-wide NO_X emissions by 1,284.5 ton/yr, a 97 percent reduction. More information on the replacement scenario evaluated by TWP is provided in Section C.4.12.5.1 below.
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, TWP did not indicate that it intends to permanently retire any of the affected units, so this option is not evaluated further.

C.4.12.5 Four-Factor Analysis

In order to determine what control measures are necessary at MCS to make reasonable progress, NMED conducted a FFA of potential control measures for NO_X for the emissions units identified in section C.4.12.2 above. States are required to consider four statutory factors – cost of compliance, time

necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[98]

C.4.12.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X emissions reduced, of each technically feasible control option identified in section C.4.12.4 above. NMED utilized source-specific cost estimates provided by TWP in its calculations whenever possible. In cases where TWP failed to provide source-specific cost estimates or NMED found estimates provided by TWP to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[99]

NMED's cost effectiveness values for all technically feasible controls for the emissions units at MCS are summarized below. NMED believes these values were calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed cost effectiveness calculations for the emissions units at MCS and supporting documentation for NMED's cost estimates are provided in Appendix D.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
701	LEC	$752,925	284.0	$3,000
	SCR	$357,254	299.7	$1,000
702	LEC	$752,925	362.8	$2,000
	SCR	$371,922	368.5	$1,000
703	LEC	$752,925	330.2	$2,000
	SCR	$349,859	342.5	$1,000
721	LEC	$56,051	48.1	$1,000
722	LEC	$56,051	9.8	$6,000
All Units	Replacement	$3,384,865	1284.5	$3,000
	Electrification	$9,341,163	1329.5	$7,000

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the emissions units at MCS:

- The bank prime rate (7.5 percent as of December 2024) was used to determine the appropriate capital recovery factor. TWP indicated that the prime rate is appropriate for the purposes of NMED's analysis in its 8/11/23 submittal.

[98] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).

[99] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

- The Total Capital Investment (TCI) of a 2SLB RICE LEC retrofit was provided by TWP based on a detailed cost estimate provided by a vendor. NMED estimated the TCI of a 4SRB RICE LEC retrofit using the 2SLB estimate scaled by engine power rating.
- The Total Capital Costs (TCC), Direct Annual Costs (DAC), and Indirect Annual Costs (OAC) of SCR were calculated using EPA's SCR Tool. An SCR retrofit factor of 1 (average difficulty) was applied, which appears to be consistent with the SCR evaluations provided in TWP's initial FFA.
- TWP indicated that replacing the 2SLB RICE with CT would be preferable to replacing them with new RICE. Therefore, instead of evaluating replacing Units 701, 702, and 703 with like-kind units, NMED evaluated replacing them with two functionally equivalent CT using detailed capital and O&M cost information provided by TWP. TWP indicated that this would also require replacing Units 721 and 722 with microturbine generators to meet the new demand and reliability requirements associated with the installation of CT but did not provide any cost information for new generators. Therefore, NMED estimated these costs using EPA's Catalog of CHP Technologies, Section 5. Technology Characterization – Microturbines (March 2015).
- TWP provided detailed capital and O&M cost information for the electrification of Units 701, 702, and 703. TWP indicated that electrifying MCS would also require a new substation and at least 8 miles of new transmission line to connect to the local utility but did not provide any cost information for these upgrades due to its inability to obtain estimates from the utility. Therefore, NMED estimated these costs using information provided by other facilities.

C.4.12.5.2 Compliance Time

TWP indicated it would take 2-5 years to implement LEC or SCR at the facility. This estimate is consistent with NMED's general assessment of compliance times and thus believed to be reasonably accurate.

TWP did not provide information regarding the time necessary to replace their RICE units with CT as described above. NMED believes the general compliance time for replacement, provided in Section C.3.4, is reasonable but recognizes additional time could be required considering the inability of the facility to take Units 701, 702, and 703 out of service for the replacement,[100] and thus the need to build new facilities and infrastructure within the station and switch over operation once construction is complete.

TWP did not provide information regarding the time necessary for electrification. NMED believes the general compliance time for electrification, provided in Section C.3.4, is reasonable but recognizes several more years could be required considering the inability of the facility to take the existing units out of service for the replacement and the relative complexity of the needed utility upgrades.

C.4.12.5.3 Remaining Useful Life

Despite the advanced age of the units at MCS (~50 to 60 years), owners and operators of gas compression equipment in New Mexico have indicated that similar RICE would last at least 20 more years with proper maintenance. Twenty years is thus the estimated remaining useful life for LEC.

[100] In its 8/11/23 submittal, TWP indicated that current firm shipping contracts require full utilization of compression horsepower at MCS.

Consistent with generally accepted EPA methodology and NMED's experience, the useful life of SCR is estimated to be 20 years.

Manufacturers of new CT will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new CT are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement CT is 30 years.

There is limited information about the useful life of EMD units, but research suggests the useful life is at least 25 years.

C.4.12.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for 4SLB RICE and 4SRB RICE is provided in Sections C.3.2 and C.3.3, respectively.

C.4.12.5.5 Summary

NMED performed a FFA for all technically feasible control options for NO_X for the units listed in Section C.4.12.2 above. The four statutory factors are discussed in Sections C.4.12.5.1 through C.4.12.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
701	LEC	$3,000	2-5	20	None
	SCR	$1,000	2-5	20	None
702	LEC	$2,000	2-5	20	None
	SCR	$1,000	2-5	20	None
703	LEC	$2,000	2-5	20	None
	SCR	$1,000	2-5	20	None
721	LEC	$1,000	2-5	20	None
722	LEC	$6,000	2-5	20	None
All Units	Replacement	$3,000	3-4	30	None
	Electrification	$7,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

C.4.12.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze

Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[101]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For emissions units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For emissions units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective control is necessary to make reasonable progress. The sole exception to these general rules is the categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

NMED's FFA identified cost-effective controls for MCS Units 701, 702, 703, 721, and 722. Based on its analysis of the four statutory factors and the decision-making criteria described above, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
701	Replacement	362.0
702	Replacement	445.1
703	Replacement	413.7
721	Replacement	50.3
722	Replacement	13.4

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
701	LEC	Less stringent than replacement
701	SCR	Less stringent than replacement
701	Electrification	Categorically excluded
702	LEC	Less stringent than replacement
702	SCR	Less stringent than replacement
702	Electrification	Categorically excluded
703	LEC	Less stringent than replacement
703	SCR	Less stringent than replacement
703	Electrification	Categorically excluded
721	LEC	Less stringent than replacement
722	LEC	Less stringent than replacement

Based on the expected reductions from the controls NMED has determined are necessary to make reasonable progress, NMED estimates the total emissions reductions at MCS during the second planning period will be approximately 1,284.5 ton/yr of NO_X.

[101] See *supra* note 13.

C.4.13 Transwestern Pipeline Company – Roswell Compressor Station No. 9

Resources used in NMED's FFA for Roswell Compressor Station No. 9 (RCS) include, but are not limited to, the following:

- The FFA completed by GHD Services, Inc. for Transwestern Pipeline Company, LLC (TWP) and submitted to NMED on 10/30/19.
- Additional information provided by TWP on 01/23/20, 09/10/20, 3/25/21, and 8/11/23.
- Detailed discussions between TWP and NMED on 7/11/23 and 7/21/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP region (March 23, 2020)
- FFAs developed for similar facilities in New Mexico and other states.

C.4.13.1 Facility Description

RCS is a natural gas compressor station located 5 miles north of Roswell in Chaves County, New Mexico at latitude 33° 30' 37", longitude -104° 31' 08". It is owned and operated by TWP and currently operates under Title V Operating Permit No. P154-R4, which expired on September 28, 2023.[102] The shortest distance to the boundary of the nearest Class I Area, Salt Creek Wilderness Area, is approximately 5.6 miles. Notably, Salt Creek Wilderness Area is the only Class I Area in New Mexico projected to be above the URP glidepath in 2028 and for which a robust demonstration is required.[103]

The facility services a natural gas pipeline system, removing small amounts of entrained liquid from the gas stream before directing it back into the pipeline at a higher pressure. The facility is authorized for continuous operation, and its total potential to emit is 1122.5 tons per year of NO_X and 0.8 tons per year of SO_2.[104]

C.4.13.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at RCS. No units met NMED's criteria for requiring an evaluation of potential control measures for SO_2.[105]

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[102] Transwestern Pipeline Company, LLC submitted a timely application to renew Title V Operating Permit No. P154-R4 in September 2022. At the time of preparation of this technical support document, NMED had not taken final action on the application. Pursuant to 20.2.70.201 NMAC, a Title V source may continue to operate after its operating permit expires if it has submitted a timely renewal application and meets other requirements.

[103] See Chapter 10, Progress, Degradation, and URP Glidepath Checks for Class I Areas in New Mexico, for NMED's robust demonstration for Salt Creek Wilderness Area.

[104] AQB Title V Operating Permit No. P154-R4, Table 102.A.

[105] See Chapter 6, Selection of Sources for Control Measures Analysis, for a discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
903	4SLB RICE	Cooper Bessemer LSV-16SSG	1959	4,500 hp
904	4SLB RICE	Cooper Bessemer LSV-16SSG	1959	4,500 hp

C.4.13.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. TWP did not request a future utilization adjustment for RCS. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the emissions units at RCS.

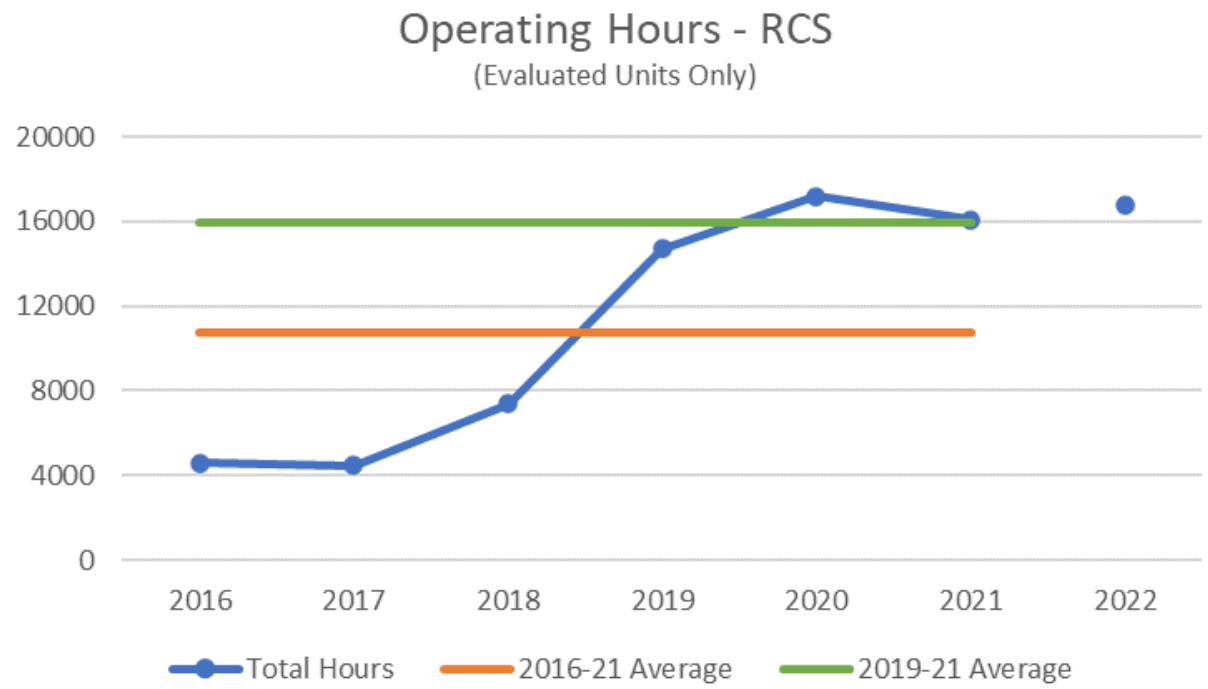
NMED calculated baseline actual emissions for the emissions units at RCS by multiplying representative annual operating hours by the NO_X emission rates reported in TWP's most recent periodic emissions test report(s).[106,] Because the emissions units at RCS operate at varying loads, NMED conservatively adjusted reported emission rates to 100 percent load to represent worst-case emissions.[107] Reported and adjusted emission rates for the emissions units at RCS are summarized below.

Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr at 100% load)
903	2/27/23	106.1	95%	111.3
904	2/27/23	53.4	97%	54.8

To determine representative annual operating hours for the emissions units at RCS, NMED analyzed 2016-2021 operating hours reported by TWP pursuant to 20.2.73 NMAC. NMED was in receipt of TWP's reported 2022 operating hours at the time of its analysis, but the data were still undergoing internal QA/QC checks and had not been certified yet, so NMED excluded them from its analysis. 2016-2021 operating hours for the emissions units at RCS are summarized and plotted below; reported 2022 operating hours are included for informational purposes only.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
903	3607	3220	6343	8079	8696	8217	8303
904	971	1231	1049	6652	8490	7843	8476

[106] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.
[107] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.



As shown above, RCS's operating hours increased steadily from 2016-2019, then remained fairly consistent from 2019-2021. At a meeting with NMED on 7/11/23, TWP indicated that the recent increase in utilization is due to higher gas volumes and that it expects demand and utilization to remain high "for the foreseeable future." Therefore, NMED determined that 2019-2021 average operating hours are representative for the emissions units at RCS.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the emissions units at RCS are summarized below.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
903	111.3	8331	463.7
904	54.8	7662	210.0

C.4.13.4 Technical Feasibility of Available Controls

The following determinations were made regarding the technical feasibility of identified control options for the 4SLB RICE at RCS:

- SNCR and NSCR are not technically feasible options for the same reasons those controls are not feasible for 2SLB RICE.
- GCP is a technically feasible option and is currently utilized by TWP based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- LEC is a technically feasible option expected to achieve a vendor-quoted NO_X emission rate of 2.5 g/hp-hr.

- SCR is a technically feasible option expected to achieve an average NO_X control efficiency of 80 percent.
- Unit replacement is a technically feasible option expected to reduce facility-wide NO_X emissions by 644.6 ton/yr, a 96 percent reduction. More information on the replacement scenario evaluated by TWP is provided in Section C.4.13.5.1 below.
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, TWP did not indicate that it intends to permanently retire any of the affected units, so this option is not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants).

C.4.13.5 Four-Factor Analysis

In order to determine what control measures are necessary at RCS to make reasonable progress, NMED conducted a FFA of potential control measures for NO_X for the emissions units identified in section C.4.13.2 above. States are required to consider four statutory factors – cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[108]

C.4.13.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X emissions reduced, of each technically feasible control option identified in section C.4.13.4 above. NMED utilized source-specific cost estimates provided by TWP in its calculations whenever possible. In cases where TWP failed to provide source-specific cost estimates or NMED found estimates provided by TWP to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[109]

NMED's cost effectiveness values for all technically feasible controls for the emissions units at RCS are summarized below. NMED believes these values were calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed cost effectiveness calculations for the emissions units at RCS and supporting documentation for NMED's cost estimates are provided in Appendix D.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
903	LEC	$693,810	360.3	$2,000
	SCR	$339,730	370.9	$1,000
904	LEC	$693,810	115.0	$6,000

[108] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).

[109] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
	SCR	$306,279	168.0	$2,000
All Units	Replacement	$2,231,087	644.6	$3,000
	Electrification	$6,272,562	673.7	$9,000

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the emissions units at RCS:

- The bank prime rate (7.5 percent as of December 2024) was used to determine the appropriate capital recovery factor. TWP indicated that the prime rate is appropriate for the purposes of NMED's analysis in its 8/11/23 submittal.
- The Total Capital Investment (TCI) of a LEC retrofit was provided by TWP based on a detailed cost estimate provided by a vendor.
- The Total Capital Costs (TCC), Direct Annual Costs (DAC), and Indirect Annual Costs (OAC) of SCR were calculated using EPA's SCR Tool. An SCR retrofit factor of 1 (average difficulty) was applied, which appears to be consistent with the SCR evaluations provided in TWP's initial FFA.
- TWP indicated that replacing the 4SLB RICE with CT would be preferable to replacing them with new RICE. Therefore, instead of evaluating replacing Units 903 and 904 with like-kind units, NMED evaluated replacing them with a functionally equivalent CT using detailed capital and O&M cost information provided by TWP.
- TWP provided detailed capital and O&M cost information for the electrification of Units 903 and 904. TWP indicated that electrifying RCS would also require substation and transmission line upgrades but did not provide any cost information for these upgrades due to its inability to obtain estimates from the utility. Therefore, NMED estimated these costs using information provided by other facilities.

C.4.13.5.2 Compliance Time

TWP indicated it would take 2-5 years to implement LEC or SCR at the facility. This estimate is consistent with NMED's general assessment of compliance times and thus believed to be reasonably accurate.

TWP did not provide information regarding the time necessary to replace their RICE units with a CT as described above. NMED believes the general compliance time for replacement, provided in Section C.3.4, is reasonable but recognizes additional time could be required considering the inability of the facility to take Units 903 and 904 out of service for the replacement,[110] and thus the need to build new facilities and infrastructure within the station and switch over operation once construction is complete.

TWP did not provide information regarding the time necessary for electrification. NMED believes the general compliance time for electrification, provided in Section C.3.4, is reasonable but recognizes several more years could be required considering the inability of the facility to take the existing units out of service for the replacement and the relative complexity of the needed utility upgrades.

[110] In its 8/11/23 submittal, TWP indicated that current firm shipping contracts require full utilization of compression horsepower at RCS.

C.4.13.5.3 Remaining Useful Life

Despite the advanced age of the units at RCS (~60 years), owners and operators of gas compression equipment in New Mexico have indicated that similar RICE would last at least 20 more years with proper maintenance. Twenty years is thus the estimated remaining useful life for LEC.

Consistent with generally accepted EPA methodology and NMED's experience, the useful life of SCR is estimated to be 20 years.

Manufacturers of new CT will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new CT are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement CT is 30 years.

There is limited information about the useful life of EMD units, but research suggests the useful life is at least 25 years.

C.4.13.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for 4SLB RICE is provided in Section C.3.2.

C.4.13.5.5 Summary

NMED performed a FFA for all technically feasible control options for NO_X for the units listed in Section C.4.13.2 above. The four statutory factors are discussed in Sections C.4.13.5.1 through C.4.13.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
903	LEC	$2,000	2-5	20	None
	SCR	$1,000	2-5	20	None
904	LEC	$6,000	2-5	20	None
	SCR	$2,000	2-5	20	None
All Units	Replacement	$3,000	3-4	30	None
	Electrification	$9,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

C.4.13.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making

reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[111]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For emissions units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For emissions units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective control is necessary to make reasonable progress. The sole exception to these general rules is the categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

NMED's FFA identified cost-effective controls for RCS Units 903 and 904. Based on its analysis of the four statutory factors and the decision-making criteria described above, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
903	Replacement	443.7
904	Replacement	201.0

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
903	LEC	Less stringent than replacement
903	SCR	Less stringent than replacement
903	Electrification	Categorically excluded
904	LEC	Less stringent than replacement
904	SCR	Less stringent than replacement
904	Electrification	Categorically excluded

Based on the expected reductions from the controls NMED has determined are necessary to make reasonable progress, NMED estimates the total emissions reductions at RCS during the second planning period will be approximately 644.7 ton/yr of NO_X.

C.4.14 Harvest Four Corners – Kutz Canyon Processing Plant

Resources used in NMED's FFA for Kutz Canyon Processing Plant (KCPP) include, but are not limited to, the following:

- The FFA completed by Trinity Consultants for Harvest Four Corners, LLC (Harvest) and submitted to NMED on or about 11/1/19.

[111] See *supra* note 13.

- Additional information provided by Harvest on 12/13/19, 3/2/20, 10/23/20, 2/26/21, 8/28/23, 2/22/24, and 3/27/24.
- Detailed discussions between Harvest and NMED, most recently on 7/11/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP region (March 23, 2020)
- FFAs developed for similar facilities in New Mexico and other states.

C.4.14.1 Facility Description

KCPP is a natural gas processing facility located approximately 3.5 miles south of Bloomfield in San Juan County, New Mexico at latitude 36° 40' 11", longitude -107° 57' 42". It is owned and operated by Harvest and currently operates under Title V Operating Permit No. P097-R4, which expires on January 3, 2028. The shortest distance to the boundary of the nearest Class I Area, Mesa Verde National Park, is approximately 43.2 miles.

The function of the facility is to remove ethane and heavier hydrocarbons from natural gas through refrigerating lean oil absorption and cryogenic processes. The facility is authorized for continuous operation, and its total potential to emit is 603.3 tons per year of NO_X and 1.4 tons per year of SO_2.[112]

C.4.14.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at KCPP. No units met NMED's criteria for requiring an evaluation of potential control measures for SO_2.[113]

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
1	Turbine	Solar Centaur 40	7/1/1975	3,692 hp
2	Turbine	Solar Centaur 40	7/1/1975	3,692 hp
3	Turbine	Solar Centaur 40	7/1/1975	3,692 hp
4	Turbine	Solar Centaur 40	7/1/1975	3,692 hp
5	Turbine	Solar Centaur 40	10/1/1975	3,692 hp
6	Turbine	Solar Centaur 40	10/1/1975	3,692 hp
16	4SRB RICE	Clark HRA-8	<1973	723 hp
17	4SRB RICE	Clark HRA-8	<1973	723 hp
18	4SRB RICE	Clark HRA-8	<1973	723 hp

[112] AQB Title V Operating Permit No. P097-R4, Table 102.A.

[113] See Chapter 6, Selection of Sources for Control Measures Analysis, for a detailed discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
19	Turbine	Solar Centaur 40	6/1/1981	2,907 hp
20	Turbine	Solar Centaur 40	7/1/1981	2,907 hp

After it submitted its FFA in November 2019, Harvest retired Units 16, 17 and 18 and removed them from KCPP's NSR permit. Therefore, NMED did not evaluate these units.

C.4.14.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. Harvest did not request a future utilization adjustment for KCPP. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the emissions units at KCPP.

NMED calculated baseline actual emissions for the emissions units at KCPP by multiplying representative annual operating hours by the NO_X emission rates reported in Harvest's most recent periodic emissions test report(s).[114,] Because the emissions units at KCPP operate at varying loads, NMED conservatively adjusted reported emission rates to 100 percent load to represent worst-case emissions.[115] Reported and adjusted emission rates for the emissions units at KCPP are summarized below.

Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr @ 100% load)
1	6/20/23	13.36	80%	16.7
2	6/20/23	14.15	80%	17.7
3	6/22/23	9.80	78%	12.6
4	NA (1)	---	---	14.1 (2)
5	5/26/22	11.66	98%	11.9
6	5/26/22	11.53	98%	11.8
19	6/22/23	4.56	9%	15.6 (3)
20	6/22/23	4.04	10%	15.6 (3)

(1) NA = Not Available

(2) The average adjusted emissions of identical Units 1-3 and 5-6 were used as a surrogate for Unit 4, as NMED was unable to locate a recent emissions test report for this unit.

(3) The most recent testing of Units 19 and 20 was conducted at very low load. Therefore, instead of adjusting reported emissions to 100 percent load based on an assumed linear relationship between emissions and load, NMED used a surrogate emission factor based on the heat input capacity (MMBtu/hr) of these units and a vendor-provided emission rate expressed in lb/MMBtu.

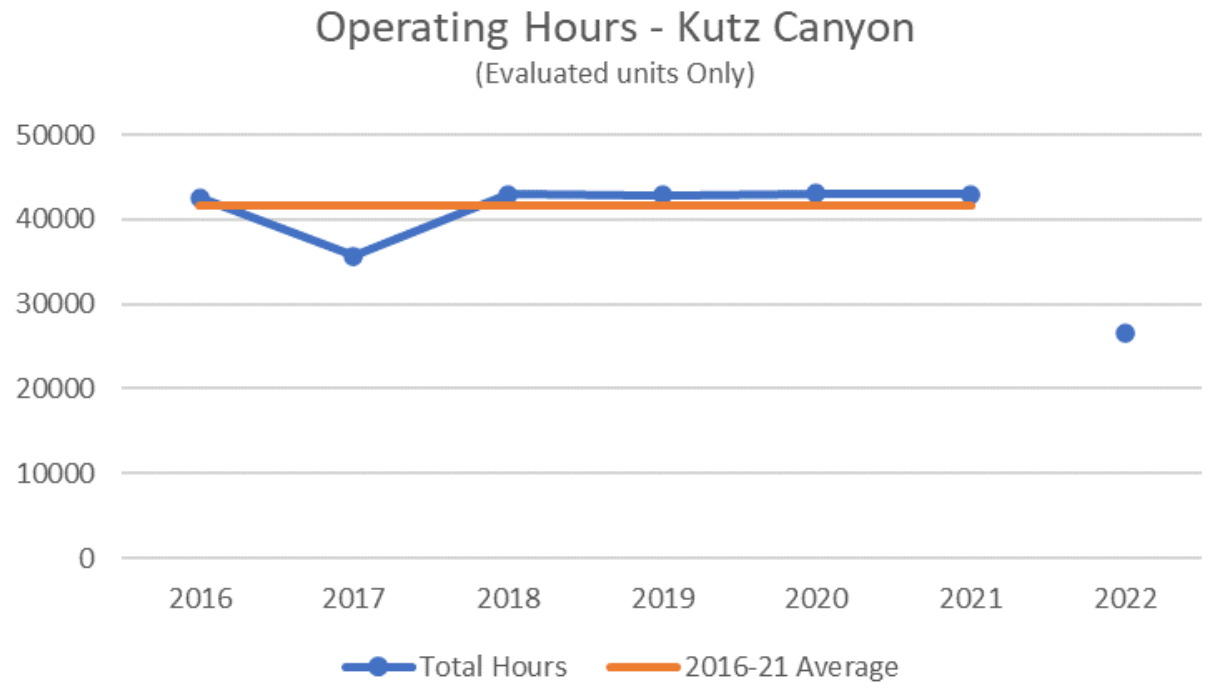
To determine representative annual operating hours for the emissions units at KCPP, NMED analyzed 2016-2021 operating hours reported by Harvest pursuant to 20.2.73 NMAC. NMED was in receipt of Harvest's reported 2022 operating hours at the time of its analysis, but the data were still undergoing internal QA/QC checks and had not been certified yet, so NMED excluded them from its analysis. 2016-

[114] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.

[115] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.

2021 operating hours for the emissions units at KCPP are summarized and plotted below; reported 2022 operating hours are included for informational purposes only.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
1	5616	6784	8418	7711	6724	6389	7096
2	5228	5131	5550	6020	5048	5271	7858
3	6360	5910	2937	3917	5882	6042	2975
4	694	649	927	0	0	0	0
5	7479	718	8368	8298	8606	8076	0
6	8397	7752	8020	8128	8581	8463	0
19	2639	3774	6989	6513	4943	4016	4504
20	6172	5009	1777	2265	3333	4748	4257



As shown above, KCPP's year-over-year operating hours have been very consistent in recent years, with no discernible impact from the pandemic in 2020. 2017 was an anomaly due to a roughly 90 percent drop in operating hours for Unit 5. However, NMED suspects this may have been a reporting error, and in any event, operating hours for Unit 5 rebounded the following year and have remained steady ever since. Therefore, NMED determined that 2016-2021 average operating hours are representative for the emissions units at KCPP.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the emissions units at KCPP are summarized below.

Unit No.	Adjusted Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual Emissions (ton/yr)
1	16.7	6940	58.0
2	17.7	5375	47.5
3	12.6	5175	32.5
4	14.1	6257 [(1)]	46.1
5	11.9	6924	41.2
6	11.8	8224	48.4
19	15.6	4812	37.6
20	15.6	3884	30.3

[(1)] Unit 4 has not operated since 2018, skewing its 2016-21 average operating hours. Therefore, the average 2016-21 average operating hours of identical Units 1, 2, 3, 5, and 6 were used as a surrogate for Unit 4.

C.4.14.4 Technical Feasibility of Available Controls

As indicated in Section C.3.4, the following determinations were made regarding the technical feasibility of identified control options for the CT at KCPP:

- WSI, SNCR, and NSCR are not technically feasible options.
- GCP is a technically feasible option and is currently utilized by Harvest based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- DLN is a technically feasible option expected to achieve a vendor-quoted NO_X emission rate of 25 ppm.
- SCR is a technically feasible option expected to achieve an average NO_X control efficiency of 80 percent.
- Unit replacement is a technically feasible option. Because a DLN retrofit option is available for the make and model of CT comprising the existing units, it is assumed that DLN would be available on equivalent replacements. Therefore, replacement is expected to achieve a NO_X emission rate of 25 ppm, consistent with manufacturer specifications for similar, new CT equipped with DLN.
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, Harvest did not indicate that it intends to permanently retire any of the affected units, so this option is not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants).

C.4.14.5 Four-Factor Analysis

In order to determine what control measures are necessary at KCPP to make reasonable progress, NMED conducted a FFA of potential control measures for NO_X for the emissions units identified in section C.4.14.2 above. States are required to consider four statutory factors – cost of compliance, time

necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[116]

C.4.14.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X emissions reduced, of each technically feasible control option identified in section C.4.14.4 above. NMED utilized source-specific cost estimates provided by Harvest in its calculations whenever possible. In cases where Harvest failed to provide source-specific cost estimates or NMED found estimates provided by Harvest to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[117]

NMED's cost effectiveness values for all technically feasible controls for the emissions units at KCPP are summarized below. NMED believes these values were calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed cost effectiveness calculations for the emissions units at KCPP and supporting documentation for NMED's cost estimates are provided in Appendix D.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
1	SCR	$294,770	46.4	$6,000
	DLN	$235,465	41.3	$6,000
	Replacement	$1,109,121	41.3	$27,000
2	SCR	$290,003	38.0	$8,000
	DLN	$228,625	33.4	$7,000
	Replacement	$1,109,121	33.4	$33,000
3	SCR	$287,133	26.0	$11,000
	DLN	$228,625	20.5	$11,000
	Replacement	$1,109,121	20.5	$54,000
4	SCR	$292,031	36.9	$8,000
	DLN	$228,625	29.0	$8,000
	Replacement	$1,109,121	29.0	$38,000
5	SCR	$292,033	33.0	$9,000
	DLN	$228,625	24.9	$9,000
	Replacement	$1,109,121	24.9	$45,000
6	SCR	$295,792	38.7	$8,000
	DLN	$228,625	14.7	$16,000

[116] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).

[117] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
	Replacement	$1,109,121	14.7	$76,000
19	SCR	$246,303	30.1	$8,000
	DLN	$234,892	23.7	$10,000
	Replacement	$885,804	23.7	$37,000
20	SCR	$243,698	24.3	$10,000
	DLN	$229,425	19.1	$12,000
	Replacement	$885,804	19.1	$46,000
All Units	Electrification	$6,094,068	341.6	$18,000

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the emissions units at KCPP:

- Harvest provided a company-specific cost of capital (7.5 percent) in its 8/28/23 submittal.
- Harvest provided an estimate of the Total Capital Investment (TCI) and Incremental Annual O&M Costs (OMC) associated with electrification in its 10/23/20 submittal. That estimate included approximately $20M for a new electric substation.
- According to Harvest, the TCI and Incremental Annual Costs for DLN were based on information provided by a vendor, Solar Turbines.
- Harvest asserted there is insufficient space to accommodate SCR at KCPP. However, Harvest did not provide sufficient documentation in support of this assertion, so NMED evaluated the cost effectiveness of SCR. The Total Capital Costs (TCC), Direct Annual Costs (DAC), and Indirect Annual Costs (OAC) of SCR were calculated using EPA's SCR Tool. An SCR retrofit factor of 1 (average difficulty) was applied, due to a lack of information from Harvest supporting a higher retrofit factor.
- Harvest, like most of the companies required to submit a FFA, did not provide information regarding the TCI associated with the replacement of the CT units at KCPP with new, functionally equivalent natural gas-fired units. NMED reviewed several publicly available resources with information that could be used to estimate the TCI of a replacement CT[118] along with information provided by other companies with similar units. NMED determined that the most applicable cost metric ($ per hp basis) was provided by El Paso Natural Gas Company in support of their FFA submittals. NMED understands that the use of this metric is likely accurate to within ±30 percent, but also recognizes that various preliminary vendor quotes are often caveated with a similar degree of accuracy.

C.4.14.5.2 Compliance Time

Harvest indicated it would take 2-3 years to implement DLN on the CT at KCPP. Based on information provided by other facilities and other resources, NMED believes this timeframe is reasonable.

[118] This includes, but is not limited to, the U.S. EPA's Combined Heat and Power Catalog of Technologies (Combustion Turbines) and the U.S. Energy Information Agency's *Cost and Performance Characteristics of New Generating Technologies* in the 2023 Annual Energy Outlook.

Harvest did not provide an estimate of the time necessary to implement SCR. NMED believes the general compliance time provided in Section C.3.4 is reasonable.

Harvest also did not provide an estimate of the time necessary to replace the CT at KCPP. NMED believes the general compliance times for replacement with new, functionally equivalent natural gas-fired CT or EMD provided in Section C.3.4 are reasonable but recognizes that in the case of EMD several more years could be required considering the relative complexity.

C.4.14.5.3 Remaining Useful Life

Despite the advanced age of the CT at KCPP (~40 to 50 years), owners and operators of gas compression equipment in New Mexico have indicated that similar CT would last at least 20 more years with proper maintenance. Twenty years is thus the estimated remaining useful life for DLN.

Manufacturers of new CT will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new CT are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement CT is 30 years.

Consistent with generally accepted EPA methodology and NMED's experience, the useful life of SCR is estimated to be 20 years.

There is limited information about the useful life of EMD units, but research suggests the useful life is at least 25 years.

C.4.14.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for CT is provided in Section C.3.4.

C.4.14.5.5 Summary

NMED performed a FFA for all technically feasible control options for NO_X for the units listed in Section C.4.14.2 above. The four statutory factors are discussed in Sections C.4.14.5.1 through C.4.14.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
1	SCR	$6,000	3-4	20	None
	DLN	$6,000	2-3	20	None
	Replacement	$27,000	3-4	30	None
2	SCR	$8,000	3-4	20	None
	DLN	$7,000	2-3	20	None
	Replacement	$33,000	3-4	30	None
3	SCR	$11,000	3-4	20	None
	DLN	$11,000	2-3	20	None
	Replacement	$54,000	3-4	30	None

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
4	SCR	$8,000	3-4	20	None
	DLN	$8,000	2-3	20	None
	Replacement	$38,000	3-4	30	None
5	SCR	$9,000	3-4	20	None
	DLN	$9,000	2-3	20	None
	Replacement	$45,000	3-4	30	None
6	SCR	$8,000	3-4	20	None
	DLN	$16,000	2-3	20	None
	Replacement	$76,000	3-4	30	None
19	SCR	$8,000	3-4	20	None
	DLN	$10,000	2-3	20	None
	Replacement	$37,000	3-4	30	None
20	SCR	$10,000	3-4	20	None
	DLN	$12,000	2-3	20	None
	Replacement	$46,000	3-4	30	None
All Units	Electrification	$18,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

C.4.14.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[119]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For emissions units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For emissions units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective control is necessary to make reasonable progress. The sole exception to these general rules is the categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

[119] See *supra* note 13.

NMED's FFA identified cost effective controls for KCPP Units 1, 2, 4, 5, 6, 19, and 20. Based on its analysis of the four statutory factors and the decision-making criteria described above, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
1	SCR	46.4
2	SCR	38.0
4	SCR	36.9
5	SCR	33.0
6	SCR	38.7
19	SCR	30.1
20	SCR	24.3

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
1	DLN	Less stringent than SCR
2	DLN	Less stringent than SCR
4	DLN	Less stringent than SCR
5	DLN	Less stringent than SCR
19	DLN	Less stringent than SCR

NMED's FFA did not identify any cost-effective controls for KCPP Unit 3. Therefore, NMED determined that reasonable progress does not require new controls on this unit. As noted above, NMED did not conduct a FFA of potential control measures for Units 16, 17, and 18 because they have been permanently shut down and removed from KCPP's NSR permit. However, based on when they were retired, the resulting emissions reductions were realized during the second planning period. Therefore, NMED estimated the NO_X emissions reductions resulting from the retirement of these units by averaging 2016-2020 emissions reported by Harvest pursuant to 20.2.73 NMAC. These emissions are summarized below.

Unit No.	Estimated NO_X Reductions (ton/yr)
16	93.6
17	62.7
18	89.1

Combining expected reductions from the controls NMED has determined are necessary to make reasonable progress and reductions resulting from recent retirements, NMED estimates the total emissions reductions at KCPP during the second planning period will be approximately 492.8 ton/yr of NO_X.

C.4.15 Hilcorp Energy Company – San Juan Basin Gas Plant

Resources used in NMED's FFA for San Juan Basin Gas Plant (SJBGP) include, but are not limited to, the following:

- The FFA completed by Trinity Consultants for Harvest Four Corners, LLC (Harvest) and submitted to NMED on or about 11/1/19.
- Additional information provided by Harvest on 12/13/19, 3/2/20, 10/23/20, and 2/26/21.
- Additional information provided by successor owner Hilcorp Energy Company (Hilcorp) on 7/31/2023.[120]
- A detailed discussion between Hilcorp and NMED on 6/2/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP region (March 23, 2020)
- FFAs developed for similar facilities in New Mexico and other states.

C.4.15.1 Facility Description

SJBGP is a natural gas processing facility located approximately 2 miles northeast of Bloomfield in San Juan County, New Mexico at latitude 36° 43' 57", longitude -107° 57' 59". It is owned and operated by Hilcorp and currently operates under Title V Operating Permit No. P124-R4, which expires on March 10, 2028. The shortest distance to the boundary of the nearest Class I Area, Mesa Verde National Park, is approximately 39.6 miles.

The function of the facility is to extract and process natural gas liquids and residue gas products from field gas. The facility is authorized for continuous operation, and its total potential to emit is 1050.1 tons per year of NO_X and 18.3 tons per year of SO_2.[121]

C.4.15.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at SJBGP:[122]

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
1	Turbine	Rolls Royce Avon 1535	1985/1986 (1)	15,000 hp
2	Turbine	Rolls Royce Avon 1535	1985/1986 (1)	15,000 hp
3	Turbine	Rolls Royce Avon 1535	1985/1986 (1)	15,000 hp
4	Turbine	Solar Centaur T4501	1986	3,735 hp
5	Turbine	Solar Centaur T4501	1986	3,735 hp
6	Turbine	Solar Centaur T4501	1986	3,735 hp

[120] SJBGP underwent a change of ownership, from Harvest Four Corners, LLC to Hilcorp Energy Company, in 2021.
[121] AQB Title V Operating Permit No. P124-R4, Table 102.A.
[122] See Chapter 6, Selection of Sources for Control Measures Analysis, for a detailed discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
7	Turbine	Solar Centaur T4501	1986	3,735 hp

(1) Units 1, 2 and 3 may be any one of four unique turbines. Up to three of these turbines operate at any time, with the fourth held in maintenance reserve. One of these turbines was manufactured in 1985, and the rest in 1986.

NMED also elected to evaluate the ATS at SJBGP for potential control measures for SO_2 due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). The ATS at SJBGP consists of an ATU (Unit Amine Unit), TO (Unit 15), and two flares (Units 9 and 16). During normal operations, acid gas exiting the ATU is routed to the TO for disposal. During TO SSM/M events, acid gas is rerouted to the backup flare system for disposal.[123]

C.4.15.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. Hilcorp did not request a future utilization adjustment for SJBGP. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the emissions units at SJBGP.

For the emissions units at SJBGP requiring a FFA of potential control measures for NO_X ("NO_X units"), NMED calculated baseline actual emissions by multiplying representative annual operating hours by the NO_X emission rates reported in Hilcorp's most recent periodic emissions test report(s).[124,] Because the NO_X units at SJBGP operate at varying loads, NMED conservatively adjusted reported emission rates to 100 percent load to represent worst-case emissions.[125] Reported and adjusted emission rates for the NO_X units at SJBGP are summarized below.

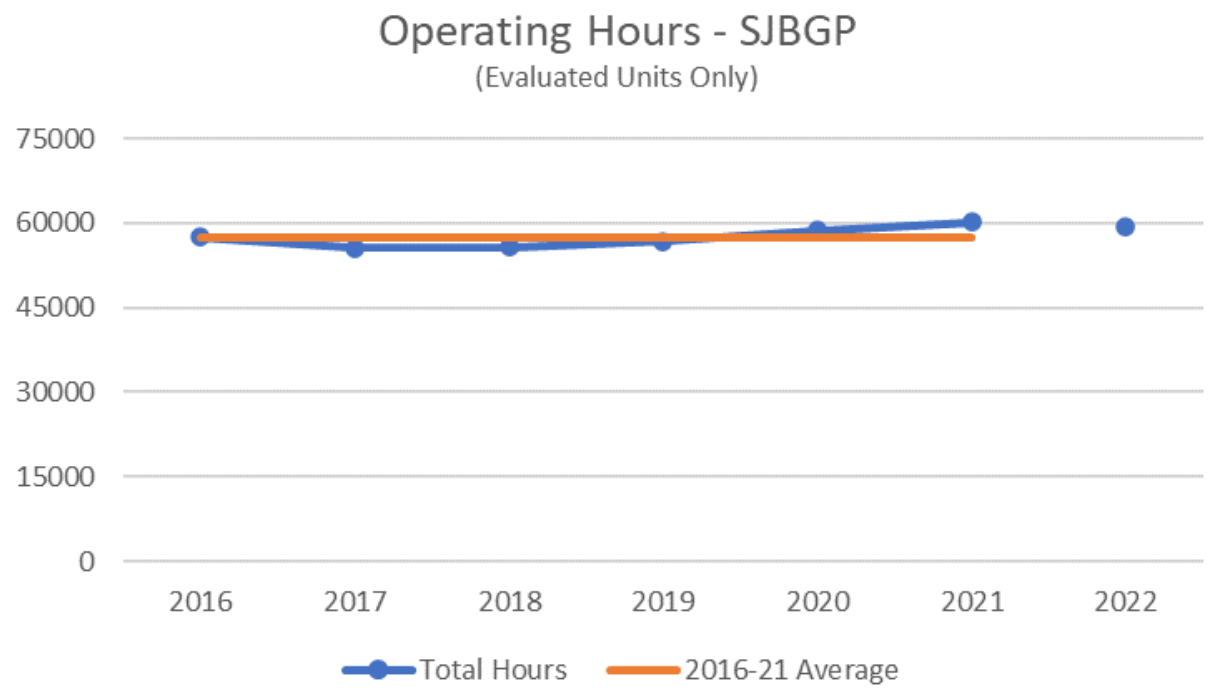
Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr @ 100% load)
1	6/7/22	18.7	94%	19.8
2	6/7/22	19.8	93%	21.2
3	6/7/22	18.4	94%	19.4
4	6/8/22	13.6	98%	13.9
5	6/8/22	12.7	93%	13.7
6	6/8/22	14.4	95%	15.2
7	6/8/22	13.3	92%	14.4

To determine representative annual operating hours for the NO_X units at SJBGP, NMED analyzed 2016-2021 operating hours reported by Hilcorp pursuant to 20.2.73 NMAC. NMED was in receipt of Hilcorp's reported 2022 operating hours at the time of its analysis, but the data were still undergoing internal

[123] When acid gas from the ATU is rerouted to the flare system, Unit 16 is used and Unit 9 remains closed until Unit 16 reaches its maximum flow, at which point Unit 16 is closed and the gas rerouted to Unit 9.
[124] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.
[125] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.

QA/QC checks and had not been certified yet, so NMED excluded them from its analysis. 2016-2021 operating hours for the NO_X units at SJBGP are summarized and plotted below; reported 2022 operating hours are included for informational purposes only.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
1	8289	8427	8555	8312	8494	8507	8436
2	8164	8623	8517	8544	8571	8654	8315
3	8318	8622	8572	8556	8575	8680	8489
4	7877	7770	7328	7931	8575	8561	8445
5	8273	6904	8155	8201	8139	8670	8551
6	8468	7038	7782	7595	8678	8543	8397
7	8215	8231	6789	7687	7710	8651	8625



As shown above, year-over-year operating hours for the NO_X units at SJBGP have been very consistent in recent years, with no discernible impact from the pandemic in 2020. Therefore, NMED determined that 2016-2021 average operating hours are representative for these units.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the NO_X units at SJBGP are summarized below.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
1	19.8	8431	83.6
2	21.2	8512	90.4

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
3	19.4	8554	83.1
4	13.9	8007	55.6
5	13.7	8057	55.0
6	15.2	8017	60.9
7	14.4	7881	56.8

C.4.15.4 Technical Feasibility of Available Controls

As indicated in Section C.3.4, the following determinations were made regarding the technical feasibility of identified control options for the CT at SJBGP:

- SNCR and NSCR are not technically feasible options.
- WSI is not available for Rolls Royce or Solar turbines and thus is not a technically feasible option.
- GCP is a technically feasible option and is currently utilized by Hilcorp based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- DLN is a technically feasible option expected to achieve a vendor-quoted NO_X emission rate of 25 ppm. [126]
- SCR is a technically feasible option expected to achieve an average NO_X control efficiency of 80 percent.[127]
- Unit replacement is a technically feasible option expected, in the case of Units 1, 2 and 3, to achieve a NO_X emission rate of 15 ppm, consistent with the emission standards for new natural gas-fired combustion turbines in 20.2.50 NMAC.[128] In the case of Units 4, 5, 6, and 7, because a DLN retrofit option is available for the make and model of CT comprising the existing units, it is assumed that DLN would be available on equivalent replacements. Therefore, replacement is expected to achieve a NO_X emission rate of 25 ppm, consistent with manufacturer specifications for similar, new CT equipped with DLN.
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, Hilcorp has not indicated that it intends to permanently retire any of the affected units, so this option is not evaluated further.
- Electrification is a technically feasible option for Units 1, 2 and 3 that would result in a 100 percent reduction of NO_X (and all other pollutants). Electrification is not a feasible option for Units 4, 5, 6, and 7 because they are used to generate electricity for the facility.

As indicated in Section C.3.6, the following determinations were made regarding the technical feasibility of identified control options for the ATS at SJBGP:

[126] Hilcorp's 7/14/23 submittal indicated that DLN upgrades for the Rolls Royce Avon turbines (Units 1-3) would not be available until 2025.

[127] Hilcorp assumed a NOX control efficiency of 65-75% in the SCR evaluations provided in its initial FFA. While NMED disagrees with this assumption, NMED notes that in its own evaluation, SCR remains cost effective for Units 2 and 4-7 even if the control efficiency is reduced to 75%.

[128] 20.2.50 NMAC contains varying emission standards for new natural gas-fired stationary combustion turbines based on rated brake horsepower. See Section 113, Table 3. Equivalent replacements for Units 1, 2 and 3 would be subject to the NO_X standard for new CT ≥4,000 and <15,900 bhp (15 ppm).

- A flare is a technically feasible option. However, if used as the primary control device, a flare is inferior to all other forms of disposal because most of the H_2S in the acid gas stream (typically 98% or more) is converted to SO_2 and emitted into the atmosphere. Therefore, NMED did not evaluate this option.
- A SRU is a technically feasible option. However, no facility with an ATS evaluated by NMED currently uses a SRU. Many, and possibly all gas processing plants in New Mexico that previously used a SRU have decommissioned them in recent years due to operational concerns and/or compliance issues, some of which resulted in enforcement actions against the facility due to significant excess SO_2 emissions. NMED supports and encourages the transition away from SRUs towards more effective forms of acid gas disposal, such as AGI wells. In addition, NMED is confident that the cost effectiveness of a SRU would exceed its $10,000/ton cost effectiveness threshold, for the same reason it believes an AGI well would exceed the threshold (see explanation below). Therefore, NMED did not evaluate this option.
- A TO is a technically feasible option and is currently used as the primary control device for the ATS at SJBGP. Therefore, NMED did not evaluate this option.
- The technical feasibility of an AGI well is extremely dependent on the geologic characteristics of the potential well site. Therefore, absent a detailed geologic study, NMED is unable to determine whether an AGI well is technically feasible at SJBGP. However, even assuming an AGI well is technically feasible, NMED believes it has sufficient information to conclude that it would not be cost effective without performing a full FFA. Gas produced from the San Juan Basin in northwest New Mexico is primarily "sweet" gas containing relatively little H_2S. As a result, the primary purpose of the ATS at SJBGP is to remove CO_2 from recovered NGL, although small quantities of H_2S are also removed. Given the small quantities of H_2S removed by the ATS, SO_2 emissions from the TO average just 0.1 tons per year.[129] Hence, the potential emissions reductions from installing an AGI well are extremely limited. Considering that the capital costs for an AGI well, two compressors (primary and backup), and related piping can easily exceed $10 million, NMED is confident, given the potential for less than a ton of emissions reductions, that the cost effectiveness of an AGI well would greatly exceed its $10,000/ton cost effectiveness threshold. Therefore, NMED did not evaluate this option.
- While improved flare design might reduce emissions somewhat during TO SSM/M events, the potential marginal improvement in combustion efficiency – perhaps 1 to 2 percentage points – from the most optimized flare is not anticipated to be a cost-effective option for reducing SO_2 emissions from acid gas flaring during TO SSM/M events. Therefore, NMED did not evaluate this option.

C.4.15.5 Four-Factor Analysis

In order to determine what control measures are necessary at SJBGP to make reasonable progress, NMED conducted a FFA of potential control measures for the NO_X units identified in section C.4.15.2 above. NMED did not conduct a FFA of potential control measures for SO_2 for SJBGP's ATS because alternatives to the existing TO are either inferior, not cost effective, or both. States are required to consider four statutory factors – cost of compliance, time necessary for compliance, energy and non-air

[129] Based on 2016-2022 emission inventory data.

quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[130]

C.4.15.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X emissions reduced, of each technically feasible control option identified in section C.4.15.4 above. NMED utilized source-specific cost estimates provided by Hilcorp in its calculations whenever possible. In cases where Hilcorp failed to provide source-specific cost estimates or NMED found estimates provided by Hilcorp to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[131]

NMED's cost effectiveness values for all technically feasible controls for the NO_X units at SJBGP are summarized below. NMED believes these values were calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed cost effectiveness calculations for the NO_X units at SJBGP and supporting documentation for NMED's cost estimates are provided in Appendix D.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
1	DLN	$831,415	2.4	$351,000
	SCR	$687,435	66.9	$10,000
	Replacement	$4,325,174	34.9	$124,000
2	DLN	$831,415	3.5	$237,000
	SCR	$689,106	72.3	$10,000
	Replacement	$4,325,174	38.3	$113,000
3	DLN	$831,415	-0.2 (1)	-$4,990,000 (1)
	SCR	$688,251	66.5	$10,000
	Replacement	$4,325,174	33.2	$130,000
4	DLN	$349,891	38.1	$9,000
	SCR	$231,225	44.5	$5,000
	Replacement	$1,134,203	38.1	$30,000
5	DLN	$349,891	37.7	$9,000
	SCR	$231,200	44.0	$5,000
	Replacement	$1,134,203	37.7	$30,000
6	DLN	$349,891	43.2	$8,000
	SCR	$232,091	48.7	$5,000

[130] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).

[131] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
	Replacement	$1,134,203	43.2	$26,000
7	DLN	$349,891	40.2	$9,000
	SCR	$231,249	45.5	$5,000
	Replacement	$1,134,203	40.2	$28,000
All Units	Electrification	$15,122,088	485.6	$31,000

(1) Negative estimated reductions and cost effectiveness are an artifact of NMED's methods for calculating these values and do not accurately represent the cost effectiveness of the control or its expected emissions impact. Negative values are an indication that the emission rate associated with the control is greater than the current emission rate of the unit in question, which means the control would not be expected to reduce emissions. Controls that would not reduce emissions are not cost-effective on their face and are excluded from further consideration.

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the NO_X units at SJBGP:

- Hilcorp did not provide a company-specific cost of capital, so the bank prime rate (7.5 percent as of December 2024) was used to determine the appropriate capital recovery factor.
- The Total Capital Costs (TCC), Direct Annual Costs (DAC), and Indirect Annual Costs (OAC) of SCR were calculated using EPA's SCR Tool. An SCR retrofit factor of 1 (average difficulty) was applied, consistent with the SCR evaluations provided in Hilcorp's initial FFA.
- Hilcorp indicated that significant upgrades to the electric utility infrastructure would be needed to support electrification; this assertion was supported by a letter from the City of Farmington Electric Utility System. Hilcorp also provided a detailed cost estimate for the capital costs associated with replacing Units 1-3, which provide compression, with EMD units. NMED's electrification evaluation includes these costs as well as estimated substation and transmission line costs. NMED's evaluation also conservatively assumes that providing line power to electrify Units 1-3 would obviate the need for Units 4-7, which currently provide power for the facility, and that they would be retired if the facility electrified Units 1-3.
- Hilcorp, like most of the companies required to submit a FFA, did not provide information regarding the TCI associated with the replacement of the CT units at SJGP with new, functionally equivalent natural gas-fired units. NMED reviewed several publicly available resources with information that could be used to estimate the TCI of a replacement CT[132] along with information provided by other companies with similar units. NMED determined that the most applicable cost metric ($ per hp basis) was provided by El Paso Natural Gas Company in support of their FFA submittals. NMED understands that the use of this metric is likely accurate to within ±30 percent, but also recognizes that various preliminary vendor quotes are often caveated with a similar degree of accuracy.

C.4.15.5.2 Compliance Time

Hilcorp indicated it would take 2-3 years to implement DLN or SCR on Units 4, 5, 6, and 7. Based on information provided by other facilities and other resources, NMED believes these timeframes are reasonable.

[132] This includes, but is not limited to, the U.S. EPA's Combined Heat and Power Catalog of Technologies (Reciprocating engines) and the U.S. Energy Information Agency's *Cost and Performance Characteristics of New Generating Technologies* in the 2023 Annual Energy Outlook.

Hilcorp did not provide an estimate of the time necessary to implement DLN or SCR on Units 1, 2, and 3. NMED's general assessment of compliance times provided in Section C.3.4 is believed to be reasonably accurate.

Hilcorp also did not provide an estimate of the time necessary to replace the CT at SJBGP. NMED believes the general compliance times for replacement with new, functionally equivalent natural gas-fired CT or EMD provided in Section C.3.4 are reasonable but recognizes that in the case of EMD several more years could be required considering the relative complexity.

C.4.15.5.3 Remaining Useful Life

Despite the age of the units at SJBGP (~40 years), owners and operators of gas compression equipment in New Mexico have indicated that similar CT would last at least 20 more years with proper maintenance. Twenty years is thus the estimated remaining useful life for DLN.

Manufacturers of new CT will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new CT are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement CT is 30 years.

Consistent with generally accepted EPA methodology and NMED's experience, the useful life of SCR is estimated to be 20 years.

There is limited information about the useful life of EMD units, but research suggests the useful life is at least 25 years.

C.4.15.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for CT is provided in Section C.3.4.

C.4.15.5.5 Summary

NMED performed a FFA for all technically feasible control options for NO_X for the units listed in Section C.4.15.2 above. The four statutory factors are discussed in Sections C.4.15.5.1 through C.4.15.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
1	DLN	$351,000	2-3	20	None
	SCR	$10,000	3-4	20	None
	Replacement	$124,000	3-4	30	None
2	DLN	$237,000	2-3	20	None
	SCR	$10,000	3-4	20	None
	Replacement	$113,000	3-4	30	None
3	DLN	-$4,990,000	2-3	20	None
	SCR	$10,000	3-4	20	None

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
	Replacement	$130,000	3-4	30	None
4	DLN	$9,000	2-3	20	None
	SCR	$5,000	2-3	20	None
	Replacement	$30,000	3-4	30	None
5	DLN	$9,000	2-3	20	None
	SCR	$5,000	2-3	20	None
	Replacement	$30,000	3-4	30	None
6	DLN	$8,000	2-3	20	None
	SCR	$5,000	2-3	20	None
	Replacement	$26,000	3-4	30	None
7	DLN	$9,000	2-3	20	None
	SCR	$5,000	2-3	20	None
	Replacement	$28,000	3-4	30	None
All Units	Electrification	$31,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

C.4.15.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[133]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For emissions units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For emissions units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective control is necessary to make reasonable progress. The sole exception to these general rules is the categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

[133] See *supra* note 13.

NMED's FFA identified cost-effective controls for SJBGP Units 1, 2, 3, 4, 5, 6, and 7. Based on its analysis of the four statutory factors and the decision-making criteria described above, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
1	SCR	66.9
2	SCR	72.3
3	SCR	66.5
4	SCR	44.5
5	SCR	44.0
6	SCR	48.7
7	SCR	45.5

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
4	DLN	Less stringent than SCR
5	DLN	Less stringent than SCR
6	DLN	Less stringent than SCR
7	DLN	Less stringent than SCR

As noted above, NMED did not conduct a FFA of potential control measures for SJBGP's ATS. Because the alternatives to the existing TO are either inferior, presumptively not cost effective, or both, NMED determined that reasonable progress does not require new controls for the ATS.

Based on the expected reductions from the controls NMED has determined are necessary to make reasonable progress, NMED estimates the total emissions reductions at SJBGP during the second planning period will be approximately 388.4 ton/yr of NO_X.

C.4.16 IACX Roswell – Bitter Lake Compressor Station

Resources used in NMED's FFA for Bitter Lake Compressor Station (BLCS) include, but are not limited to, the following:

- The FFA completed by Trinity Consultants for IACX Roswell, LLC (IACX) and submitted to NMED on or about 11/1/19.
- Additional information provided by IACX on 1/29/20, 11/4/20 and 1/5/21.
- A detailed discussion between IACX and NMED on 7/7/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA's Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP region (March 23, 2020).
- FFAs developed for similar facilities in New Mexico and other states.

C.4.16.1 Facility Description

BLCS is a natural gas compressor station located 13.3 miles northeast of Roswell in Chaves County, New Mexico at latitude 33° 33' 11", longitude -104° 23' 27". It is owned and operated by IACX and is currently authorized as a synthetic minor source under New Source Review Permit No. 0274-M8. The facility previously operated as a major source under Title V Operating Permit No. P047-R3, which was cancelled at IACX's request on March 13, 2020. The shortest distance to the boundary of the nearest Class I Area, Salt Creek Wilderness Area, is approximately 1.1 miles. Notably, Salt Creek Wilderness Area is the only Class I Area in New Mexico projected to be above the URP glidepath in 2028 and for which a robust demonstration is required.[134]

The function of the facility is to gather casinghead gas from multiple wells and compress the gas using natural gas-fired compressor engines. The facility is authorized for continuous operation, and its total potential to emit is 79.6 tons per year of NO_X and 1.5 tons per year of SO_2.[135]

C.4.16.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at BLCS. No units met NMED's criteria for requiring an evaluation of potential control measures for SO_2.[136]

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
C-891	2SLB RICE	Cooper Bessemer GMVH-10C	4/7/1981	2,250 hp
C-893	2SLB RICE	Cooper Bessemer GMVH-10C	4/7/1981	2,250 hp

C.4.16.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. IACX did not request a future utilization adjustment for BLCS. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the emissions units at BLCS.

NMED calculated baseline actual emissions for the emissions units at BLCS by multiplying representative annual operating hours by the NO_X emission rates reported in IACX's most recent periodic emissions test report(s).[137,] Because the emissions units at BLCS operate at varying loads, NMED conservatively

[134] See Chapter 10, Progress, Degradation, and URP Glidepath Checks for Class I Areas in New Mexico, for NMED's robust demonstration for Salt Creek Wilderness Area.

[135] AQB New Source Review Permit No. 0274-M8, Table 102.A.

[136] See Chapter 6, Selection of Sources for Control Measures Analysis, for a detailed discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.

[137] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.

adjusted reported emission rates to 100 percent load to represent worst-case emissions.[138] Reported and adjusted emission rates for the emissions units at BLCS are summarized below.

Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr @ 100% load)
C-891	11/15/22	2.22	42%	5.2
C-893	NA (1)	---	---	5.2 (2)

(1) NA = Not Available

(2) The average adjusted emissions of identical Unit C-891 were used as a surrogate for Unit C-893, as NMED was unable to locate a recent emissions test report for this unit.

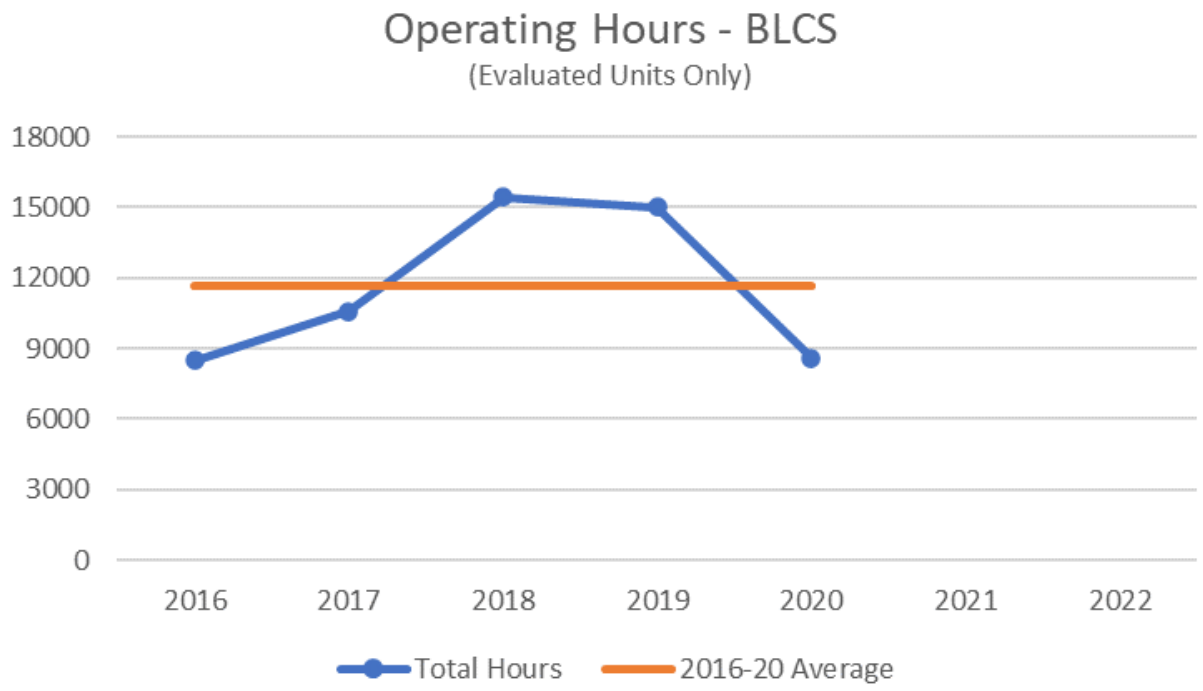
At IACX's request, NMED cancelled the Title V operating permit for BLCS on March 13, 2020, after IACX re-permitted the facility under a general construction permit for oil and gas facilities.[139] As a result, IACX is no longer required to submit an annual emission inventory, which includes operating hours. 2020 was the last year IACX submitted such an inventory to NMED.[140] Therefore, to determine representative annual operating hours for the emissions units at BLCS, NMED analyzed 2016-2020 operating hours reported by IACX pursuant to 20.2.73 NMAC. 2016-2020 operating hours for the emissions units at BLCS are summarized and plotted below.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours
C-891	6638	8571	7530	7601	1042
C-893	1851	1998	7922	7411	7557

[138] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.

[139] IACX subsequently re-permitted BLCS again under a New Source Review permit due to the facility being located within three miles of a Class I Area and thus ineligible for a general construction permit for oil and gas facilities.

[140] Only major sources are required to submit emissions inventories annually. Minor sources are only required to do so every three years. 2020 was the last triennial inventory year for New Mexico.



As shown above, BLCS' year-over-year operating hours have risen and fallen in recent years, with no obvious pattern and no discernible impact from the pandemic in 2020. Therefore, NMED determined that 2016-2020 average operating hours are representative for the emissions units at BLCS.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the emissions units at BLCS are summarized below.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
C-891	5.2	6276	16.4
C-893	5.2	5348	14.0

C.4.16.4 Technical Feasibility of Available Controls

As indicated in Section C.3.1, the following determinations were made regarding the technical feasibility of identified control options for the 2SLB RICE at BLCS:

- SCR, SNCR, and NSCR are not technically feasible options.
- GCP is a technically feasible option and is currently utilized by IACX based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- Units C-891 and C-893 are already equipped with LEC. However, IACX indicated that some LEC upgrades are technically feasible for these units. These upgrades are expected to achieve a vendor-quoted NO_X emission rate of 2.0 g/hp-hr.

- Unit replacement is a technically feasible option expected to achieve a NO_X emission rate of 0.3 g/hp-hr, consistent with the emission standards for new natural gas-fired spark ignition engines in 20.2.50 NMAC.[141].
- Unit retirement is a technically feasible option and would result in a 100 percent reduction of NO_X (and all other pollutants). However, IACX has not indicated that it intends to permanently retire any of the affected units, so this option is not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants).

C.4.16.5 Four-Factor Analysis

In order to determine what control measures are necessary at BLCS to make reasonable progress, NMED conducted a FFA of potential control measures for NO_X for the emissions units identified in section C.4.16.2 above. States are required to consider four statutory factors – cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[142]

C.4.16.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X emissions reduced, of each technically feasible control option identified in section C.4.16.4 above. NMED utilized source-specific cost estimates provided by IACX in its calculations whenever possible. In cases where IACX failed to provide source-specific cost estimates or NMED found estimates provided by IACX to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[143]

NMED's cost effectiveness values for all technically feasible controls for the emissions units at BLCS are summarized below. NMED believes these values were calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed cost effectiveness calculations for the emissions units at BLCS and supporting documentation for NMED's cost estimates are provided in Appendix D.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
C-891	LEC	$129,808	-14.9 (1)	-$9,000 (1)
	Replacement	$823,801	11.7	$70,000

[141] 20.2.50 NMAC contains varying emission standards for new natural gas-fired spark ignition engines based on engine type and rated brake horsepower. See Section 113, Table 2. Equivalent replacements for the 2SLB RICE at BLCS would be subject to the NO_X standard for new lean burn engines ≥1,875 bhp (0.3 g/bhp-hr).
[142] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).
[143] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
C-893	LEC	$129,808	-12.7 (1)	-$10,000 (1)
	Replacement	$823,801	10.0	$82,000
All Units	Electrification	$1,408,011	30.4	$46,000

(1) Negative estimated reductions and cost effectiveness are an artifact of NMED's methods for calculating these values and do not accurately represent the cost effectiveness of the control or its expected emissions impact. Negative values are an indication that the emission rate associated with the control is greater than the current emission rate of the unit in question, which means the control would not be expected to reduce emissions. Controls that would not reduce emissions are not cost-effective on their face and are excluded from further consideration.

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the emissions units at BLCS:

- IACX did not provide a company-specific cost of capital, so the bank prime rate (7.5 percent as of December 2024) was used to determine the appropriate capital recovery factor.
- IACX, like most of the companies required to submit a FFA, did not provide information regarding the Total Capital Investment (TCI) associated with the replacement of the 2SLB RICE units at BLCS with new, functionally equivalent natural gas-fired units. NMED reviewed several publicly available resources with information that could be used to estimate the TCI of a replacement RICE[144] along with information provided by other companies with similar units. NMED determined that the most applicable cost metric ($ per hp basis) was provided by El Paso Natural Gas Company in support of their FFA submittals. NMED understands that the use of this metric is likely accurate to within ±30 percent, but also recognizes that various preliminary vendor quotes are often caveated with a similar degree of accuracy.
- IACX did not provide information regarding the costs associated with electrification. Therefore, NMED applied a Total Capital Cost (TCC) metric of $2,084/hp (2023$), which it developed using detailed cost information provided by other facilities, to calculate TCC. The TCI calculated by NMED assumes no costs associated with substation or utility line upgrades because of lack of information. NMED understands that this assumption likely underestimates costs given that IACX indicated utility infrastructure upgrades would be needed to support electrification at BLCS.

C.4.16.5.2 Compliance Time

IACX indicated it would take 2 years to implement LEC upgrades on the 2SLB RICE units at BLCS. Based on information provided by other facilities and other resources, NMED believes this timeframe is reasonable.

IACX did not provide an estimate of the time necessary to replace the 2SLB RICE units at BLCS. NMED believes the general compliance times for replacement with like-kind natural gas-fired engines or EMD provided in Section C.3.1 are reasonable but recognizes that in the case of EMD several more years could be required considering the relative complexity.

[144] This includes, but is not limited to, the U.S. EPA's Combined Heat and Power Catalog of Technologies (Reciprocating engines) and the U.S. Energy Information Agency's *Cost and Performance Characteristics of New Generating Technologies* in the 2023 Annual Energy Outlook.

C.4.16.5.3 Remaining Useful Life

Despite the age of the 2SLB RICE at BLCS (~40 years), owners and operators of gas compression equipment in New Mexico have indicated that similar RICE would last at least 20 more years with proper maintenance. Twenty years is thus the estimated remaining useful life for LEC.

Manufacturers of new RICE will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new RICE are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement RICE is 30 years.

There is limited information about the useful life of EMD units, but research suggests the useful life is at least 25 years.

C.4.16.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for 2SLB RICE is provided in Section C.3.1.

C.4.16.5.5 Summary

NMED performed a FFA for all technically feasible control options for NO_X for the units listed in Section C.4.16.2 above. The four statutory factors are discussed in Sections C.4.16.5.1 through C.4.16.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
C-891	LEC	-$9,000	2	20	None
	Replacement	$70,000	3-4	30	None
C-893	LEC	-$10,000	2	20	None
	Replacement	$82,000	3-4	30	None
All Units	Electrification	$46,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

C.4.16.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze

Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[145]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For emissions units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For emissions units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective control is necessary to make reasonable progress. The sole exception to these general rules is the categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

NMED's FFA did not identify any cost-effective controls for BLCS Units C-891 or C-893. Therefore, NMED determined that reasonable progress does not require new controls on either of these units.

C.4.17 Oxy USA WTP Limited Partnership – Indian Basin Gas Plant

Resources used in NMED's FFA for Indian Basin Gas Plant (IBGP) include, but are not limited to, the following:

- The FFA completed by Trinity Consultants for Oxy USA WTP Limited Partnership (Oxy) and submitted to NMED on 10/31/19.
- Additional information provided by Oxy on 2/13/20, 10/21/20, 7/21/23, and 8/14/23.
- Detailed discussions between Oxy and NMED on 7/6/23 and 4/24/24.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA's Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP Region (March 23, 2020).
- FFAs developed for similar facilities in New Mexico and other states.

C.4.17.1 Facility Description

IBGP is a natural gas processing facility located 14.5 miles west of Carlsbad in Eddy County, New Mexico at latitude 32° 27' 50", longitude -104° 34' 27". It is owned and operated by Oxy and currently operates under Title V Operating Permit No. P103-R3, which expires on November 1, 2024.[146] The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 21.2 miles.

[145] See *supra* note 13.

[146] Oxy submitted a timely application to renew Title V Operating Permit No. P103-R3 on October 12, 2023. At the time of preparation of this technical support document, NMED had not taken final action on the application.

The function of the facility is to remove hydrogen sulfide, carbon dioxide, condensate and water from raw natural gas to make commercial natural gas. The facility also extracts natural gas products (propane and butane) from natural gas. The facility is authorized for continuous operation, and its total potential to emit is 363.0 tons per year of NO_X and 87.1 tons per year of SO_2.[147]

C.4.17.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at IBGP:[148]

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
ES-06/07	Turbine	Solar Centaur 40	1980	4,000 hp
ES-08/09	Turbine	Solar Centaur 40	1980	4,000 hp
ES-10/11	Turbine	Solar Centaur 40	1980	4,700 hp

NMED also elected to evaluate the ATS at IBGP for potential control measures for SO_2 due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). The ATS at IBGP consists of an ATU (Unit AU-01), AGI well (Unit AGI), electric AGI well compressor (Unit AG-COM), and an acid gas flare (Unit ES-50). During normal operations, acid gas exiting the ATUs is routed to the AGI well for disposal resulting in no emissions to the atmosphere. During AGI SSM/M events, acid gas is rerouted to the acid gas flare for disposal, which produces SO_2 emissions.

C.4.17.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. Oxy did not request a future utilization adjustment for IBGP. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the emissions units at IBGP.

For the emissions units at IBGP requiring a FFA of potential control measures for NO_X ("NO_X units"), NMED calculated baseline actual emissions by multiplying representative annual operating hours by the NO_X emission rates reported in Oxy's most recent periodic emissions test report(s).[149,] Because the NO_X units at IBGP operate at varying loads, NMED conservatively adjusted reported emission rates to 100 percent load to represent worst-case emissions.[150] Reported and adjusted emission rates for the NO_X units at IBGP are summarized below.

[147] AQB Title V Operating Permit No. P103-R3, Table 102.A.

[148] See Chapter 6, Selection of Sources for Control Measures Analysis, for a detailed discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.

[149] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.

[150] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.

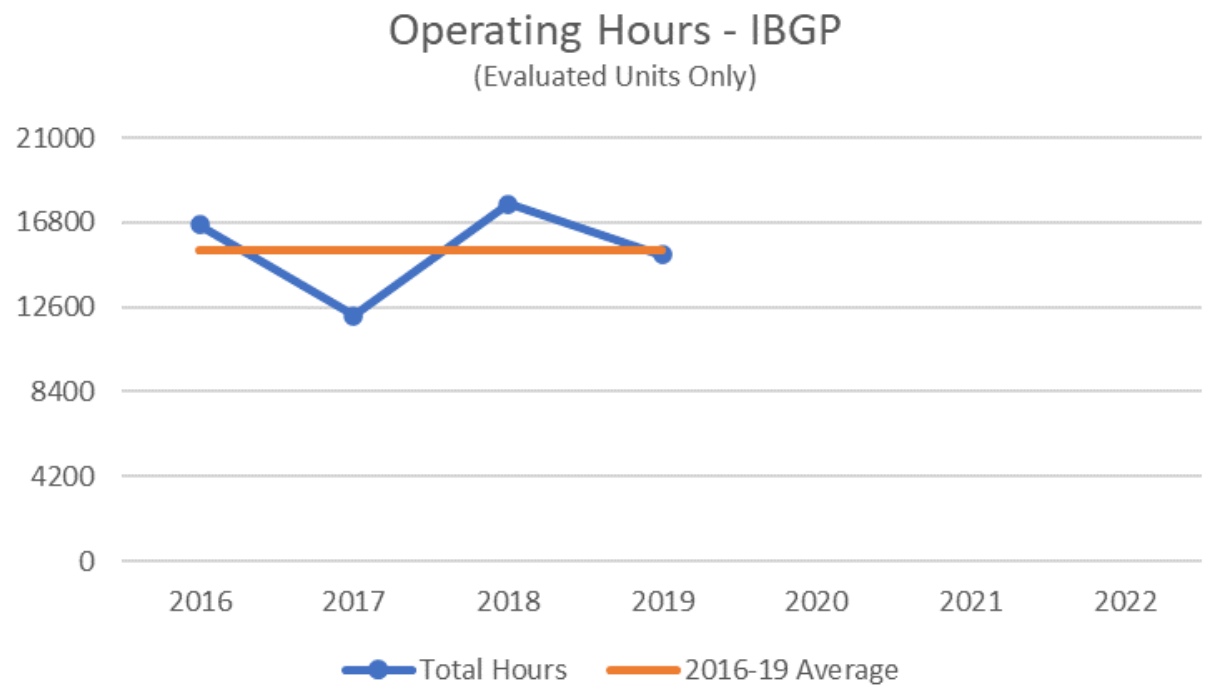
Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr @ 100% load)
ES-06/07	2/12/19	14.8	100%	14.8
ES-08/09	NA [1]	---	---	15.4 [2]
ES-10/11	2/12/19	9.8	99%	9.9

[1] NA = Not Available

[2] The average adjusted emissions of identical Unit ES-06/07 were used as a surrogate for Unit ES-08/09, as NMED was unable to locate a recent emissions test report for this unit.

To determine representative annual operating hours for the NO_X units at IBGP, NMED analyzed 2016-2019 operating hours reported by Oxy pursuant to 20.2.73 NMAC (the facility has been idled since June 2020, and 2019 was its last full year of operation). 2016-2019 operating hours for the NO_X units at IBGP are summarized and plotted below.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours
ES-06/07	8664	6051	7340	4651
ES-08/09	8014	6135	6604	4853
ES-10/11	0	0	3772	5685



As shown above, year-over-year operating hours for the NO_X units at IBGP varied somewhat randomly with no discernable trend during the period 2016-2019. Therefore, NMED determined that 2016-2019 average operating hours are representative for Units ES-06/07 and ES-08/09. Unit ES-10/11 did not operate in 2016 or 2017, and NMED did not think 2018-2019 operating hours were necessarily representative of future operations due to the limited sample size. Furthermore, in a detailed discussion between Oxy and NMED on 4/24/24, Oxy suggested that utilization could increase if the plant is ever

restarted. Therefore, NMED determined that 8,760 hours is representative for Unit ES-10/11, consistent with what Oxy assumed in its initial FFA submittal.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the NO_X units at IBGP are summarized below.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
ES-06/07	14.8	6677	49.3
ES-08/09	14.8	6402	47.3
ES-10/11	9.9	8760	43.4

NMED estimated baseline actual SO_2 emissions for the ATS at IBGP by averaging 2016-2019 emissions reported by Oxy pursuant to 20.2.73 NMAC. These emissions are summarized below.

Unit No.	2016 Emissions (tons)	2017 Emissions (tons)	2018 Emissions (tons)	2019 Emissions (tons)	Average Emissions (ton/yr)
ES-50	8.2	7.4	8.1	5.9	24.6
ES-50 SSM	41.9	8.0	17.6	1.2	

C.4.17.4 Technical Feasibility of Available Controls

As indicated in Section C.3.4, the following determinations were made regarding the technical feasibility of identified control options for the CT at IBGP:

- WSI, SNCR, and NSCR are not technically feasible options.
- GCP is a technically feasible option and is currently utilized by Oxy based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- DLN is a technically feasible option expected to achieve a vendor-quoted NO_X emission rate of 25 ppm.
- SCR is a technically feasible option expected to achieve an average NO_X control efficiency of 80 percent.
- Unit replacement is a technically feasible option expected to achieve a NO_X emission rate of 15 ppm, consistent with the emission standards for new natural gas-fired combustion turbines in 20.2.50 NMAC.[151]
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, Oxy did not indicate that it intends to permanently retire any of the affected units, so this option is not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants).

[151] 20.2.50 NMAC contains varying emission standards for new natural gas-fired stationary combustion turbines based on rated brake horsepower. See Section 113, Table 3. Equivalent replacements for the CT at IBGP would be subject to the NO_X standard for new CT ≥4,000 and <15,900 bhp (15 ppm).

As indicated in Section C.3.6, the following determinations were made regarding the technical feasibility of identified control options for the ATS at IBGP:

- A flare, SRU or TO are technically feasible options. However, compared to an AGI well, which is currently used as the primary control device for the ATS at IBGP, a flare, SRU or TO is an inferior control. An ATS with a flare, SRU or TO will produce SO_2 emissions during normal operations and during SSM/M events. Conversely, an ATS with an AGI well will produce SO_2 emissions only during AGI SSM/M events. Therefore, NMED did not evaluate these options.
- While improved flare design might reduce emissions somewhat during AGI SSM/M events, the potential marginal improvement in combustion efficiency – perhaps 1 to 2 percentage points – from the most optimized flare is not anticipated to be a cost-effective option for reducing SO_2 emissions from acid gas flaring during AGI SSM/M events. Therefore, NMED did not evaluate this option.
- Adding backup, redundant compression to the ATS is a technically feasible option for reducing SO_2 emissions from acid gas flaring during AGI SSM/M events.

C.4.17.5 Four-Factor Analysis

In order to determine what control measures are necessary at IBGP to make reasonable progress, NMED conducted a FFA of potential control measures for NO_X for the NO_X units identified in section C.4.17.2 above. NMED also conducted a FFA of the only technically feasible control option for the ATS, i.e., adding redundant compression to reduce AGI SSM/M flaring emissions. States are required to consider four statutory factors – cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[152]

C.4.17.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X or SO_2 emissions reduced, of each technically feasible control option identified in section C.4.17.4 above. NMED utilized source-specific cost estimates provided by Oxy in its calculations whenever possible. In cases where Oxy failed to provide source-specific cost estimates or NMED found estimates provided by Oxy to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[153]

NMED's cost effectiveness values for all technically feasible controls for the emissions units at IBGP are summarized below. NMED believes these values were calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed calculations and supporting documentation for NMED's cost estimates are provided in Appendix D.

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[152] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).

[153] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
ES-06/07	DLN	$313,173	36.5	$9,000
	SCR	$458,400	39.5	$12,000
	Replacement	$1,137,517	41.6	$27,000
ES-08/09	DLN	$313,173	35.0	$9,000
	SCR	$457,457	37.8	$12,000
	Replacement	$1,137,517	39.9	$28,000
ES-10/11	DLN	$289,862	29.0	$10,000
	SCR	$462,198	34.8	$13,000
	Replacement	$1,333,590	34.8	$38,000
All CT	Electrification	$4,394,819	140.1	$31,000
ATS	Redundant Compression	$562,019	22.1	$25,000

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the emissions units at IBGP:

- Oxy did not provide a company-specific cost of capital, so the bank prime rate (7.5 percent as of December 2024) was used to determine the appropriate capital recovery factor.
- The Total Capital Costs (TCC), Direct Annual Costs (DAC), and Indirect Annual Costs (OAC) of SCR were calculated using EPA's SCR Tool. An SCR retrofit factor of 1 (average difficulty) was applied, due to a lack of information from Oxy supporting a higher retrofit factor. Oxy indicated that there is insufficient power available to support SCR but did not provide a cost estimate for necessary utility infrastructure upgrades. As a result, NMED included $5M for these upgrades in its cost estimate. NMED believes this value likely underestimates the cost based on information provided by other facilities.
- Oxy, like most of the companies required to submit a FFA, did not provide information regarding the TCI associated with the replacement of their CT units with new, functionally equivalent natural gas-fired units. NMED reviewed several publicly available resources with information that could be used to estimate the TCI of a replacement CT[154] along with information provided by other companies with similar units. NMED determined that the most applicable cost metric ($ per hp basis) was provided by El Paso Natural Gas Company in support of their FFA submittals. NMED understands that the use of this metric is likely accurate to within ±30 percent, but also recognizes that various preliminary vendor quotes are often caveated with a similar degree of accuracy.
- Oxy did not provide information regarding the costs associated with electrification. Therefore, NMED applied a Total Capital Cost (TCC) metric of $2,084/hp (2023$), which it developed using detailed cost information provided by other facilities, to calculate TCC. NMED also included $5M for utility infrastructure upgrades based on Oxy's assertion that there is insufficient power to support SCR. NMED believes this value likely underestimates the cost based on information provided by other facilities.

[154] This includes, but is not limited to, the U.S. EPA's Combined Heat and Power Catalog of Technologies (Reciprocating engines) and the U.S. Energy Information Agency's *Cost and Performance Characteristics of New Generating Technologies* in the 2023 Annual Energy Outlook.

- Cost estimates for adding redundant compression provided by other natural gas processing facilities in New Mexico ranged from approximately $4.1M to $9.1M (2023$), significantly less than Oxy's undocumented estimate of $14.5M (2023$). Therefore, NMED disregarded Oxy's estimate. NMED did not have sufficient information to determine which of the available estimates from other facilities best represents the cost of adding redundant compression at IBGP, so NMED conservatively used the lowest estimate in its calculations.

C.4.17.5.2 Compliance Time

Oxy indicated it would take 4-5 years to implement DLN on the CT at IBGP. NMED disagrees with this estimate based on information provided by other facilities and believes the general compliance time provided in Section C.3.4 is more reasonable.

Oxy did not provide an estimate of the time necessary to implement SCR. NMED believes the general compliance time provided in Section C.3.4 is reasonable.

Oxy did not provide an estimate of the time necessary to replace the units at IBGP. NMED believes the general compliance times for replacement with like-kind natural gas-fired CT or EMD provided in Section C.3.4 are reasonable but recognizes that in the case of EMD several more years could be required considering the relative complexity.

Oxy indicated it would take approximately 5 years to implement redundant compression on the ATS at IBGP. Based on several recently completed projects, NMED believes a more reasonable compliance time for adding redundant compression is 2-3 years. This does not account for any facility-specific challenges that would prolong implementation.

C.4.17.5.3 Remaining Useful Life

Oxy indicated that the expected useful life of DLN is 20 years. This is consistent with information provided by similar facilities and FFAs completed in other states.

Consistent with generally accepted EPA methodology and NMED's experience, the useful life of SCR is estimated to be 20 years.

Manufacturers of new CT will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new CT are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement CT is 30 years.

There is limited information about the useful life of electric compression equipment, but research suggests the useful life is at least 25 years. For EMD used in acid gas service (i.e., AGI well compressors), NMED believes the useful life would not be longer than 20 years.

C.4.17.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for CT is provided in Section C.3.4.

NMED anticipates no energy or non-air quality impacts from adding redundant compression to the ATS at IBGP.

C.4.17.5.5 Summary

NMED performed a FFA for all technically feasible control options for the emissions units listed in Section C.4.17.2 above. The four statutory factors are discussed in Sections C.4.17.5.1 through C.4.17.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
ES-06/07	DLN	$9,000	2-3	20	None
	SCR	$12,000	3-4	20	None
	Replacement	$27,000	3-4	30	None
ES-08/09	DLN	$9,000	2-3	20	None
	SCR	$12,000	3-4	20	None
	Replacement	$28,000	3-4	30	None
ES-10/11	DLN	$10,000	2-3	20	None
	SCR	$13,000	3-4	20	None
	Replacement	$38,000	3-4	30	None
All CT	Electrification	$31,000	4-6	25	None
ATS	Redundant Compression	$25,000	2-3	20	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

C.4.17.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[155]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For NO_X units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For NO_X units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective control is necessary to make reasonable progress. The sole exception to these general rules is the

[155] See *supra* note 13.

categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

NMED's FFA identified cost-effective controls for IBGP Units ES-06/07, ES-08/09 and ES-10/11. Based on its analysis of the four statutory factors and the decision-making criteria described above, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
ES-06/07	DLN	36.5
ES-08/09	DLN	35.0
ES-10/11	DLN	29.0

NMED's FFA did not identify any cost-effective controls for the ATS at IBGP. Therefore, NMED determined that reasonable progress does not require new controls for the ATS.

Based on the expected reductions from the controls NMED has determined are necessary to make reasonable progress, NMED estimates the total emissions reductions at IBGP during the second planning period will be approximately 100.5 ton/yr of NO_X.

C.4.18 Public Service Company of New Mexico – San Juan Generating Station

San Juan Generating Station (SJGS) is a former 1,800 MW coal-fired electric power plant located 3 miles north of Waterflow in San Juan County, New Mexico at latitude 36° 48' 07", longitude -108° 26' 20". It is owned by Public Service Company of New Mexico (PNM),[156] and was one of 23 facilities selected for an analysis of potential control measures when NMED performed the source screening described in Section C.2 in 2019. However, PNM subsequently shut down SJGS on or about November 1, 2022, and submitted an administrative permit revision closing NSR Permit No. 0063-M12R3 and voluntarily discontinuing Title V Operating Permit No. P062-R4M1 on December 27, 2022. PNM's demolition and remediation plan for the facility was approved by the San Juan County Commission on March 7, 2023, and demolition was initiated on July 10, 2023. The plant's stacks are scheduled to be demolished in the second quarter of 2024, and the majority of the remaining work is expected to be completed by the end of 2025.

NMED originally selected SJGS' two coal-fired boilers (Units S301/E301 and S304/E304) for an analysis of potential control measures for NO_X and SO_2 in the second planning period. However, because SJGS has since been shut down and demolition is underway, NMED did not perform a FFA of potential control measures for these units. EPA guidance provides that a state may forgo a full FFA if a source is already "effectively controlled" and the state can demonstrate why a FFA would not result in new controls and would therefore be a futile exercise.[157] NMED considers it self-evident that a FFA of potential control measures for retired units at a facility that has been shut down and is in the process of being demolished would be futile. There is no more effective control than retirement, which reduces emissions by 100

[156] PNM shared ownership of SJGS' four coal-fired units with the City of Anaheim, California; City of Farmington, New Mexico; Los Alamos County, New Mexico; M-S-R Public Power Authority; Southern California Public Power Authority; Tri-State Generation and Transmission Association, Inc.; Tucson Electric Power Company; and Utah Associated Municipal Power Systems.

[157] EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021) at 5.

percent, and the demolition of SJGS will make it impossible to add new controls. Therefore, NMED has determined that Units S301/E301 and S304/E304 are effectively controlled by virtue of their retirement due to the shutdown of SJGS, and that a FFA could only result in the conclusion that no further controls are necessary to make reasonable progress.

Based on when SJGS was shut down, the emissions reductions resulting from the retirement of the affected units were realized during the second planning period. Therefore, NMED estimated the NO_X and SO_2 emissions reductions resulting from the retirement of Units S301/E301 and S304/E304 by averaging 2016-2021 emissions reported by PNM pursuant to 20.2.73 NMAC. These emissions are summarized below.

Pollutant	2016 Emissions (tons)	2017 Emissions (tons)	2018 Emissions (tons)	2019 Emissions (tons)	2020 Emissions (tons)	2021 Emissions (tons)	Average Emissions (ton/yr)
NO_X	7,165.4	7,594.2	6,403.0	6,478.0	6,772.5	6,629.3	7,007.4
SO_2	1,722.5	1,799.8	1,246.6	1,453.3	1,355.2	936.3	1,558.5

C.4.19 Targa Midstream Services – Eunice Gas Processing Plant

Resources used in NMED's FFA for Eunice Gas Processing Plant (EGPP) include, but are not limited to, the following:

- The FFA completed by Trinity Consultants for Targa Midstream Services, LLC (Targa) and submitted to NMED on or about 11/1/19.
- Additional information provided by Targa on 12/13/19, 2/17/20, 3/12/20, 11/20/20, 2/16/21, 8/4/23, and 3/14/24.
- A detailed discussion between Targa and NMED on 6/8/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP region (March 23, 2020)
- FFAs developed for similar facilities in New Mexico and other states.

C.4.19.1 Facility Description

EGPP is a natural gas processing facility located one mile southeast of Eunice in Lea County, New Mexico at latitude 32° 25' 28", longitude -103° 08' 50". It is owned by Versado Gas Processors, LLC and operated by Targa, and currently operates under Title V Operating Permit No. P109-R3M1, which expires on

November 29, 2024.[158] The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 73.5 miles.

The function of the facility is to receive field natural gas, perform dehydration and removal of carbon dioxide and hydrogen sulfide, and separate natural gas liquids. The facility is authorized for continuous operation, and its total potential to emit is 2606.0 tons per year of NO_X and 482.0 tons per year of SO_2.[159]

C.4.19.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at EGPP:[160]

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
B-01	Boiler	Wickes Type A	<1972	100 MMBTU/hr
B-02	Boiler	Wickes Type A	<1972	100 MMBTU/hr
C-01	2SLB RICE	Clark BA-6	<1972	1,200 hp
C-02	2SLB RICE	Clark BA-6	<1972	1,200 hp
C-03	2SLB RICE	Clark BA-6	<1972	1,200 hp
C-04	2SLB RICE	Clark BA-6	<1972	1,200 hp
C-05	2SLB RICE	Clark BA-6	<1972	1,200 hp
C-06	2SLB RICE	Clark BA-6	<1972	1,200 hp
C-07	2SLB RICE	Clark BA-6	<1972	1,200 hp
C-08 (1)	2SLB RICE	Clark BA-6	<1972	1,200 hp
C-09 (1)	2SLB RICE	Clark BA-6	<1972	1,200 hp
C-10 (1)	2SLB RICE	Clark HBA-8	<1972	1,600 hp
C-11 (1)	2SLB RICE	Clark HBA-8	<1972	1,600 hp
C-12 (1)	2SLB RICE	Clark HBA-8	<1972	1,600 hp
C-13 (1)	2SLB RICE	Clark HBA-T-8	<1972	2,050 hp

(1) Targa's November 2019 FFA indicated that Unit C-08 was inoperable and had been permanently shut down, and its 8/4/23 submittal indicated that Units C-09, C-10, C-11, C-12, and C-13 had also been permanently shut down. Targa has since removed these units from EGPP's NSR and Title V permits. Therefore, NMED did not evaluate them.

NMED also elected to evaluate the ATS at EGPP for potential control measures for SO_2 due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). The ATS at EGPP consists of an ATU (Unit AM-01), AGI well (Unit AGI), two electric AGI well compressors (Units AGI-C1 and AGI-C2), and an acid gas flare (Unit F-01). During normal operations, acid gas exiting the ATU is routed to the AGI well for disposal resulting in no emissions to the atmosphere. During AGI SSM/M events, acid gas is rerouted to the acid gas flare for disposal, which produces SO_2 emissions. AGI SSM/M flaring emissions are minimized via the second, redundant AGI well compressor, which provides compression when the

[158] Targa submitted a timely application to renew Title V Operating Permit No. P109-R3M1 on November 28, 2023. At the time of preparation of this technical support document, NMED had not taken final action on the application.
[159] AQB Title V Operating Permit No. P109-R3M1, Table 102.A.
[160] See Chapter 6, Selection of Sources for Control Measures Analysis, for a detailed discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.

primary AGI well compressor fails or is taken out of service for maintenance, allowing for continued use of the AGI well when flaring would otherwise be required.

C.4.19.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. Targa did not request a future utilization adjustment for EGPP. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the emissions units at EGPP.[161]

For the emissions units at EGPP requiring a FFA of potential control measures for NO_X ("NO_X units"), NMED calculated baseline actual emissions by multiplying representative annual operating hours by the NO_X emission rates reported in Targa's most recent periodic emissions test report(s).[162,] Because the engines at EGPP operate at varying loads, NMED conservatively adjusted reported emission rates to 100 percent load to represent worst-case emissions.[163] Reported and adjusted emission rates for the NO_X units at EGPP are summarized below.

Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr @ 100% load)
B-01	NA [(1)]	---	---	6.0 [(2)]
B-02	NA [(1)]	---	---	6.0 [(2)]
C-01	7/18/23	52.8	96%	55.0
C-02	NA [(1)]	---	---	50.0 [(3)]
C-03	7/18/23	44.2	96%	46.1
C-04	7/18/23	50.1	96%	52.1
C-05	7/18/23	49.7	96%	51.8
C-06	7/18/23	43.0	96%	44.7
C-07	NA [(1)]	---	---	50.0 [(3)]

[(1)] NA = Not Available

[(2)] EGPP's Title V operating permit does not require periodic testing of Units B-01 and B-02. NMED estimated the emissions of these units based on their heat input capacity (MMBtu/hr) and an emission rate (lb/MMBtu) provided by a vendor.

[(3)] The average adjusted emissions of Units C-01, C-03, C-04, C-05, and C-06 were used as a surrogate for Units C-02 and C-07, as NMED was unable to locate a recent emissions test report for these units.

To determine representative annual operating hours for the NO_X units at EGPP, NMED analyzed 2016-2021 operating hours reported by Targa pursuant to 20.2.73 NMAC. NMED was in receipt of Targa's reported 2022 operating hours at the time of its analysis, but the data were still undergoing internal QA/QC checks and had not been certified yet, so NMED excluded them from its analysis. 2016-2021

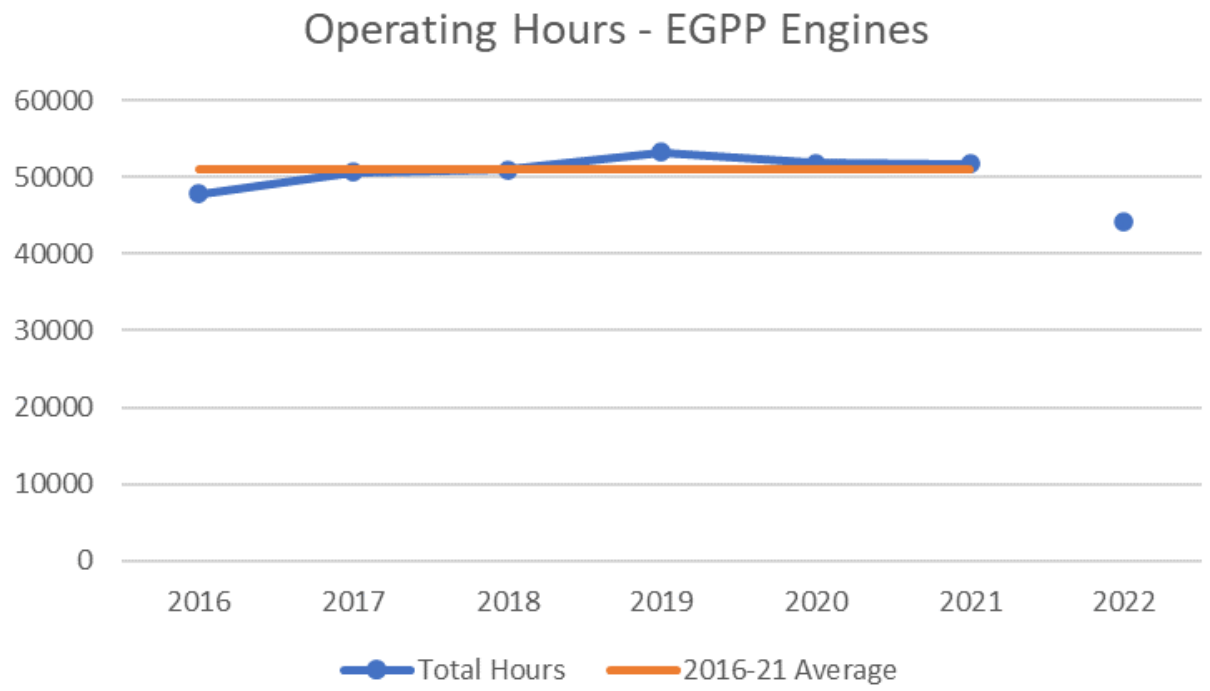
[161] Projected actual emissions for Units C-09, C-10, C-11, C-12, and C-13 are zero. However, NMED still calculated baseline actual emissions for these units for purposes of estimating the NOx emissions reductions resulting from their retirement.

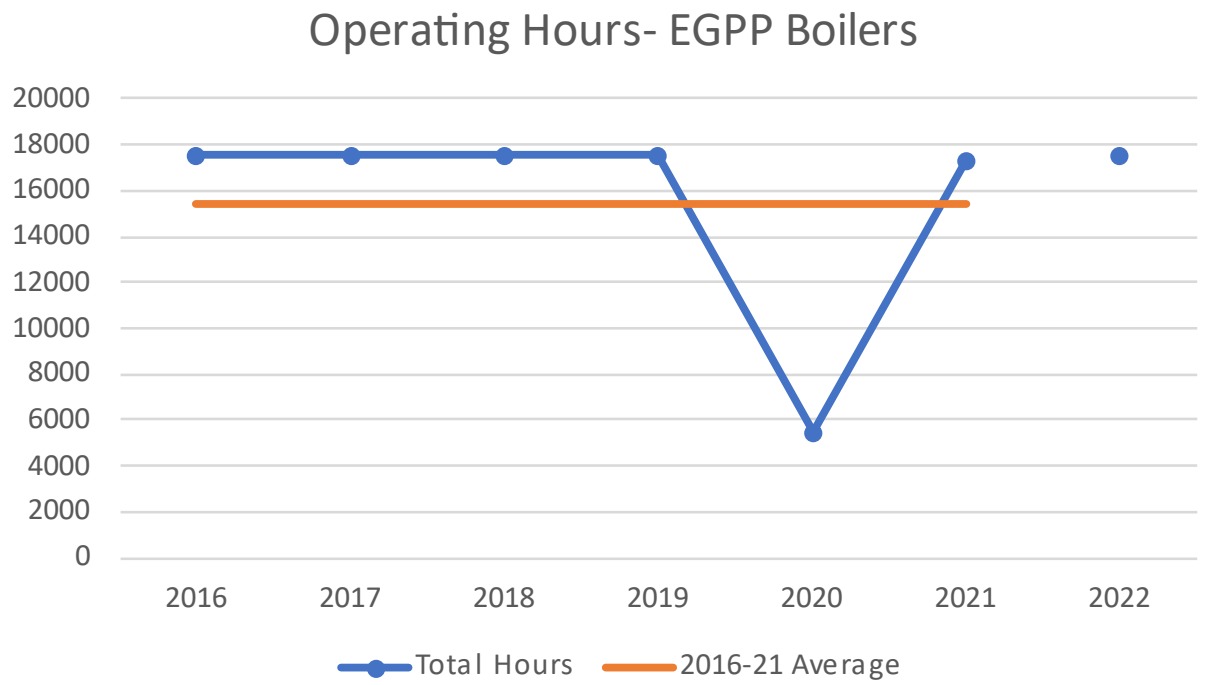
[162] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.

[163] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.

operating hours for the NO_X units at EGPP are summarized and plotted below; reported 2022 operating hours are included for informational purposes only.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
B-01	8760	8760	8760	8760	2738	8642	8760
B-02	8760	8760	8760	8760	2738	8657	8760
C-01	8009	6882	7276	7652	7168	6537	6314
C-02	4271	7840	7580	8368	6537	6306	7725
C-03	7275	6742	6798	7176	8016	7538	7345
C-04	5996	7604	7237	6927	8021	7971	5392
C-05	7684	7168	7931	7499	8107	8010	5900
C-06	8123	6656	6133	7572	7078	7956	5926
C-07	6476	7690	7961	8029	6880	7386	5480





As shown above, year-over-year operating hours for EGPP's engines have been very consistent in recent years, and there was no discernible impact from the pandemic in 2020. Therefore, NMED determined that 2016-2021 average operating hours are representative for these units.[164] Year-over-year operating hours for EGPP's boilers have also been very consistent in recent years. With the exception of 2020, which was an anomaly for unknown reasons,[165] both boilers have consistently seen full time (or nearly full time) utilization. Therefore, NMED determined that 8,760 hr/yr is representative for these units.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the NO_X units at EGPP are summarized below.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
B-01	6.0	8760	26.1
B-02	6.0	8760	26.1
C-01	55.0	7254	199.3
C-02	50.0	6817	170.3
C-03	46.1	7258	167.2
C-04	52.1	7293	190.2
C-05	51.8	7733	200.3

[164] Retired Units C-09, C-10, C-11, and C-12 were standby units limited to operating 500 hr/yr. Therefore, NMED determined that 500 hr/yr is representative for these units. NMED determined that 2016-2019 average operating hours are representative for retired Unit C-13, since 2019 was the last year of operation for this unit.

[165] The lack of a similar drop in operating hours for EGPP's engines in 2020 suggests that the pandemic may not be the cause of that year's boiler utilization anomaly.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
C-06	44.7	7253	162.3
C-07	50.0	7404	184.9

C.4.19.4 Technical Feasibility of Available Controls

As indicated in Section C.3.1, the following determinations were made regarding the technical feasibility of identified control options for the 2SLB RICE at EGPP:

- SCR, SNCR, and NSCR are not technically feasible options.
- GCP is a technically feasible option and is currently utilized by Targa based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- LEC is a technically feasible option expected to achieve a vendor-quoted NO_X emission rate of 3 g/hp-hr. [166]
- Unit replacement is a technically feasible option expected to achieve a NO_X emission rate of 0.5 g/hp/hr, consistent with the emissions standards for new natural gas-fired spark ignition lean burn engines in 20.2.50 NMAC.[167]
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, Harvest did not indicate that it intends to permanently retire any additional engines, so this option is not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants).

As indicated in Section C.3.5, the following determinations were made regarding the technical feasibility of identified control options for the boilers at EGPP:

- SNCR is not a technically feasible option, in this case, because the exhaust temperature of the boilers is too low.
- GCP is a technically feasible option and is currently utilized by Targa based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- SCR is a technically feasible option with an expected NO_X control efficiency of 90 percent.
- FGR is a technically feasible option expected to achieve a vendor-quoted NO_X emission rate of 30 ppm.
- LNB is a technically feasible option expected to achieve a vendor-quoted NO_X emission rate of 9 ppm.
- Unit replacement is a technically feasible option expected to achieve a NO_X emission rate of 9 ppm.

[166] Targa's initial FFA submittal in 2019 specified that 2.0 g/hp-hr was achievable according to a vendor. However, in its June 2023 FFA update, an email from Siemens Energy indicated that the appropriate target NO_X rate for LEC modifications of the RICE is 3.0 g/hp-hr.

[167] 20.2.50 NMAC contains varying emission standards for new natural gas-fired spark ignition engines based on engine type and rated brake horsepower. See Section 113, Table 2. Equivalent for the 2SLB RICE at EGPP would be subject to the NO_X standard for new lean burn engines >500 and <1,875 bhp (0.5 g/bhp-hr).

- Unit retirement is a technically feasible option. However, Targa did not indicate that it intends to permanently retire any of the affected boiler units, so this option is not evaluated further.

As indicated in Section C.3.6, the following determinations were made regarding the technical feasibility of identified control options for the ATS at EGPP:

- While a flare, SRU, or TO are technically feasible options, the use of an AGI well with redundant compression is an optimal approach to reducing emissions from ATS because emissions are only produced during AGI SSM/M events. Therefore, NMED did not evaluate these options.
- While improved flare design might reduce emissions somewhat during AGI SSM/M events, the potential marginal improvement in combustion efficiency – perhaps 1 to 2 percentage points – from the most optimized flare is not anticipated to be a cost-effective option for reducing SO_2 emissions from acid gas flaring during AGI SSM/M events. Therefore, NMED did not evaluate this option.

C.4.19.5 Four-Factor Analysis

In order to determine what control measures are necessary at EGPP to make reasonable progress, NMED conducted a FFA of potential control measures for NO_X for the NO_X units identified in section C.4.19.2 above. NMED did not conduct a FFA of potential control measures for SO_2 for EGPP's ATS because the most effective control available – an AGI well with redundant compression – is already being utilized at EGPP. States are required to consider four statutory factors – cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[168]

C.4.19.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X emissions reduced, of each technically feasible control option identified in section C.4.19.4 above. NMED utilized source-specific cost estimates provided by Targa in its calculations whenever possible. In cases where Targa failed to provide source-specific cost estimates or NMED found estimates provided by Targa to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[169]

NMED's cost effectiveness values for all technically feasible controls for the NO_X units at EGPP are summarized below. NMED believes these values were calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed cost effectiveness calculations for the NO_X units at EGPP and supporting documentation for NMED's cost estimates are provided in Appendix D.

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[168] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).

[169] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
B-01	FGR	$44,384	17.4	$3,000
	LNB	$80,201	23.5	$3,000
	SCR	$399,366	23.5	$17,000
	Replacement	$182,670	23.5	$8,000
B-02	FGR	$44,384	17.4	$3,000
	LNB	$80,201	23.5	$3,000
	SCR	$399,366	23.5	$17,000
	Replacement	$182,670	23.5	$8,000
C-01	LEC	$321,408	170.5	$2,000
	Replacement	$439,360	194.5	$2,000
C-02	LEC	$321,408	143.2	$2,000
	Replacement	$439,360	165.7	$3,000
C-03	LEC	$321,408	138.4	$2,000
	Replacement	$439,360	162.4	$3,000
C-04	LEC	$321,408	161.2	$2,000
	Replacement	$439,360	185.3	$2,000
C-05	LEC	$321,408	169.6	$2,000
	Replacement	$439,360	195.2	$2,000
C-06	LEC	$321,408	133.5	$2,000
	Replacement	$439,360	157.5	$3,000
C-07	LEC	$321,408	155.5	$2,000
	Replacement	$439,360	180.0	$2,000
C-01, C-02, C-03 [(1)]	Electrification	$950,592	536.8	$2,000
C-04, C-05, C-06 [(1)]	Electrification	$853,596	552.8	$2,000
C-07 and C-13 [(1)]	Electrification	$929,628	367.6	$3,000

[(1)] For purposes of its electrification analysis, Targa grouped certain RICE to reasonably match the capacity of one 3,250 hp EMD unit. Targa grouped Unit C-07 with Unit C-13 even though C-13 has been permanently retired.

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the NO_X units at EGPP:

- Targa did not provide a company-specific cost of capital, so the bank prime rate (7.5 percent as of December 2024) was used to determine the appropriate capital recovery factor.
- In its 2019 FFA submittal, Targa indicated that the addition of "turbochargers or externally driven blowers" would be necessary to accommodate LEC. Targa also indicated that it would have to significantly upgrade EGPP's electrical substation to operate blowers associated with LEC. Targa used these requirements to justify including $8.4M for substation upgrades and $164,000 per engine per year in additional electricity costs for 400 hp electric blowers in the updated LEC cost evaluation provided in its 8/4/23 submittal. These costs were omitted from NMED's evaluation for several reasons. First, no other FFA submitted to NMED references the need for an external

blower as part of a LEC retrofit on a 2SLB RICE. Every other FFA references the potential (or actual) need for a turbocharger – which is powered by the engine's exhaust and thus does not have a significant electric demand – as part of a LEC retrofit on a 2SLB RICE, including engines identical or nearly identical to the ones at EGPP. Second, the vendor quote Targa utilized in the updated LEC cost evaluation provided in its 8/4/23 submittal provides two "turnkey" cost estimates for LEC, one for units already equipped with turbochargers and one for units not equipped with turbochargers. The quote states that "a non-turbocharged unit would require a turbocharger" and other equipment/modifications to achieve the target emission rate of 3 g/bhp-hr. In its updated cost evaluation, Targa indicated that EGPP's engines are not turbocharged and used the higher vendor cost estimate for non-turbocharged units. Hence, Targa's own evaluation is premised on the addition of turbochargers, not blowers, to accommodate LEC. Finally, Targa did not state, or provide any details supporting, the idea that adding turbochargers, as opposed to blowers, would necessitate upgrades to EGPP's substation.

- The Total Capital Costs (TCC), Direct Annual Costs (DAC) and Indirect Annual Costs (OAC) of SCR were calculated using EPA's SCR Tool. An SCR retrofit factor of 1 (average difficulty) was applied, due to a lack of information from Targa supporting a higher retrofit factor.
- In its 8/4/23 submittal, Targa indicated that $8.4M in substation upgrades would be necessary to support electrification at EGPP. NMED accounted for these costs in its determination of cost effectiveness. However, Targa's estimate did not include costs associated with distribution line upgrades. Therefore, NMED's Total Capital Investment (TCI) for electrification may be underestimated.
- In its 8/4/23 submittal, Targa indicated that electrification would result in approximately $3.6M in annual O&M costs for electricity and engine maintenance. NMED believes these costs are exaggerated based on calculations performed using the electricity rate provided by Targa ($0.053/kW-h) and reasonable assumptions regarding incremental maintenance costs for EMD. Furthermore, Targa failed to account for fuel savings associated with the shutdown of the existing natural gas-fired engines in its estimate of annual O&M costs. Therefore, NMED replaced Targa's estimate with its own estimate based on engineering judgement.
- Targa, like most of the companies required to submit a FFA, did not provide information regarding the TCI associated with the replacement of the 2SLB RICE units at EGPP with new, functionally equivalent natural gas-fired units. NMED reviewed several publicly available resources with information that could be used to estimate the TCI of a replacement RICE[170] along with information provided by other companies with similar units. NMED determined that the most applicable cost metric ($ per hp basis) was provided by El Paso Natural Gas Company in support of their FFA submittals. NMED understands that the use of this metric is likely accurate to within ±30 percent, but also recognizes that various preliminary vendor quotes are often caveated with a similar degree of accuracy.
- Targa similarly did not provide information regarding the TCI associated with replacement of the boilers at EGPP with new boilers. Therefore, NMED used information provided by ERG for the replacement of a similar boiler at another facility to estimate these costs.

[170] This includes, but is not limited to, the U.S. EPA's Combined Heat and Power Catalog of Technologies (Reciprocating engines) and the U.S. Energy Information Agency's *Cost and Performance Characteristics of New Generating Technologies* in the 2023 Annual Energy Outlook.

C.4.19.5.2 Compliance Time

In its 2019 FFA submittal, Targa indicated it would take 7 years to implement LEC on the 2SLB RICE at EGPP. In its 2/17/20 submittal, Targa clarified that this estimate was based on the time necessary to install LEC on all 2SLB RICE at its Eunice, Monument and Saunders Gas Plants. NMED's FFA is specific to EGPP and does not consider the time necessary for compliance at other facilities when evaluating this factor. NMED's general assessment of the compliance time for LEC provided in Section C.3.1 is believed to be reasonably accurate.

Targa did not indicate how many years it would take to replace the 2SLB RICE at EGPP with new, functionally equivalent natural gas-fired units. NMED believes the general compliance times for like-kind replacement, provided in Section C.3.1, is reasonable.

In its 11/20/20 submittal, Targa estimated it would take 7-8 years to budget, design, procure, and construct all the equipment necessary to electrify the 2SLB RICE units at EGPP. NMED disagrees with this estimate based on information provided by other facilities and the implementation time of electrification projects at other facilities. NMED believes the general compliance time for electrification, provided in Section C.3.1, is more reasonable but recognizes several more years could be required considering the relative complexity.

Targa indicated it would take 5 years to implement FGR on the boilers at EGPP. NMED's general assessment of compliance time provided in Section C.3.5 is more reasonable. Targa did not indicate a timeline to implement LNB or replace the boilers. NMED's general assessment of compliance times provided in Sections C.3.5 is believed to be reasonably accurate.

Targa did not provide an estimate of the time necessary to implement SCR on the boilers at EGPP. NMED believes the general compliance time provided in Section C.3.5 is reasonable.

C.4.19.5.3 Remaining Useful Life

Despite the advanced age of the 2SLB RICE units at EGPP (>50 years), owners and operators of gas compression equipment in New Mexico have indicated that similar RICE would last at least 20 more years with proper maintenance. Twenty years is thus the estimated remaining useful life for LEC.

Manufacturers of new RICE will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new RICE are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement RICE is 30 years. The estimated useful life of a replacement boiler is also 30 years based on the same reasoning.

There is limited information about the useful life of EMD units, but research suggests the useful life is at least 25 years.

A vendor evaluation was provided that identified the useful life of FGR and LNB to be 30 years. Thirty years is thus the estimated remaining useful life for FGR and LNB.

Consistent with generally accepted EPA methodology and NMED's experience, the useful life of SCR is estimated to be 20 years.

C.4.19.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for 2SLB RICE and boilers at EGPP is provided in Sections C.3.1 and C.3.5, respectively.

C.4.19.5.5 Summary

NMED performed a FFA for all technically feasible control options for the NO_X units listed in Section C.4.19.2 above. The four statutory factors are discussed in Sections C.4.19.5.1 through C.4.19.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
B-01	FGR	$3,000	2-3	30	None
	LNB	$3,000	2-3	30	None
	SCR	$17,000	2-3	30	None
	Replacement	$8,000	3-4	30	None
B-02	FGR	$3,000	2-3	30	None
	LNB	$3,000	2-3	30	None
	SCR	$17,000	2-3	30	None
	Replacement	$8,000	3-4	30	None
C-01	LEC	$2,000	2-3	20	None
	Replacement	$2,000	3-4	30	None
C-02	LEC	$2,000	2-3	20	None
	Replacement	$3,000	3-4	30	None
C-03	LEC	$2,000	2-3	20	None
	Replacement	$3,000	3-4	30	None
C-04	LEC	$2,000	2-3	20	None
	Replacement	$2,000	3-4	30	None
C-05	LEC	$2,000	2-3	20	None
	Replacement	$2,000	3-4	30	None
C-06	LEC	$2,000	2-3	20	None
	Replacement	$3,000	3-4	30	None
C-07	LEC	$2,000	2-3	20	None
	Replacement	$2,000	3-4	30	None
C-01, C-02, C-03	Electrification	$2,000	4-6	25	None
C-04, C-05, C-06	Electrification	$2,000	4-6	25	None
C-07 and C-13	Electrification	$3,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

C.4.19.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[171]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For NO_X units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For NO_X units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective control is necessary to make reasonable progress. The sole exception to these general rules is the categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

NMED's FFA identified cost effective controls for EGPP Units B-01, B-02, C-01, C-02, C-03, C-04, C-05, C-06, and C-07. Based on its analysis of the four statutory factors and the decision-making criteria described above, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
B-01	LNB	23.5
B-02	LNB	23.5
C-01	Replacement	194.5
C-02	Replacement	165.7
C-03	Replacement	162.4
C-04	Replacement	185.3
C-05	Replacement	195.2
C-06	Replacement	157.5
C-07	Replacement	180.0

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
B-01	FGR	Less stringent than LNB
B-01	Replacement	Same stringency as LNB but less cost-effective

[171] See *supra* note 13.

Unit No.	Control Measure	Reason
B-02	FGR	Less stringent than LNB
B-02	Replacement	Same stringency as LNB but less cost-effective
C-01	LEC	Less stringent than replacement
C-01	Electrification	Categorically excluded
C-02	LEC	Less stringent than replacement
C-02	Electrification	Categorically excluded
C-03	LEC	Less stringent than replacement
C-03	Electrification	Categorically excluded
C-04	LEC	Less stringent than replacement
C-04	Electrification	Categorically excluded
C-05	LEC	Less stringent than replacement
C-05	Electrification	Categorically excluded
C-06	LEC	Less stringent than replacement
C-06	Electrification	Categorically excluded
C-07	LEC	Less stringent than replacement
C-07	Electrification	Categorically excluded

As noted above, NMED did not conduct a FFA of potential control measures for Units C-08, C-09, C-10, C-11, C-12, and C-13 because they have been permanently shut down and removed from EGPP's NSR permit. However, based on when they were retired, the resulting emissions reductions were realized during the second planning period. Therefore, NMED estimated the NO_X emissions reductions resulting from the retirement of these units by averaging 2016-2019 emissions reported by Harvest pursuant to 20.2.73 NMAC.[172] These emissions are summarized below.

Unit No.	Estimated NO_X Reductions (ton/yr)
C-08	144.0
C-09	32.7
C-10	18.9
C-11	30.2
C-12	40.6
C-13	225.6

NMED also did not conduct a FFA of potential control measures for EGPP's ATS. Because the most effective control available – an AGI well with redundant compression – is already being utilized at EGPP, NMED determined that reasonable progress does not require new controls on the ATS. However, based on when redundant compression was added to the AGI well, the resulting emissions reductions were realized during the second planning period. Therefore, NMED estimated the SO_2 reductions resulting from the addition of redundant compression to the AGI well using reported AGI SSM/M flaring emissions for acid gas flare F-01.

[172] NMED estimated the emissions reductions resulting from the retirement of Unit C-08 by averaging 2016-2018 emissions reported by Harvest, as it was shut down a year earlier than the other units.

Unit No.	Estimated SO_2 Reductions (ton/yr)
F-01	308.2 [(1)]

[(1)] Estimated reductions represent the difference between AGI SSM/M emissions from F-01 prior to installation of the backup compressor (416.7 ton/yr) and after (108.5 ton/yr).

Combining expected reductions from the controls NMED has determined are necessary to make reasonable progress and reductions resulting from recent retirements and the addition of redundant compression to the AGI well, NMED estimates the total emissions reductions at EGPP during the second planning period will be approximately 1,779.6 ton/yr of NO_X and 308.2 ton/yr of SO_2.

C.4.20 Targa Midstream Services – Monument Gas Plant

Resources used in NMED's FFA for Monument Gas Plant (MGP) include, but are not limited to, the following:

- The FFA completed by Trinity Consultants for Targa Midstream Services, LLC (Targa) and submitted to NMED on or about 11/1/19.
- Additional information provided by Targa on 12/13/19, 2/17/20, 3/12/20, 11/20/20, 2/16/21, and 8/4/23.
- A detailed discussion between Targa and NMED on 6/8/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- Memorandum from Ramboll to WRAP Oil and Gas Working Group - Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP region (March 23, 2020)
- FFAs developed for similar facilities in New Mexico and other states.

C.4.20.1 Facility Description

MGP is a natural gas processing facility located 2.8 miles west of Monument in Lea County, New Mexico at latitude 32° 36' 38", longitude -103° 18' 44". It is owned by Versado Gas Processors, LLC and operated by Targa, and currently operates under Title V Operating Permit No. P110-R3M1, which expires on April 12, 2025. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 68.2 miles.

The function of the facility is to process natural gas through inlet separation, an amine system for acid gas removal (carbon dioxide and hydrogen sulfide), dehydration for water removal, and the separation of methane from natural gas liquids. The facility is authorized for continuous operation, and its total potential to emit is 1012.8 tons per year of NO_X and 372.9 tons per year of SO_2.[173]

[173] AQB Title V Operating Permit No. P110-R3M1, Table 102.A.

C.4.20.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at MGP.[174]

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
C-01	2SLB RICE	Clark RA-8	<1956 (1)	800 hp
C-02	2SLB RICE	Clark RA-8	<1956 (1)	800 hp
C-04	2SLB RICE	Clark RA-6	<1956 (1)	600 hp
C-05	2SLB RICE	Clark RA-6	<1956 (1)	600 hp
C-06	2SLB RICE	Clark RA-6	<1956 (1)	600 hp
C-24	2SLB RICE	Clark HRA-8	<1696 (1)	880 hp
C-28	2SLB RICE	Cooper Bessemer GMVA-8	<1977 (1)	1,100 hp

(1) Targa's most recent Title V permit application does not provide a date of manufacture for Units C-01 through C-28, but indicates they were all constructed/reconstructed in 1956 (C-01 through C-06), 1969 (C-24), or 1977 (C-28). The date of manufacture necessarily precedes the construction/reconstruction date.

NMED also elected to evaluate the ATS at MGP for potential control measures for SO_2 due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). The ATS at MGP consists of an ATU (Unit AM-01), AGI well (Unit AGI), two electric AGI well compressors (Units AGI-C1 and AGI-C2), and an acid gas flare (Unit F-03). During normal operations, acid gas exiting the ATU is routed to the AGI well for disposal resulting in no emissions to the atmosphere. During AGI SSM/M events, acid gas is rerouted to the acid gas flare for disposal, which produces SO_2 emissions. AGI SSM/M flaring emissions are minimized via the second, redundant AGI well compressor, which provides compression when the primary AGI well compressor fails or is taken out of service for maintenance, allowing for continued use of the AGI well when flaring would otherwise be required.

C.4.20.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. Targa did not request a future utilization adjustment for MGP. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the emissions units at MGP.

For the emissions units at MGP requiring a FFA of potential control measures for NO_X ("NO_X units"), NMED calculated baseline actual emissions by multiplying representative annual operating hours by the NO_X emission rates reported in Targa's most recent periodic emissions test report(s).[175,] Because the NO_X units at MGP operate at varying loads, NMED conservatively adjusted reported emission rates to 100

[174] See Chapter 6, Selection of Sources for Control Measures Analysis, for a discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.
[175] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.

percent load to represent worst-case emissions.[176] Reported and adjusted emission rates for the NO_X units at MGP are summarized below.

Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr @ 100% load)
C-01	NA (1)	---	---	28.5 (2)
C-02	6/14/23	27.4	96%	28.5
C-04	NA (1)	---	---	24.0 (2)
C-05	6/14/23	22.1	92%	24.0
C-06	6/14/23	9.3	96%	9.7
C-24	6/15/23	37.6	94%	40.0
C-28	6/16/23	15.8	92%	17.2

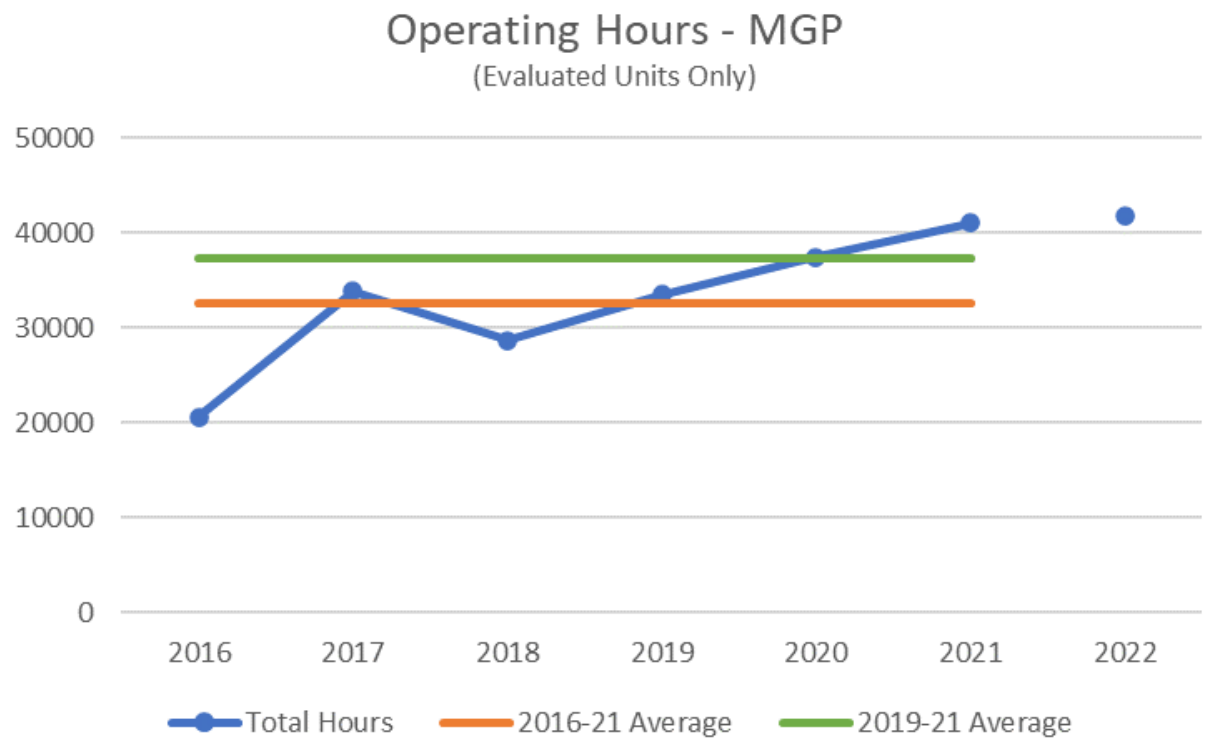
(1) NA = Not Available

(2) The adjusted emissions of Unit C-02 were used as a surrogate for identical Unit C-01, as NMED was unable to locate a recent emissions test report for this unit. The adjusted emissions of Unit C-05 were used as a surrogate for identical Unit C-04 for the same reason.

To determine representative annual operating hours for the NO_X units at MGP, NMED analyzed 2016-2021 operating hours reported by Targa pursuant to 20.2.73 NMAC. NMED was in receipt of Targa's reported 2022 operating hours at the time of its analysis, but the data were still undergoing internal QA/QC checks and had not been certified yet, so NMED excluded them from its analysis. 2016-2021 operating hours for the NO_X units at MGP are summarized and plotted below; reported 2022 operating hours are included for informational purposes only.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
C-01	2357	6257	2965	4813	2388	648	0
C-02	4069	4689	4217	5609	4992	6630	8604
C-04	990	3285	3912	3525	600	756	0
C-05	3938	4730	4342	7255	8760	8550	8540
C-06	2035	6553	3879	3641	8590	8244	8488
C-24	6610	6541	8501	8683	8478	8511	8421
C-28	573	1798	841	0	3624	7719	7749

[176] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.



As shown above, MGP's operating hours have increased steadily in recent years, with preliminary 2022 data suggesting utilization plateaued in 2021. Therefore, NMED determined that 2019-2021 average operating hours are representative for the NO_X units at MGP.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the NO_X units at MGP are summarized below.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
C-01	28.5	2616	37.3
C-02	28.5	5744	82.0
C-04	24.0	1627	19.5
C-05	24.0	8188	98.3
C-06	9.7	6825	33.1
C-24	40.0	8557	171.1
C-28	17.2	3781	32.5

C.4.20.4 Technical Feasibility of Available Controls

As indicated in Section C.3.1, the following determinations were made regarding the technical feasibility of identified control options for the 2SLB RICE at MGP:

- SCR, SNCR, and NSCR are not technically feasible options.

- GCP is a technically feasible option and is currently utilized by Targa based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- LEC is a technically feasible option expected to achieve a vendor-quoted NO_X emission rate of 3.0 g/hp-hr.[177]
- Unit replacement is a technically feasible option expected to achieve a NO_X emission rate of 0.5 g/hp-hr, consistent with the emissions standards for new natural gas-fired spark ignition lean burn engines in 20.2.50 NMAC. [178]
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, Targa has not indicated that it intends to permanently retire any of the affected units, so this option is not evaluated further.
- Electrification is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants).

As indicated in Section C.3.6, the following determinations were made regarding the technical feasibility of identified control options for the ATS at MGP:

- While a flare, SRU, or TO are technically feasible options, the use of an AGI well with redundant compression is an optimal approach to reducing emissions from ATS because emissions are only produced during AGI SSM/M events. Therefore, NMED did not evaluate these options.
- While improved flare design might reduce emissions somewhat during AGI SSM/M events, the potential marginal improvement in combustion efficiency – perhaps 1 to 2 percentage points – from the most optimized flare is not anticipated to be a cost-effective option for reducing SO_2 emissions from acid gas flaring during AGI SSM/M events. Therefore, NMED did not evaluate this option.

C.4.20.5 Four-Factor Analysis

In order to determine what control measures are necessary at MGP to make reasonable progress, NMED conducted a FFA of potential control measures for NO_X for the NO_X units identified in section C.4.20.2 above. NMED did not conduct a FFA of potential control measures for SO_2 for MGP's ATS because the most effective control available – an AGI well with redundant compression – is already being utilized at MGP. States are required to consider four statutory factors – cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[179]

C.4.20.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X emissions reduced, of each technically feasible control option identified in section C.4.20.4 above.

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[177] Targa's initial FFA submittal in 2019 indicated that 2.0 g/hp-hr was achievable, according to a vendor. However, in its June 2023 FFA update, an email from Siemens Energy indicated that the appropriate target NO_X emission rate for LEC modifications of the RICE at MGP is 3.0 g/hp-hr.

[178] 20.2.50 NMAC contains varying emission standards for new natural gas-fired spark ignition engines based on engine type and rated brake horsepower. See Section 113, Table 2. Equivalent replacements for the 2SLB RICE at MGP would be subject to the NO_X standard for new lean burn engines >500 and <1,875 bhp (0.5 g/bhp-hr).

[179] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).

NMED utilized source-specific cost estimates provided by Targa in its calculations whenever possible. In cases where Targa failed to provide source-specific cost estimates or NMED found estimates provided by Targa to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[180]

NMED's cost effectiveness values for all technically feasible controls for the NO_X units at MGP are summarized below. NMED believes these values were calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed cost effectiveness calculations for the NO_X units at MGP and supporting documentation for NMED's cost estimates are provided in Appendix D.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
C-01	LEC	$321,408	30.4	$11,000
	Replacement	$292,907	36.2	$8,000
C-02	LEC	$321,408	66.8	$5,000
	Replacement	$292,907	79.4	$4,000
C-04	LEC	$321,408	16.3	$20,000
	Replacement	$219,680	19.0	$12,000
C-05	LEC	$321,408	82.1	$4,000
	Replacement	$219,680	95.6	$2,000
C-06	LEC	$321,408	19.5	$16,000
	Replacement	$219,680	30.8	$7,000
C-24	LEC	$321,408	146.2	$2,000
	Replacement	$322,198	167.0	$2,000
C-28	LEC	$266,171	18.7	$14,000
	Replacement	$402,747	30.2	$13,000
C-01, C-02 (1)	Electrification	$770,731	119.3	$6,000
C-04, C-05, C-06 (1)	Electrification	$839,974	150.9	$6,000
C-24	Electrification	$742,765	171.1	$4,000
C-28	Electrification	$1,085,102	32.5	$33,000

(1) For purposes of its electrification analysis, Targa grouped certain RICE to reasonably match the capacity of one 1,750 hp EMD unit.

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the NO_X units at MGP:

[180] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

- Targa did not provide a company-specific cost of capital, so the bank prime rate (7.5 percent as of December 2024) was used to determine the appropriate capital recovery factor.
- In its 2019 FFA submittal, Targa indicated that the addition of "turbochargers or externally driven blowers" would be necessary to accommodate LEC. Targa also indicated that it would have to significantly upgrade MGP's electrical substation to operate blowers associated with LEC. Targa used these requirements to justify including $6.3M for substation upgrades and $164,000 per engine per year in additional electricity costs for 400 hp electric blowers in the updated LEC cost evaluation provided in its 8/4/23 submittal. These costs were omitted from NMED's evaluation for several reasons. First, no other FFA submitted to NMED references the need for an external blower as part of a LEC retrofit on a 2SLB RICE. Every other FFA references the potential (or actual) need for a turbocharger – which is powered by the engine's exhaust and thus does not have a significant electric demand – as part of a LEC retrofit on a 2SLB RICE, including engines identical or nearly identical to the ones at MGP. Second, the vendor quote Targa utilized in the updated LEC cost evaluation provided in its 8/4/23 submittal provides two "turnkey" cost estimates for LEC, one for units already equipped with turbochargers and one for units not equipped with turbochargers. The quote states that "a non-turbocharged unit would require a turbocharger" and other equipment/modifications to achieve the target emission rate of 3 g/bhp-hr. In its updated cost evaluation Targa indicated that, with the exception of Unit C-28, MGP's engines are not turbocharged and used the higher vendor cost estimate for non-turbocharged units (Targa used the lower vendor cost estimate for turbocharged units for Unit C-28). Hence, Targa's own evaluation is premised on the addition of turbochargers, not blowers, to accommodate LEC. Finally, Targa did not state, or provide any details supporting, the idea that adding turbochargers, as opposed to blowers, would necessitate upgrades to MGP's substation.
- In its 8/4/23 submittal, Targa indicated that $6.3M in substation upgrades would be necessary to support electrification at MGP. NMED accounted for these costs in its determinations of cost effectiveness. However, Targa's estimate did not include any costs associated with distribution line upgrades. Therefore, NMED's Total Capital Investment (TCI) estimates for electrification may be underestimated.
- In its 8/4/23 submittal, Targa indicated that electrification would result in approximately $2M in annual O&M costs for electricity and engine/compressor maintenance. NMED believes these costs are exaggerated based on calculations performed using the electricity rate provided by Targa ($0.053/kW-h) and reasonable assumptions regarding incremental maintenance costs for EMD. Furthermore, Targa failed to account for fuel savings associated with the shutdown of the existing natural gas-fired engines in its estimate of annual O&M costs. Therefore, NMED substituted its own estimate of annual O&M costs based on engineering judgement.
- Targa, like most of the companies required to submit a FFA, did not provide information regarding the Total Capital Investment (TCI) associated with the replacement of the 2SLB RICE at MGP with new, functionally equivalent natural gas-fired units. NMED reviewed several publicly available resources with information that could be used to estimate the TCI of a replacement RICE along with information provided by other companies with similar units. NMED determined that the most applicable cost metric ($ per hp basis) was provided by El Paso Natural Gas Company in support of their FFA submittals. NMED understands that the use of this metric is likely accurate to within ±30 percent, but also recognizes that various preliminary vendor quotes are often caveated with a similar degree of accuracy.

C.4.20.5.2 Compliance Time

In its 2019 FFA submittal, Targa indicated it would take 7 years to implement LEC on the 2SLB RICE at MGP. In its 2/17/20 submittal, Targa clarified that this estimate was based on the time necessary to install LEC on all 2SLB RICE at its Eunice, Monument and Saunders Gas Plants. NMED's FFA is specific to MGP and does not consider the time necessary for compliance at other facilities when evaluating this factor. NMED's general assessment of the compliance time for LEC provided in Section C.3.1 is believed to be reasonably accurate.

Targa did not indicate how many years it would take to replace the 2SLB RICE units at MGP with new, functionally equivalent natural gas-fired units. NMED believes the general compliance time for like-kind replacement, provided in Section C.3.1, is reasonable.

In its 11/20/20 submittal, Targa estimated it would take 7-8 years to budget, design, procure, and construct all the equipment necessary to electrify the 2SLB RICE units at MGP. NMED disagrees with this estimate based on information provided by other facilities and the implementation time of electrification projects at other facilities. NMED believes the general compliance time for electrification, provided in Section C.3.1, is more reasonable but recognizes several more years could be required considering the relative complexity.

C.4.20.5.3 Remaining Useful Life

Despite the advanced age of the units at MGP (~50 to 70 years), owners and operators of gas compression equipment in New Mexico have indicated that similar RICE would last at least 20 more years with proper maintenance. Twenty years is thus the estimated remaining useful life for LEC.

Manufacturers of new RICE will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new RICE are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement RICE is 30 years.

There is limited information about the useful life of EMD units, but research suggests the useful life is at least 25 years.

C.4.20.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for 2SLB RICE at MGP is provided in Section C.3.1.

C.4.20.5.5 Summary

NMED performed a FFA for all technically feasible control options for the NO_X units listed in Section C.4.20.2 above. The four statutory factors are discussed in Sections C.4.20.5.1 through C.4.20.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
C-01	LEC	$11,000	2-3	20	None
	Replacement	$8,000	3-4	30	None
C-02	LEC	$5,000	2-3	20	None
	Replacement	$4,000	3-4	30	None
C-04	LEC	$20,000	2-3	20	None
	Replacement	$12,000	3-4	30	None
C-05	LEC	$4,000	2-3	20	None
	Replacement	$2,000	3-4	30	None
C-06	LEC	$16,000	2-3	20	None
	Replacement	$7,000	3-4	30	None
C-24	LEC	$2,000	2-3	20	None
	Replacement	$2,000	3-4	30	None
C-28	LEC	$14,000	2-3	20	None
	Replacement	$13,000	3-4	30	None
C-01, C-02	Electrification	$6,000	4-6	25	None
C-04, C-05, C-06	Electrification	$6,000	4-6	25	None
C-24	Electrification	$4,000	4-6	25	None
C-28	Electrification	$33,000	4-6	25	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

C.4.20.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[181]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For NO_X units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For NO_X units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective

[181] See *supra* note 13.

control is necessary to make reasonable progress. The sole exception to these general rules is the categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

NMED's FFA identified cost-effective controls for MGP Units C-01, C-02, C-04, C-05, C-06, and C-24. Based on its analysis of the four statutory factors and the decision-making criteria described above, NMED determined that the following cost-effective controls are necessary to make reasonable progress:

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
C-01	Replacement	36.2
C-02	Replacement	79.4
C-05	Replacement	95.6
C-06	Replacement	30.8
C-24	Replacement	167.0

NMED rejected the following cost-effective controls for the reason(s) stated:

Unit No.	Control Measure	Reason
C-01	Electrification	Categorically excluded
C-02	LEC	Less stringent than replacement
C-02	Electrification	Categorically excluded
C-04	Electrification	Categorically excluded
C-05	LEC	Less stringent than replacement
C-05	Electrification	Categorically excluded
C-06	Electrification	Categorically excluded
C-24	LEC	Less stringent than replacement
C-24	Electrification	Categorically excluded

NMED's FFA did not identify any cost-effective controls for MGP Unit C-28. Therefore, NMED determined that reasonable progress does not require new controls on this unit.

As noted above, NMED did not conduct a FFA of potential control measures for MGP's ATS. Because the most effective control available – an AGI well with redundant compression – is already being utilized at MGP, NMED determined that reasonable progress does not require new controls for the ATS. However, based on when redundant compression was added to the AGI well, the resulting emissions reductions were realized during the second planning period. Therefore, NMED estimated the SO_2 reductions resulting from the addition of redundant compression to the AGI well using reported AGI SSM/M flaring emissions for acid gas flare F-03. These reductions are summarized below.

Unit No.	Estimated SO_2 Reductions (ton/yr)
F-03	112.2[(1)]

[(1)] Estimated reductions represent the difference between AGI SSM/M emissions from F-03 prior to installation of the backup compressor (125.4 ton/yr) and after (13.2 ton/yr).

Combining expected reductions from the controls NMED has determined are necessary to make reasonable progress and reductions resulting from the addition of redundant compression to the AGI

well, NMED estimates the total emissions reductions at MGP during the second planning period will be approximately 409.0 ton/yr of NO_X and 112.2 ton/yr of SO_2.

C.4.21 Targa Midstream Services – Saunders Gas Plant

Saunders Gas Plant (SGP) is a former natural gas processing facility located 15 miles northwest of Lovington in Lea County, New Mexico at latitude 33° 03' 26", longitude -103° 36' 27". It is owned by Versado Gas Processors, LLC and operated by Targa Midstream Services, LLC (Targa), and previously operated under Title V Operating Permit No. P111-R3. The shortest distance to the boundary of the nearest Class I Area, Salt Creek Wilderness Area, is approximately 56.4 miles. Notably, Salt Creek Wilderness Area is the only Class I Area in New Mexico projected to be above the URP glidepath in 2028 and for which a robust demonstration is required.[182]

SGP was one of 23 facilities selected for an analysis of potential control measures when NMED performed the source screening described in Section C.2 in 2019. NMED originally selected nine 2SLB RICE (Units C-01, C-02, C-03, C-04, C-05, C-06, C-07, C-08, and C-09) and three 4SRB RICE (Units G-01, G-02 and G-03) for an analysis of potential control measures for NO_X in the second planning period. NMED also elected to evaluate the ATS at SGP (comprising Units A-01, F-01, F-03, and I-01) for potential control measures for SO_2 due to the potential for significant emissions, during normal operations and/or SSM/M events, from some of the controls commonly used to dispose of ATS acid gas streams (e.g., flares). However, Targa idled the facility in 2021, and later informed NMED that it had decided to permanently shut down gas plant operations, remove all equipment selected for analysis in the second planning period from SGP's permits, and re-permit the few remaining sources under an Oil and Gas General Construction Permit. On May 30, 2024, Targa submitted an administrative permit revision removing Units C-01, C-02, C-03, C-04, C-05, C-06, C-07, C-08, C-09, G-01, G-02, G-03, A-01, F-01, F-03, and I-01 from NSR Permit No. 0315-M4R2 and Title V Permit No. P111-R3, and voluntarily discontinuing the Title V.

Because Targa has shut down gas plant operations at SGP, removed all of the units selected for analysis in the second planning period from SGP's NSR and Title V permits, and discontinued the Title V, NMED did not perform a FFA of potential control measures for any of these units. EPA guidance provides that a state may forgo a full FFA if a source is already "effectively controlled" and the state can demonstrate why a FFA would not result in new controls and would therefore be a futile exercise.[183] NMED considers it self-evident that a FFA of potential control measures for retired units at a facility that has been shut down would be futile. There is no more effective control than retirement, which reduces emissions by 100 percent. Therefore, NMED has determined that Units C-01, C-02, C-03, C-04, C-05, C-06, C-07, C-08, C-09, G-01, G-02, G-03, A-01, F-01, F-03, and I-01 are effectively controlled by virtue of their retirement due to the shutdown of gas plant operations at SGP, and that a FFA could only result in the conclusion that no further controls are necessary to make reasonable progress.

Based on when SGP was shut down, the emissions reductions resulting from the retirement of the affected units were realized during the second planning period. Therefore, NMED estimated the NO_X emissions reductions resulting from the retirement of SGP Units C-01, C-02, C-03, C-04, C-05, C-06, C-07,

[182] See Chapter 10, Progress, Degradation, and URP Glidepath Checks for Class I Areas in New Mexico, for NMED's robust demonstration for Salt Creek Wilderness Area.

[183] EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021) at 5.

C-08, C-09, G-01, G-02, and G-03 and the SO_2 emissions reductions resulting from the retirement of the units comprising the ATS by averaging 2016-2020 emissions reported by Targa pursuant to 20.2.73 NMAC. These emissions are summarized below.

Pollutant	2016 Emissions (tons)	2017 Emissions (tons)	2018 Emissions (tons)	2019 Emissions (tons)	2020 Emissions (tons)	Average Emissions (ton/yr)
NO_X	599.0	636.6	696.3	713.8	514.0	632.0
SO_2	385.6	561.0	247.3	226.6	3.7	284.8

C.4.22 Tri-State Generation & Transmission Association – Prewitt Escalante Generating Station

Prewitt Escalante Generating Station (PEGS) is a former 268 MW coal-fired electric power plant located 4 miles north of Prewitt in McKinley County, New Mexico at latitude 35° 24' 57", longitude -108° 04' 58". It is owned by Tri-State Generation and Transmission Association, Inc. (Tri-State), and was one of 23 facilities selected for an analysis of potential control measures when NMED performed the source screening described in Section C.2 in 2019. However, Tri-State subsequently shut down PEGS on August 31, 2020, and NMED voluntarily discontinued its Title V permit (Permit No. P012-R3) as of September 28, 2020.

Tri-State's shutdown of PEGS occurred in two phases. Phase 1, completed on August 31, 2020, included the permanent shutdown of the main coal-fired boiler, associated coal and limestone handling equipment, and cooling tower after all existing coal stored at the site was combusted. Phase 2, completed on January 28, 2021, included the transfer of ownership and operation of the auxiliary boiler and water treatment plant to McKinley Paper Company's Prewitt Mill. All previously shutdown or transferred equipment was subsequently removed from PEGS' NSR permit (Permit No. 0285-M5); the only remaining emissions units include the plant heating boiler, gasoline tank, fire pump engine, and fugitive sources associated with final site restoration. According to Tri-State, these units "will allow the continued decommissioning of PEGS until total facility closure."[184] Tri-State's timeline to fully decommission the plant is unknown.

NMED originally selected the main boiler for an analysis of potential control measures for NO_X and SO_2 in the second planning period, and the auxiliary boiler and plant heating boiler for an analysis of potential control measures for NO_X. However, because PEGS has since been shut down and is in the process of being decommissioned, NMED did not perform a FFA of potential control measures for any of these units. With regard to the main boiler, EPA guidance provides that a state may forgo a full FFA if a source is already "effectively controlled" and the state can demonstrate why a FFA would not result in new controls and would therefore be a futile exercise.[185] NMED considers it self-evident that a FFA of potential control measures for a retired unit at a facility that has been shut down and is the process of being decommissioned would be futile. There is no more effective control than retirement, which reduces emissions by 100 percent, and the decommissioning of PEGS will make it impossible to add new controls. Therefore, NMED has determined that the main boiler is effectively controlled by virtue of its

[184] Air Quality Permit #0285-M4-R2 Significant Revision Application (February 10, 2021).
[185] EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021) at 5.

retirement due to the shutdown of PEGS, and that a FFA could only result in the conclusion that no further controls are necessary to make reasonable progress.

With regard to the auxiliary boiler, McKinley Paper Company's Prewitt Mill is a minor source and thus exempt from analysis in the second planning period. As described in Section C.2, NMED limited its tier one source screening to Title V facilities and only selected a subset of those for analysis. As such, the transfer of the auxiliary boiler to Prewitt Mill removed it from consideration during the second planning period, although it could be selected for analysis in a future planning period as NMED expands the universe of sources evaluated beyond just Title V facilities.

Finally, with regard to the plant heating boiler, NMED believes it has sufficient information to conclude that there are no cost-effective controls without performing a full FFA. The plant heating boiler is currently limited to 4,350 hours of operation per calendar year to ensure that pipes and other equipment don't freeze in the winter months but has averaged just 2,204 hours of operation per year since PEGS shut down, resulting in 11.6 tons per year of NO_X emissions on average.[186] This suggests that, based on a maximum achievable control efficiency of approximately 90%, the potential emissions reductions from new controls are about 10 tons per year at best. Furthermore, the annualized costs of any new controls would be grossly inflated given that their remaining useful life would be limited to the relatively short time likely required to finish decommissioning the plant. High annualized costs coupled with low expected emissions reductions yield high cost effectiveness values, and based its experience and FFAs conducted for other facilities, NMED is confident that the cost effectiveness of any new controls for PEGS' plant heating boiler would greatly exceed its $10,000/ton cost effectiveness threshold.[187] Therefore, NMED has determined that reasonable progress does not require new controls on this unit.

Based on when PEGS was shut down, the emissions reductions resulting from the retirement of the main boiler were realized during the second planning period. Therefore, NMED estimated the NO_X and SO_2 emissions reductions resulting from the retirement of the main boiler by averaging 2016-2019 emissions reported by Tri-State pursuant to 20.2.73 NMAC. These emissions are summarized below.

Pollutant	2016 Emissions (tons)	2017 Emissions (tons)	2018 Emissions (tons)	2019 Emissions (tons)	Average Emissions (ton/yr)
NO_X	2,436.7	2,124.8	2,441.9	2,250.2	2,313.4

C.4.23 Xcel Energy – Cunningham Station Power Plant

Resources used in NMED's FFA for Cunningham Station Power Plant (CSPP) include, but are not limited to, the following:

[186] Based on 2020 and 2021 emission inventory data. PEGS transitioned to a minor source when shutdown and transferred equipment was removed from its NSR permit in 2021. Therefore, it was no longer required to submit an annual emission inventory starting in 2022.

[187] This conclusion is supported by Tri-State's initial FFA for PEGS, which estimated cost effectiveness values ranging from $19,410 to $33,653/ton (2019$) for plant heating boiler NO_X controls. The FFA was completed prior to the decision to shut down the plant and therefore assumed a remaining useful life of 20 to 30 years for all controls.

- The FFA completed by Trinity Consultants for Xcel Energy (Xcel) and submitted to NMED on or about 11/1/19.
- Additional information provided by Xcel on 2/14/20, 11/2/20, 1/25/21, and 7/18/23.
- A detailed discussion between Xcel and NMED on 6/22/23.
- NMED's archive of files and documentation related to the facility, including but not limited to permits, emissions test reports, and operating hours and other emission inventory data.
- U.S. EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019) and Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021).
- FFAs developed for similar facilities in New Mexico and other states.

C.4.23.1 Facility Description

CSPP is a 487 MW electric power plant located 12.5 miles west of Hobbs in Lea County, New Mexico at latitude 32° 42' 44", longitude -103° 21' 13". It is owned and operated by Southwestern Public Service Company, a subsidiary of Xcel, and currently operates under Title V Operating Permit No. P080-R4, which expires on April 9, 2026. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 69.4 miles.

The function of the facility is to provide commercial electric power using boilers and turbines fueled with natural gas. The facility is authorized for continuous operation,[188] and its total potential to emit is 4072.5 tons per year of NO_X and 155.8 tons per year of SO_2.[189]

C.4.23.2 Evaluated Units

NMED determined that a FFA of potential control measures for NO_X was required for the following emissions units at CSPP:[190]

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
1	Boiler	Combustion Engineering 9752	<1957 (1)	82 MW
2	Boiler	Combustion Engineering 19813	<1965 (1)	234 MW
3	Turbine	Westinghouse 501D5	<1997 (1)	115 MW
4	Turbine	Westinghouse 501D5	<1997 (1)	115 MW

(1) Xcel's most recent Title V permit application does not provide a date of manufacture for any of the units at CSPP, but indicates that Units 1 and 2 were constructed/reconstructed in 1957 and 1965, respectively, and Units 3 and 4 were constructed/reconstructed in 1997. The date of manufacture necessarily precedes the construction/reconstruction date.

NMED also determined that a FFA of potential control measures for SO_2 was required for CSPP Units 3 and 4. However, due to the high volumetric flow rate and very low SO_2 concentration of CT exhaust, no technically or economically feasible SO_2 controls exist for these units. CT SO_2 emissions are a function of the sulfur content of the fuel gas. As a result, limiting the fuel sulfur content is the only practicable means of reducing CT SO_2 emissions. CSPP Units 3 and 4 are already subject to fuel total sulfur content

[188] The boilers at CSPP may operate on a continuous basis, but the turbines are subject to annual limits on operating hours and the number of startup and shutdown cycles.
[189] AQB Title V Operating Permit No. P080-R4, Table 102.A.
[190] See Chapter 6, Selection of Sources for Control Measures Analysis, for a discussion of NMED's two-tiered process for selecting sources and emissions units requiring a FFA of potential control measures for NO_X and/or SO_2.

limits representing best available control technology (BACT) and emit less than one ton of SO_2 per year on average.[191] Therefore, NMED did not evaluate Units 3 and 4 for potential control measures for SO_2, only NO_X.

C.4.23.3 Projected Actual Emissions

Projected actual emissions represent estimated 2028 emissions absent any additional controls. NMED estimated projected actual emissions by applying a future utilization adjustment to baseline (i.e., current) actual emissions if the owner requested this adjustment. Xcel did not request a future utilization adjustment for CSPP. Therefore, NMED did not apply one, and projected actual emissions equal baseline actual emissions for the emissions units at CSPP.

NMED calculated baseline actual emissions for the emissions units at CSPP by multiplying representative annual operating hours by the NO_X emission rates reported in Xcel's most recent periodic emissions test report(s).[192,] Because the emissions units at CSPP operate at varying loads, NMED conservatively adjusted reported emission rates to 100 percent load to represent worst-case emissions.[193] Reported and adjusted emission rates for the emissions units at CSPP are summarized below.

Unit No.	Test Date	Reported NO_X Emissions (lb/hr)	Load During Test (%)	Adjusted NO_X Emissions (lb/hr at 100% load)
1	NA [(1)]	---	---	120.7 [(3)]
2	12/28/21	0.154	NP [(2)]	300.5
3	6/29/23	0.057	NP [(2)]	79.8 [(4)]
4	7/19/23	0.048	NP [(2)]	67.2 [(4)]

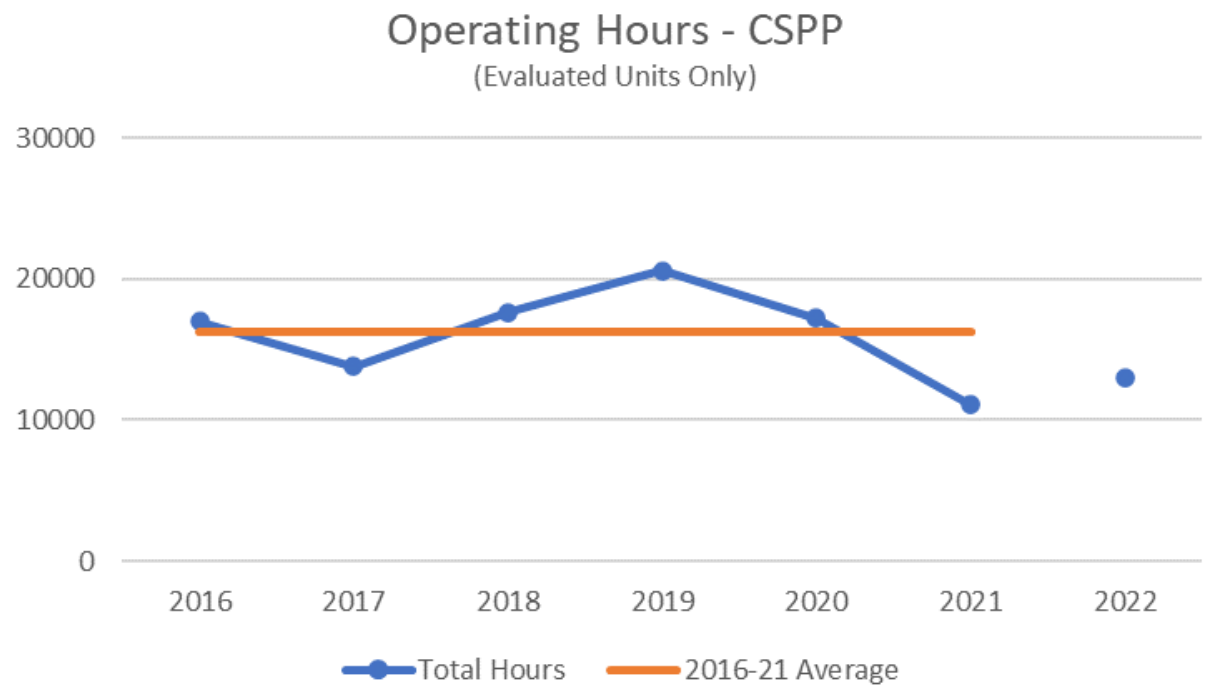
[(1)] NA = Not Available
[(2)] NP = Not Provided
[(3)] The reported emission rate (in lb/MMBtu) of Unit 2 was used as a surrogate for Unit 1, as NMED was unable to locate a recent emissions test report for this unit.
[(4)] Assumed the reported emission rates of Units 3 and 4 are representative of emissions at 100 percent load, as load was not provided in the emissions test reports for these units.

To determine representative annual operating hours for the emissions units at CSPP, NMED analyzed 2016-21 operating hours reported by Xcel pursuant to 20.2.73 NMAC. NMED was in receipt of Xcel's reported 2022 operating hours at the time of its analysis, but the data were still undergoing internal QA/QC checks and had not been certified yet, so NMED excluded them from its analysis. 2016-21 operating hours for the emissions units at CSPP are summarized and plotted below; reported 2022 operating hours are included for informational purposes only.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
1	4506	4336	6373	6927	6295	1379	728
2	8040	6833	4887	4717	4621	5578	7061

[191] Based on 2016-2022 emission inventory data.
[192] Emissions test reports were obtained from NMED's Air Quality Bureau Compliance Reporting System.
[193] NMED assumed a linear relationship between emissions and load for purposes of this adjustment. NMED recognizes that this relationship is likely not always linear but generally lacks sufficient information to characterize it for individual emissions units.

Unit No.	2016 Hours	2017 Hours	2018 Hours	2019 Hours	2020 Hours	2021 Hours	2022 Hours
3	1597	996	2168	4066	3358	2003	1869
4	2848	1611	4217	4870	2963	2120	3368



As shown above, CSPP's year-over-year operating hours have risen and fallen in recent years, with no obvious pattern and no discernible impact from the pandemic in 2020. Therefore, NMED determined that 2016-2021 average operating hours are representative for the emissions units at CSPP.

Adjusted emissions rates, representative annual operating hours, and baseline actual emissions for the emissions units at CSPP are summarized below.

Unit No.	Adjusted Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual Emissions (ton/yr)
1	120.7	4969	300.0
2	300.5	5779	868.2
3	79.8	2365	94.4
4	67.2	3105	104.3

C.4.23.4 Technical Feasibility of Available Controls

As indicated in Section C.3.4, the following determinations were made regarding the technical feasibility of identified control options for the CT at CSPP:

- DLN and SNCR are not technically feasible options.[194]
- GCP is a technically feasible option and is currently utilized by Xcel based on its compliance with the operating, maintenance, and testing requirements in its Title V permit. As a result, GCP is not evaluated further. (This determination is consistent with FFA completed in other states.)
- Water injection is a technically feasible option expected, according to the manufacturer, to reduce the concentration of NO_X in the exhaust by approximately 4.0 ppm.
- SCR is a technically feasible option expected to achieve a NO_X control efficiency of 90 percent.[195]
- Unit replacement is a technically feasible option expected to achieve a NO_X emission rate of 9.0 ppm, consistent with the emissions standards for new natural gas-fired turbines in 20.2.50 NMAC.[196]
- Unit retirement is a technically feasible option that would result in a 100 percent reduction of NO_X (and all other pollutants). However, Xcel did not indicate that it intends to permanently retire the units, which are currently scheduled to shut down in 2040, earlier than their current retirement date, so this option was not evaluated further.

Regarding the boilers at CSPP, in a detailed discussion with NMED on 6/22/23, Xcel indicated that Units 1 and 2 were scheduled to be shut down by 12/31/25 and 12/31/28, respectively. However, the New Mexico Public Regulation Commission (PRC) issued an order on 10/19/23 adopting a Certification of Stipulation requiring Xcel to retire Unit 1 by 12/31/23,[197] and another order on 5/30/24 approving Xcel's request to extend the service life of Unit 2 from 2025 to 2027 and retire it in 2027.[198] Therefore, neither unit is expected to operate beyond the end of the second planning period (Unit 1 appears to be shut down already based on EPA Clean Air Markets Program data), which would preclude the installation of new controls. However, because the current retirement schedule is not a federally enforceable requirement, NMED evaluated SCR, which is the only technically feasible control option for the boilers at CSPP,[199] as a backstop in case their retirement dates slip and one or both units continue to operate beyond the end of the second planning period.

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[194] A version of DLN is already installed on the CT at CSPP which results in NO_X emissions in the 15 to 25 ppm range. According to the manufacturer, improved DLN (with lower NO_X) is not available.

[195] Xcel assumed a NO_X control efficiency of 80% for Units 1 and 2 and 65% for Units 3 and 4 in the SCR evaluations provided in its initial FFA. While NMED disagrees with these assumptions, NMED notes that in its own evaluation, SCR remains cost effective for Units 1 and 2 even if the control efficiency is reduced to 80%.

[196] Part 50 does not apply to CSPP, but the emissions standard for new NG-fired CT >15,900 hp is believed to be a reasonable surrogate for equivalent replacements for Units 3 and 4.

[197] New Mexico Public Regulation Commission, In the Matter of Southwestern Public Service Company's Application For: (1) Revision of Its Retail Rates Under Advice Notice No. 312; (2) Authority to Abandon Its Plant X Unit 1, Plant X Unit 2, and Cunningham Unit 1 Generating Stations and Amend the Abandonment Date of Tolk Generating Station; and (3) Other Associated Relief, Docket No. 22-00286-UT.

[198] New Mexico Public Regulation Commission, In the Matter of Southwestern Public Service Company's Application Requesting: (1) Issuance of a Certificate of Public Convenience and Necessity to Construct and Operate Solar Generation and Battery Storage Projects and Associated Facilities; (2) Authorization of Related Ratemaking Principles Including Accrual of an Allowance for Funds Used During Construction; (3) Authorization to Abandon the Cunningham Unit 2 Generating Facility; and (4) Other Associated Relief, Docket No. 23-00252-UT.

[199] LNB and FGR are not technically feasible control options for CSPP's boilers for reasons described in Xcel's November 2019 FFA, while SNCR is not a technically feasible option because the exhaust temperature of the boilers is too low.

C.4.23.5 Four-Factor Analysis

In order to determine what control measures are necessary at CSPP to make reasonable progress, NMED conducted a FFA of potential control measures for NO_X for the emissions units identified in section C.4.23.2 above. States are required to consider four statutory factors – cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source – in determining reasonable progress.[200]

C.4.23.5.1 Cost of Compliance

To characterize this factor, NMED calculated the cost effectiveness, expressed in terms of cost per ton of NO_X emissions reduced, of each technically feasible control option identified in section C.4.23.4 above. NMED utilized source-specific cost estimates provided by Xcel in its calculations whenever possible. In cases where Xcel failed to provide source-specific cost estimates or NMED found estimates provided by Xcel to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs. EPA's Control Cost Manual uses real prices, not nominal prices, for estimation of capital costs and other costs. Therefore, NMED adjusted prices not already in 2024 dollars for inflation using the Chemical Engineering Plant Cost Index.[201]

NMED's cost effectiveness values for all technically feasible controls for the emissions units at CSPP are summarized below. NMED believes these values were calculated using the most representative information available and in a manner consistent with EPA-approved methodology. Detailed cost effectiveness calculations for the emissions units at CSPP and supporting documentation for NMED's cost estimates are provided in Appendix D.

Unit No.	Control Option	Total Annualized Cost (2024$)	Estimated NO_X Reductions (ton/yr)	Cost Effectiveness (2024$/ton)
1	SCR	$1,990,564	270.0	$7,000
2	SCR	$3,960,964	781.4	$5,000
3	WI	$829,976	23.9	$35,000
	SCR	$3,063,838	84.9	$36,000
	Replacement	$9,621,782	40.7	$237,000
4	WI	$829,976	32.0	$26,000
	SCR	$3,126,244	93.9	$33,000
	Replacement	$10,043,871	32.2	$312,000

NMED notes the following with respect to its determination of cost effectiveness for the technically feasible control options for the emissions units at CSPP:

- Xcel did not provide a company-specific cost of capital, so the bank prime rate (7.5 percent as of December 2024) was used to determine the appropriate capital recovery factor.

[200] CAA Section 169A(g)(1). *See also* 40 CFR 51.308(f)(2)(i).

[201] The Chemical Engineering Plant Cost Index is widely used for adjusting plant construction costs from one period to another. It is a composite index based on sub-indexes for equipment, construction labor, buildings, and engineering and supervision.

- The Total Capital Costs (TCC), Direct Annual Costs (DAC), and Indirect Annual Costs (OAC) of SCR were calculated using EPA's SCR Tool. An SCR retrofit factor of 1 (average difficulty) was applied, consistent with the SCR evaluations provided in Xcel's initial FFA.
- The Total Capital Investment (TCI) of water injection is based on a vendor estimate provided by Xcel that includes equipment, installation, labor, contingency, overhead and other capital costs. The Incremental annual O&M Costs (OMC) of water injection were also provided by Xcel.
- The TCI and OMC for replacement with new, functionally equivalent natural gas-fired units was determined using information available from the U.S. Department of Energy,[202] scaled by power rating. NMED recognizes that its OMC estimates do not account for existing O&M costs that would be displaced by replacement. However, cost effectiveness for replacement is far in excess of NMED's $10,000/ton cost effectiveness threshold based on TCI alone, so NMED did not attempt to refine its OMC estimates.

C.4.23.5.2 Compliance Time

Xcel indicated it would take 18 months to implement water injection on the CT at CSPP. NMED believes this is a reasonable timeframe.

Xcel indicated it would take 30 months to implement SCR on the CT at CSPP. This estimate is less than NMED's general assessment of compliance times and thus believed to be reasonably accurate.

Xcel did not provide information regarding the time necessary to replace the CT at CSPP with new, functionally equivalent fossil fuel-powered units. NMED believes the general compliance time for replacement, provided in Section C.3.4, is reasonable.

C.4.23.5.3 Remaining Useful Life

Consistent with generally accepted EPA methodology and NMED's experience, the useful life of SCR is estimated to be 20 years for CT and 30 years for the boilers.

Xcel indicated WI has a useful life of 15 years. This is consistent with other FFA.

Manufacturers of new CT will guarantee their equipment for at least 30 years if the unit is properly maintained and operated. Energy performance contracts for new CT are routinely 20 to 25 years, with extensions beyond 30 years. Therefore, it is estimated that the useful life of a replacement CT is 30 years.

C.4.23.5.4 Energy and Non-Air Quality Impacts

NMED's general assessment of the energy and non-air quality impacts associated with technically feasible controls for CT and boilers is provided in Sections C.3.4 and C.3.5, respectively.

[202,7] U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2023 (AEO2023) Assumptions document - Electricity Market Module

C.4.23.5.5 Summary

NMED performed a FFA for all technically feasible control options for NO_X for the units listed in Section C.4.23.2 above. The four statutory factors are discussed in Sections C.4.23.5.1 through C.4.23.5.4 and are summarized below.

Unit No.	Control Measure	Cost Effectiveness (2024$/ton)	Compliance Time (yr)	Remaining Useful Life (yr)	Significant Energy & Non-Air Quality Impacts [(1)]
1	SCR	$7,000	2.5	20	None
2	SCR	$5,000	2.5	20	None
3	WI	$35,000	1.5	15	None
	SCR	$36,000	2.5	20	None
	Replacement	$237,000	3-4	30	None
4	WI	$26,000	1.5	15	None
	SCR	$33,000	2.5	20	None
	Replacement	$312,000	3-4	30	None

[(1)] Significant energy and non-air quality impacts are those strongly influencing NMED's decision about the control measure under consideration.

C.4.23.6 Reasonable Progress Control Determinations

Cost effectiveness was the predominant factor in NMED's decision-making regarding control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations. For example, remaining useful life was used to calculate annualized costs, which in turn were used to calculate cost effectiveness, and thus was fully subsumed into the cost of compliance whereas compliance time, which is more important at the next step (determining reasonable deadlines for installing selected controls), was not a major consideration in selecting which controls are necessary to make reasonable progress in the first instance. NMED did not consider visibility impacts when making reasonable progress control determinations; EPA has consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making such determinations.[203]

As discussed in Chapter 7, Four Factor Analysis and Control Measures, NMED selected a cost effectiveness threshold of $10,000/ton for its reasonable progress control determinations based on an analysis of incremental NO_X reductions at increasing cost effectiveness levels. For emissions units with only one NO_X control below the $10,000/ton cost effectiveness threshold, NMED determined that that control is necessary to make reasonable progress. For emissions units with multiple NO_X controls below the $10,000/ton cost effectiveness threshold, NMED determined that the most stringent cost-effective control is necessary to make reasonable progress. The sole exception to these general rules is the categorical exclusion of electrification as the reasonable progress control. This exception is explained in greater detail in Chapter 7.

NMED's FFA identified cost effective controls for CSPP Units 1 and 2. Based on its analysis of the four statutory factors and the decision-making criteria described above, NMED determined that the following

[203] See *supra* note 13.

cost-effective controls are necessary to make reasonable progress **should either unit operate beyond the end of the second planning period** (if Xcel retires Units 1 and 2 on schedule, no controls are necessary to make reasonable progress):[204]

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
1	SCR	270.0
2	SCR	781.4

NMED's FFA did not identify any cost effective controls for CSPP Units 3 or 4. Therefore, NMED determined that reasonable progress does not require new controls on either of these units.

If Xcel retires Units 1 and 2 on schedule, NMED estimates the total emissions reductions at CSPP during the second planning period will be approximately 1,168.2 ton/yr of NO_X. If their retirement dates slip and both units continue to operate beyond the end of the second planning period, then based on the expected reductions from the controls NMED has determined are necessary to make reasonable progress, NMED estimates the total emissions reductions at CSPP during the second planning period will be approximately 1,051.4 ton/yr of NO_X.

[204] As noted above, the PRC recently issued an order adopting a Certification of Stipulation requiring Xcel to retire Unit 1 by 12/31/23, and another one approving Xcel's request to extend the service life of Unit 2 from 2025 to 2027 and retire it in 2027. Therefore, neither unit is expected to operate beyond the end of the second planning period.

Appendix D: Four-Factor Analyses Supporting Documentation

D.1 Davis Gas Processing

Supporting documentation for Davis Gas Processing is provided below. Facility-specific documentation is provided first, followed by documentation pertaining to multiple facilities and/or the owner/operator. The following documents are included in this section (in reading order):

- Denton Gas Plant:
    - Administrative Permit Revision (2/2/2022)
    - Permit Closure Letter (3/1/2022)

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Air Quality Bureau

Re: Permitting Administrative Multi-Form, Section 2-D
Closing a Facility
Davis Gas Processing, Inc.
Denton Gas Plant
Lovington, Lea County, NM, 87505-1816
Tempo/IDEA ID No.: 568-PRT20150001
AIRs No.: 35-025-00007

Dear Program Manager,

On behalf of Davis Gas Processing, Inc., "DGP", Environmental Operational Solutions, LLC, is submitting the attached Permitting Administrative Multi-Form for the Denton Gas Plant. Section 2-D of this form has been completed (see Attachment A) as the Denton Gas Plant was permanently shut down on December 1, 2021. The facility is being cleaned and equipment will be demoed and salvaged beginning in March of 2022. DGP is taking this action to request NMED cancel both the site's New Source Review "NSR" Construction Permit No. 0065-M8 along with this site's Title V Operating Permit No. P079-R3. Please note that DGP currently has a Title V permit renewal that was submitted to NMED on May 7, 2021, and is currently being worked by NMED permit engineer Urshula Bajracharya. This renewal project should also be cancelled.

Copies of the site's construction permit and Title V permit are included in Attachments B and C.

If you have any questions or concerns regarding this submittal, please feel free to contact me directly at (713) 983-0112 or via email at elena.hofmann@eosolutions.net.

Sincerely,

Elena L. Hofmann
President

Enclosures

cc: Mr. Alan Hill, DGP *(electronic copy only)*

Attachment A

NMED Permitting Administrative Multi-Form
Section 2-D

Permitting Administrative Multi-Form

Use for NSR administrative permit revisions (including GCPs), TV administrative amendments, TV responsible official notifications, and other submittals required by a permit condition. Refer to Section 4 for instructions, acronyms, and mailing addresses.

For Department use only:		**For Department use only:**
Reviewed by: Clayton Hengst		Received Date RECEIVED FEB 04 2022 Air Quality Bureau
Permit revision number: 0065M8RI		
Date: 25 Feb 2022		
☒ Approved ☒ Completed ☐ Denied		

Section 1: General Information – Required for All Submittals

1	Facility Name: **Denton Gas Plant**		
2	Preparer/Consultant Name: **Elena L. Hofmann**	Title: President	
3	Email: elena.hofmann@eosolutions.net	Phone: 713-983-0112	
4	Address: 13201 NW Freeway, Suite 220, Houston, TX 77040		
5	Air Permit Contact: Elena L. Hofmann	Title: President	
6	Email: elena.hofmann@eosolutions.net	Phone: 713-983-0112	
7	Address: 13201 NW Freeway, Suite 220, Houston, TX 77040		
8	Check all boxes below for which this submittal applies:	AI #: 568	Permit #: 0065M8

X NSR Construction Permit (20.2.72 NMAC) X TV Operating Permit (20.2.70 NMAC)	☐ NOI (20.2.73 NMAC) (Sections 2-B, 2-D) ☐ Notice of Exemption (20.2.72.202.B NMAC) (Section 2-F)	☐ PSD Permit (20.2.74 NMAC) ☐ Nonattainment Permit (20.2.79 NMAC)

Section 2: Details of Submittal

Only print and submit the pages necessary for your submittal. Print double sided head-to-toe, flip on short end (tablet). The Permit Section responds to all TV Administrative amendments and responds only to denials of NSR administrative revisions. Courier proof of delivery is required if you want confirmation that the Department received this submittal. Check the box(es) applicable to this submittal:

☐ 2-A(i) & 2-A(ii): Identical Engine or Turbine Replacements

☐ 2-B: Owner, Operator, and Name Changes to NOIs or Construction Permits

☐ 2-C: Ownership or Operational Control Changes for Title V Permits

☒ 2-D: Closing a Facility or Removing Units from a Permit or Canceling an NOI

☐ 2-E: Correct Typographical Error

☐ 2-F: Reporting Exempt Equipment for Minor Construction Permits or for No Permit Required (NPR) Facilities

☐ 2-G: Add Minor NSR Exempt Equipment to Construction Permits for PSD or Nonattainment Sources

☐ 2-H: Title V Responsible Official Designations

☐ 2-I: Submittals to the Permit Programs Manager

Section 3: Certification – Required for All Changes

Section 4: Form Instructions

Section 2-D: Closing a Facility, Removing Units from a Permit, or Canceling an NOI

(Administrative Revision)

Check the appropriate boxes and provide complete information in the table. Closing the permit does not relieve the permittee from any outstanding permit fees.

If any of the units being removed are emission control equipment explain how a permit, federal regulation, or state regulation will not be violated by removal of the control equipment.

☒ Cease operations of the entire facility and cancel the construction permit (20.2.72.219.A(1)(c) NMAC).

Date the facility ceased operating: December 1, 2021

☐ Retire an emissions unit and remove it from the construction permit (20.2.72.219.A(1)(c) NMAC).

Date unit(s) retired:
List all retired unit numbers to be removed from the permit:

☐ Cancel a construction permit for a facility or remove an emissions unit that has not and will not be constructed (20.2.72.219.A(1)(d) NMAC).

☐ Facility (plant) will not be constructed, or	☐ The following units will not be constructed and should be removed from the permit:

☐ Retire an emissions unit and remove it from the TV permit (20.2.70.404.A(1)(c) NMAC).

Date unit(s) retired:
List all retired unit numbers to be removed from the permit:

☐ Voluntary Discontinuation of the TV permit (20.2.70.400.I NMAC).

Date the TV permit was no longer required:
Explanation:

☐ Cancel a construction permit that is no longer required.

Explanation:

☐ Removal of minor NSR exempt equipment.

Explanation:

☐ Cancel a Notice of Intent (check one or explain):

☐ PER is now below 20.2.73.200 NMAC threshold.	☐ Date the facility ceased operating:

Section 3: Certification – Required for All Submittals

Company Name: Davis Gas Processing, Inc.

I, Richard D. Hatchett, hereby certify that the information and data submitted in this application are true and as accurate as possible, to the best of my knowledge and professional expertise and experience.

Signed this 27th day of January, 2022, upon my oath or affirmation, before a notary of the State of Texas.

R D Hatchett — 1/27/2022

Signature[1] — Date

Richard D. Hatchett — Executive Vice President

Printed Name — Title

Scribed and sworn before me on this 27th day of January, 2022.

My authorization as a notary of the State of Texas expires on the 8th day of June, 2025.

Annis Villarreal — 1/27/22

Notary's Signature — Date

Annis Villarreal

Notary's Printed Name

NOTARY PUBLIC STATE OF TEXAS
ANNIS VILLARREAL
My Notary ID # 3186019
Expires June 8, 2025

[1] For Title V applications, the signature must be of the Responsible Official as defined in 20.2.70.7.AE NMAC:

March 1, 2022

Sent by Certified Mail

David Freeman
Vice President
West Texas Gas
211 North Colorado Street
Midland, TX 79701

Ref: **Air Quality Operating Permit Application No.** P079R3M1
Denton Gas Plant
NSR Permit No. 0065M8R1
Agency Interest No. 568 - PRT20220001
AIRS No: 35-025-0007

Dear David Freeman:

The Air Quality Bureau (AQB) is in receipt of Davis Gas Processing's January 27, 2022, request to voluntarily discontinue the Denton Gas Plant Title V Operating Permit No. P079R3 pursuant to 20.2.70.400.I NMAC. On February 4, 2022, the AQB received Davis Gas Processing's request to close the New Source Review permit 0065M8 for the facility located in Lea County, New Mexico at latitude and longitude decimal degrees: 33.043869, -103.169989. In that request, the AQB was notified the plant was permanently shut down on December 1, 2021. The request to close the NSR permit was effective upon receipt per 20.2.72.219.A(3) NMAC.

With the closure of the NSR permit, the actions required to reduce the potential to emit of this facility to below Major Source thresholds have been met. Therefore, the Department has voluntarily discontinued Title V Operating Permit No. P079R3 for the Denton Gas Plant as of February 4, 2022, and this facility will be removed from the list of major Title V sources in New Mexico. Lastly, the application received May 11, 2021, for the renewal P079R4 has been identified as withdrawn.

If you have any questions, please call Clayton Hengst in Santa Fe at (505) 629-7684.

Sincerely,

Elizabeth Kuehn
Digitally signed by Elizabeth Kuehn
Date: 2022.03.01 15:24:17 -07'00'

Liz Bisbey-Kuehn
Air Quality Bureau Chief

cc via email: EPA Region VI, 6PD-R, r6airpermits@epa.gov, LeDoux.Erica@epa.gov, Layton.mary@epa.gov
NMED-AQB Compliance & Enforcement Managers via email.
Molly Greer, West Texas Gas, MGreer@westtexasgas.com

D.2 DCP Operating Company

Supporting documentation for DCP Operating Company is provided below. Facility-specific documentation is provided first, followed by documentation pertaining to multiple facilities and/or the owner/operator. The following documents are included in this section (in reading order):

- Artesia Gas Plant:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (11/2019)
    - Follow-Up Submittal (3/3/2020)
- Eunice Gas Plant:
    - Settlement Agreement and Stipulated Final Compliance Order (9/10/2021)
    - Administrative Permit Revision (11/3/2021)
    - Permit Closure Letter (11/17/2021)
- Linam Ranch Gas Plant:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (11/2019)
    - Follow-Up Submittal (3/3/2020)
    - Follow-Up Submittal (8/28/2023)
    - Follow-Up Submittal (1/23/2024)
    - Follow-Up Submittal (1/25/2024)
    - Follow-Up Submittal (2/5/2024)
- Multiple Facilities and/or Owner/Operator:
    - Four-Factor Analysis of Process and SSM Flaring (12/16/2019)

NMED Final Cost Evaluation
DCP Operating Company - Artesia Gas Plant

Facility Information

DCP - Artesia	**Facility**
ATS	**Units**
Addition of new EMD for redundant compression	**Evaluated Pollution Control**
90%	**Estimated reduction in AGI SSM/M flaring emissions**

Supporting Information

2018	**Calendar year associated with cost estimates**

Economic Evaluation

Cost Component		ATS	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 1,968,750	Targa SEP Proposal	AGI compressor, sales tax, and freight
Other Direct Capital Costs 1 ($)	ODC1	$ 1,050,000	Targa SEP Proposal	Foundations, piping, instrumentation, setting units, electrical tie-ins and expanding PDC
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	
Indirect Capital Costs ($)	IDC	$ 98,438	Targa SEP Proposal	Engineering and contingencies
Total Capital Costs - Direct ($)	TCC	$ 3,117,188	-	PEC + ODC1 + ODC2 + IDC
Additional Capital ($)	AC	$ -	-	
Total Capital Investment ($)	TCI	$ 3,117,188	-	TCC + AC
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	DCP did not provide a company-specific rate
Useful Life (yr)	Y	20	Oxy FFA	Since the unit will be operating in acid gas service, the life span of the compressor will not be longer than 20 years
Capital Recovery Factor	CRF	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 305,772	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	-	Incremental O&M reasonably negligible
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 305,772	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	90%	Oxy FFA	Estimated 90% reduction in flaring emissions; consistent with an analysis provided by Oxy for Indian Basin Gas Plant
Baseline Actual SO2 Emissions (ton/yr)	BAE	27.8	Emission Inventory	Emissions from flaring (2016-2021 average)
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by DCP
Projected Actual Emissions (ton/yr)	PAE	27.8	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	25.0	-	PAE x Eff
2018$ Cost Effectiveness ($/ton)	**CE1**	**$ 12,233**	-	TAC/ER; Targa SEP proposal is dated 12/27/18, so assume estimated costs are in 2018$
Price Index	PI	1.32	-	2024 CEPCI* / 2018 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 16,148**	-	CE1 x PI

REGIONAL HAZE FOUR-FACTOR ANALYSIS

DCP Operating Company, LP
Artesia Gas Plant

Prepared By:

Jake Zenker – Consultant
Michael Celente – Senior Consultant

TRINITY CONSULTANTS
9400 Holly Ave.
Building 3, Suite 300
Albuquerque, NM 87122
(505) 266-6611

November 2019

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1. EXECUTIVE SUMMARY

In the 1977 amendments to the Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

> *(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A).* This is known as a four-factor analysis.
>
> *(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B).* The uniform rate of progress or improvement is sometimes referred to as the glidepath and is part of the state's Long Term Strategy (LTS).

The second implementation planning period (2018-2028) for national regional haze efforts is currently underway. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural or biogenic and manmade or anthropogenic sources of emissions. Using a Photochemical Grid Model (PGM), the Western Region Air Partnership (WRAP), in coordination with the EPA, is tasked with comparing anthropogenic source contributions against natural background concentrations.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for major sources and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I area. From this analysis, 24 facilities were identified by the NMED. On July 18, 2019 the NMED informed DCP Operating Company, LP (DCP), that its Artesia Gas Plant (Artesia) was identified as one of the sources possibly contributing to regional haze at nearby Class I areas.

In coordination with guidance provided by WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. The NMED's July 18, 2019 notification letter to DCP specifies that any equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The equipment at the facility

subject to the analysis, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant are reported in Table 1.

Table 1. Summary of Equipment and Applicability to a Four-Factor Analysis

Equipment	NO_X Hourly PTE (lb/hr)	NO_X Annual PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
Emergency Wet Gas Flare (Unit 22)	642.9	7.5	No*	4918.4	49.9	No*
Emergency Acid Gas Flare (Unit 23)	10.4	2.4	No*	2001.0	328.2	No*
Malfunction Flaring (Unit M1)	642.9	10.0	No*	4918.4	10.0	No*

* Pursuant to NMED Guidance received on 9/23/2019, the Four Factor Analysis is to be completed for steady state sources of emissions only; as such, emissions from SSM/M activities are not subject to a Four Factor Analysis.

Once the applicability of process equipment and pollutants has been determined, potential retrofit control technologies must be identified. In accordance with 40 CFR 51 Appendix Y and at the recommendation of the NMED[1], this is primarily achieved by utilizing the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC).

At Artesia Gas Plant, there are potentially three (3) units which could be subject to this four-factor analysis based on SO_2 emissions (shown in Table 1). There are no units at the facility which would be subject to this analysis based on NO_X emissions. Units 22, 23 and M1 all have SO_2 emissions greater than 10 lb/hr and 5 tpy; however, these emissions are the result of either startup, shutdown, maintenance (SSM) or malfunction (M). Based on guidance received from the NMED on 9/23/2019; the four-factor analysis is to be completed for steady state sources of emissions only, which excludes emissions units associated with non-steady state/irregular emissions such as SSM/M flare sources. As such, the analysis will not be completed for any of the units at the Artesia facility.

[1] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

2. SUMMARY & CONCLUSIONS

Based on a comprehensive review of the units at Artesia, DCP has determined that due to the non-steady state nature of the emissions at this facility, i.e., intermittent nature of the emissions associated with SSM/M flaring, a four-factor analysis is not required. The costs of compliance, time necessary for compliance, energy and non-air quality environmental impacts and remaining useful life elements of a Four Factor Analysis are thus inapplicable.

3. SUPPORTING DOCUMENTATION

There is no applicable supporting documentation.

10 Desta Drive, Suite 500W
Midland, Texas 79705
Direct: 432-620-5460
Fax: 432-620-4162

March 3, 2020

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

Re: Request for additional Information on the Four-Factor Analysis Report
Regional Haze Program
Artesia Gas Plant
DCP Operating Company, LP

Mr. Singleton,

DCP Operating Company, LP (DCP) is in receipt of the New Mexico Environment Department's (NMED's) January 7, 2020, "*Request for Additional Information for Four-Factor Analyses under the Regional Haze Program*" ("Request for Additional Information" or supplemental information request), which requests various and specific supplemental information, technical discussions, analyses, and data, including possible supplemental "Four-Factor Analyses," for multiple sources with respect to DCP's Artesia natural gas processing plant in Eddy County, New Mexico. In the time afforded, and given the objections below, this letter provides DCP's responses to the January 2020 Request for Additional Information (in **blue** font, below).

NMED's January 7, 2020, Request for Additional Information, including potential Four-Factor Analyses, does not state a timeline by when the operator is to provide responsive information, and only states qualitatively to submit responses "as soon as possible." DCP notes that NMED's initial request for Four-Factor Analyses dated July 18, 2019, afforded approximately three and a half months to fulfill NMED's request for responses and analyses, requested by November 1, 2019. Given the level of information expected in NMED's initial request, DCP believes three and a half months was impracticably short, but DCP fulfilled the request to the best of the company's ability. With respect to the January 2020 Request for Additional Information, DCP received a phone call from NMED on February 10, 2020, expecting a response to the supplemental information request and possible Four-Factor Analyses by February 14, 2020, five weeks from NMED's letter of January 7, 2020. February 14, 2020, is unrealistic and unreasonable for the responses requested by NMED. DCP will provide what information it reasonably can by March 3, 2020, and will otherwise provide follow-on requested information when it is reasonable to do so given what is being requested by the agency.

As this is an administrative proceeding with an administrative record, for the record DCP must note any objections it has to the NMED request. DCP states the following objections for the record in relation to NMED's request for Regional Haze-related information and analyses, and preserves its rights related thereto notwithstanding DCP's providing information requested by NMED.

- DCP has limited resources available to respond to NMED's initial, and now supplemental information request; DCP does not have resources available to be dedicated full time to responding to NMED requests analyses, technical discussions, and responding to requests for information. DCP has expended resources, where practicable, to have third party support with respect to the company's responses to NMED's requests for assessments and information, but that support is not always practicable or available, and there are limitations on DCP's use of such third party support. DCP is providing the responses herein, to the agency's supplemental request for information, to the best of the company's ability, in the time afforded, given the limitations of its resources.

- NMED's amount of time afforded to respond to the agency's Request for Additional Information, potentially including Four-Factor Analyses, is impracticably short, unrealistic and unreasonable for a number of the requested items, and affects DCP's ability to respond to the various requests.

- DCP objects to NMED's Request for Additional Information to the extent the requests are for assessments, discussion, information, data that are not presently available and in the possession of the source, in this case DCP. It is within NMED's authority to request information presently available and in the possession of a source operator, but it is beyond the agency's authority to require a source to create or generate information or data that does not presently exist or is not in the possession of the source, or to require a source to expend monies/resources to create or generate such information or data.

- DCP objects to vague, ambiguous or undefined terms in the Request for Additional Information, and objects to the extent the request require DCP to engage in speculation in order to attempt to respond to an agency's stated question or request.

- DCP objects NMED's requests for assessments or analyses that directly or indirectly result in or would relate to "redefining the source," being a properly-authorized, operating, and permitted emissions source. The federal Regional Haze regulation contemplates emissions control technologies that might be cost-effectively retrofitted on a source; redefining a properly-authorized, permitted and operating source is not a retrofit control technology, and is beyond the authority of the Regional Haze rule to consider as a Reasonable Progress measure.

- DCP objects to the fact that NMED has not provided, as part of this administrative process, the cost-effectiveness threshold for control technologies for the Regional Haze Reasonable Progress rulemaking.

- DCP objects to the agency's fundamental threshold for requesting 4-Factor Analyses from sources in the State, *i.e*., Q/d of 5, as this is unreasonably stringent and requiring resource expenditures for assessments of sources that would not effectively contribute to visibility improvement in Class I areas. The State of Colorado applied a Q/d of 20 as its screening criteria, which assumed an estimated associated deciview improvement of 0.3; a Q/d of 5 would provide, presumably, one-quarter of the assumed visibility improvement, so requiring screening of sources at that level that would provide potentially, *e.g*., 0.07 deciview improvement.

Preserving the objections noted, above, DCP responds to the agency's January 7, 2020, Request for Additional Information as follows (NMED Jan. 7, 2020, requests re-stated in black font, and DCP responses provided in blue font).

a. Provide a description of each flare, the design and type, and its purpose.

Unit No. SSM (22), Emergency Wet Gas Flare, serves as both emergency/SSM flare and a process flare to Artesia's wet gas service. The Emergency wet gas flare will flare pilot, purge, and blanket gas from TK-C (condensate storage tank) during steady state operations and any gas flow to the flare that results from startup, shutdown, maintenance, malfunction (SSM&M) and other emergency events.

Unit No. SSM (23), Acid Gas Flare, serves as emergency/SSM&M flare to Artesia's acid gas service. The Acid gas flare will flare pilot, purge, assist gas and any acid gas flow to the flare that results from SSM&M and emergency events.

Please reference *Attachment A – Flare Emission Calculation*.

b. List and describe the reasons that trigger each type of flaring event.

Steady state emission from the Emergency Wet Gas Flare and Acid Gas Flare are represented in the *Attachment A – Flare Emission Calculation*.

Other flaring events include permit authorized planned SSM flaring events and unplanned flaring events. Planned SSM emission flaring events are triggered by routine maintenance at frequency recommended by the manufacturer. Allowable emission limit as included in the facility's air permit represent maximum amount of emission that can occur during all planned maintenance activities and startup/shutdown events that is anticipated pre and post-maintenance. However, these planned maintenance events do not occur at the same frequency, i.e. quarterly, annual, biennial, every five year and etc, therefore, actual emission that occur at the facility differs each year as represented in DCP's process and SSM flaring four factor analysis report submitted on December 16, 2019.

Unplanned flaring events are triggered through various unforeseeable reasons such as equipment malfunction, power loss, and etc. Excess emission resulting from these event are reported to NMED pursuant to NMAC 20.2.7.110. DCP operates emission equipment in a manner consistent with good air pollutant control practices for minimizing emission.

c. Discuss potential alternative control options or operational changes that could reduce NO_X and/or SO_2 flaring emissions, including:

i. infrastructure that allows re-routing or recirculating the gas within the facility or outside of the facility until an SSM event is over;

Artesia's current infrastructure supports nat. gas re-routing, and off-loading when feasible under certain circumstances, each of which serve to reduce flaring emissions. Artesia has the ability, when necessary, to close the nat. gas inlet to the facility, which significantly limits or prevents flaring at the facility. Artesia also coordinates with the producers, either prior to a planned event, or when feasible during an unplanned event, to temporarily re-route nat. gas to other facilities if practicable or to shut in nat. gas for a finite period, to reduce the volume of nat. gas potentially subjected to flaring at the facility. Under certain circumstances DCP can, and does, utilize producer temporary off-load capabilities, or DCP capability to temporarily re-route gas when practicable and feasible, to minimize the volume of nat. gas potentially subjected to flaring at the facility. DCP believes that these capabilities and measures, taken together, serve to prevent flaring at the Artesia facility or to mitigate the duration of a flaring event or the volume

of material subjected to flaring. DCP is not aware of another technically feasible option to appreciably further reduce flaring events or volumes at the facility.

ii. sulfur absorbent technology used to remove sulfur from pipelines and other auxiliary equipment to reduce inlet or plant flaring SO_2 emissions;

The Artesia nat. gas processing plant receives, and is designed to receive, high hydrogen sulfide ("H2S") concentration natural gas, referred to as "sour" nat. gas. Given the high H2S concentration received by the Artesia plant, an amine treatment system is the most effective and the only technology that is technically feasible to remove sulfur and treat the sour gas stream of this volume and concentration.

Other sulfur absorbent technology, such as pipeline additive injection, commonly referred to as hydrogen sulfide scavenger, is utilized only non-sour gas systems, meaning on what are known as "sweet" gas streams, in order to treat very small amounts of hydrogen sulfide that might exist in a sweet gas stream to meet a certain specification, and are not suitable or effective for treating the sour gas stream processed at Artesia Plant; they would not meaningfully reduce the concentration of H2S that would recognizably affect the amount of sulfur received by the Artesia plant.

iii. Gas Capture Plans with facilities located downstream and upstream similar to those required for producers to better synchronize upstream and downstream services with the facility;

DCP objects to the use of an ambiguous or undefined term with respect to a midstream nat. gas processing plant facility, and to the extent this question requires speculation. A Gas Capture Plan is a New Mexico Oil Conservation Division ("NMOCD") requirement for producer entities, for the producer's production development, to ensure communication between the producer entity and gatherer in order to improve communication and planning future nat. gas takeaway capacity, in order to mitigate the potential for a producer entity having to flare what would be stranded gas at its well production facility if there weren't nat. gas takeaway. DCP as a midstream entity does confer with producers about the producer's Gas Capture Plans. The concept, however, has no applicability to a midstream nat. gas processing plant as such a facility, for example the Artesia plant, is by definition designed to receive and process the producer's nat. gas; DCP's Artesia gas plant does not flare nat. gas due to lacking capacity, for example, so the concept is not applicable to a midstream gas processing plant.

iv. use of remote capture equipment;

DCP objects to the use of an ambiguous or undefined term with respect to a midstream nat. gas processing plant facility, and to the extent this question requires speculation. Remote capture equipment, as DCP understands it from NM agency materials, is a concept that relates to and provides capability at a producer wellhead and relates to wellhead volumes of nat. gas and nat. gas products (liquids) at the producer wellhead. The same concept does not have applicability to a midstream nat. gas processing facility, and the type of technology is not applicable at the scale of a nat. gas processing facility; a midstream nat. gas processing plant, by definition, is removing nat. gas products (liquids) from the inlet material, which is one of its functions.

v. better infrastructure planning and changes to existing infrastructure that connects the downstream and upstream operations to DCP facilities to ensure that there is adequate processing capacity to move produced gas to market.

DCP objects to the use of ambiguous or undefined terms, and to the extent this question requires speculation. As described in the prior responses, DCP's Artesia nat. gas plant processing capacity appropriately and adequately manages relevant producer nat. gas production; the plant does not flare nat. gas due to lacking capacity.

Note that flaring at an up or downstream facility to avoid flaring at the Artesia Gas Plant is not considered to be an actual reduction in flared emissions rates under the four-factor analysis.

d. For any technically feasible solutions, provide a four-factor analysis. For additional information regarding potential alternative controls to flaring see the New Mexico Methane Strategy website: https://www.env.nm.gov/new-mexico-methane-strategy/methane-advisory-panel/.

Considering the above requests, DCP is not aware of any additional flaring technology or relevant operational changes that are technically feasible.

e. Please explain the discrepancy between the SSM SO_2 emissions provided in the supplemental flaring analysis (0.0 tons) and NMED's 2016 inventory (17.96 tons).

The referenced SSM SO2 emission amount only refers to authorized emission and does not include excess emission resulting from unforeseeable events. Table 2 of the December 16, 2019 submitted response is titled "Artesia 2016 EIQ Reported **Process** Flaring and **SSM** Flaring Emission".

If you have any questions or concerns, please feel free to contact me directly by phone at 432-215-8514 or via email at hshong@dcpmidstream.com.

Sincerely,

Sam Hong
Environmental Engineer
DCP Midstream, LP

Enclosures

Attachment A – Flare Emission Calculation

DCP Midstream, LP - Artesia Gas Plant

Emergency Wet Gas Flare

Emission Unit: 22

Estimated Flared Gas Composition Used for Calculations

Component	MW	Flared Gas[1] Mol%	MW * wet vol %	HHV Btu/scf[2]	Btu/scf * wet vol %	Mass Fraction (wet)	Spec. Volume[2] ft^3/lb	Spec. Volume VOC ft^3/lb
Water	18.02	0.0000%	0.00	0.0	0.0	0.00	21.06	
Hydrogen Sulfide	34.08	0.4144%	0.14	637.02	2.6	0.01	11.136	
Carbon Dioxide	44.01	1.0534%	0.46	0.0	0.0	0.02	8.623	
Nitrogen	28.01	1.7683%	0.50	0.0	0.0	0.02	13.547	
Oxygen	32.00	0.0000%	0.00	0.0	0.0	0.00	13.5	
Methane	16.04	71.6031%	11.49	1009.7	723.0	0.49	23.65	
Ethane	30.07	12.2486%	3.68	1768.7	216.6	0.16	12.62	
Propane	44.10	6.6464%	2.93	2517.2	167.3	0.12	8.606	3.514
i-Butane	58.12	0.9775%	0.57	3252.6	31.8	0.02	6.529	0.517
n-Butane	58.12	2.4062%	1.40	3262	78.5	0.06	6.529	1.272
i-Pentane	72.15	0.7272%	0.52	4007.7	29.1	0.02	4.26	0.311
Pentanes	72.15	0.7169%	0.52	4008.7	28.7	0.02	5.26	0.379
Hexanes+	86.18	1.4380%	1.24	4756.1	68.4	0.05	4.404	0.760
		100%	23.45		1346.1	1.00		6.753
NMNEHC (VOC)		12.9%				30.6%		

[1] *Based on Analysis 07/1/2012, ARTESIA PLT 5# FLARE, unit 22. to provide conservative estimates for sulfur dioxide and heat release estimate.*

[2] *Component HHVs and specific volumes obtained from Physical Properties of Hydrocarbons, API Research Project 44, Fig. 16-1, Rev. 1981.*

Fuel Data

Flare Pilot	500	scf/hr	Design
	0.0005	MMscf/hr	
	1008.00	Btu/scf	Pipeline Gas, HHV
	0.50	MMBtu/hr	MMscf/hr * Btu/scf
Purge Gas	25.80	Mscf/day	Design
	1.075	Mscf/hr	Mscf/d / 24 hr/day
	0.001075	MMscf/hr	Mscf/hr / 1000
	1000.00	Btu/scf	Pipeline Gas, HHV
	1.08	MMBtu/hr	MMscf/hr * Btu/scf
TK-C Blanket Gas	1.50	Mscf/day	Design
	0.0625	Mscf/hr	Mscf/d / 24 hr/day
	0.0000625	MMscf/hr	Mscf/hr / 1000
	1000.00	Btu/scf	Pipeline Gas, HHV
	0.06	MMBtu/hr	MMscf/hr * Btu/scf
Flared Gas - Short Term	7.0	MMscf/hr	Effective hourly flowrate
	1,346	Btu/scf	Heating value calculated from gas compostion above.
	9,452	MMBtu/hr	Hourly heat rate = Heating value * Effective hourly flow rate.
Flared Gas - Annual	142.1	MMscf/yr	Estimated Maximum annual SSM flow rate. Not a requested limit; for calculation only.
Total	9453.3	MMBtu/hr	**Pilot + Purge gas + TK-C Blanket Gas + Flared gas**

Stack Parameters

	1000	˚C	Exhaust temperature	Per NMAQB guidelines
	20	m/sec	Exhaust velocity	Per NMAQB guidelines
	70.6	ft	Flare height	
Pilot + Purge Gas + TK-C Blanket Gas				
	16.04	g/mol	Pilot & Purge gas molecular weight	Mol. wt. of methane, the dominant species
	114,905	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
	92,816		q_n	$q_n = q(1\text{-}0.048(MW)^{1/2})$
	0.3047	m	Effective stack diameter (D)	$D = (10^{-6}q_n)^{1/2}$
Pilot + Purge Gas + TK-C Blanket Gas				
	23.45	g/mol	Flared gas molecular weight	Volume weighted mol. wt. of all components
	6.62E+08	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
	5.08E+08		q_n	$q_n = q(1\text{-}0.048(MW)^{1/2})$
	22.5373	m	Effective stack diameter (D)	$D = (10^{-6}q_n)^{1/2}$

DCP Midstream, LP - Artesia Gas Plant

Emergency Wet Gas Flare

Emission Unit: 22

Emission Rates

Pilot + Purge Gas + TK-C Blanket Gas

NOx	CO	VOC	H_2S	SO_2	Units	
0.0680	0.3700				lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
			4E-04		lb H_2S/Mscf	Purchased sweet natural gas fuel, 0.25 gr H_2S/100scf
			5.85E-04		lb H_2S/hr	H_2S rate * fuel usage
				7E-03	lb S/Mscf	Purchased sweet natural gas fuel, 5 gr S/100scf
				1E-02	lb SO_2/hr*	SO_2 rate * fuel usage
		0.00%			mol%	Assume no VOC content in purchased fuel (methane)
		23.7			ft^3/lb	Specific volume (methane)
		0.00			lb/hr	vol. Gas * mole fraction / specific volume
100%	100%	100%	100%	100%	%	Safety Factor
0.1360	0.7400				lb/MMBtu	Unit emission rate with Safety Factor
0.223	**1.215**				lb/hr	lb/MMBtu * MMBtu/hr
		0.00	**2.3E-05**	**0.023**	lb/hr	98% combustion H_2S; 100% conversion to SO_2
0.98	**5.32**	**0.00**	**1.0E-04**	**0.10**	tpy	8760 hrs/yr

Flared Gas

NOx	CO	VOC	H_2S	SO_2	Units	
0.0680	0.3700				lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
		12.91%	0.41%		mol%	Flare Gas
		6.753	11.136		ft^3/lb	Specific volume
		134,257.2	2,612.9		lb/hr	vol. Gas * mole fraction / specific volume
642.72	3497.13				lb/hr	lb/MMBtu * MMBtu/hr
642.72	3497.13	134,257.2	2,612.9	4918.3	lb/hr	Uncontrolled emissions
6.50	35.38	1,358.2	26.4	49.8	tpy	at maximum rate

Unit 22 - Emergency Wet Gas Flare	NOx	CO	VOC	H_2S	SO_2	HAPs	Units
Pilot + Purge + TK-C Blanket Gas	**642.9**	**3498.3**	**2685.1**	**52.3**	**4918.4**	**38.6**	lb/hr
+ Flared Gas	**7.5**	**40.7**	**27.2**	**0.53**	**49.9**	**0.39**	tpy

GHG Emissions

	CO_2e Short Tons/yr		
CO_2	11,536.2	Eq 4-15	API Compendium
CH_4	10.7	Eq 4-16	API Compendium
N_2O	0.00023	Eq 4-17	API Compendium
Total CO2e	**11,804**		

DCP Midstream, LP - Artesia Gas Plant

Emergency Acid Gas Flare

Emission Unit: 23

Estimated Flared Gas Composition Used for Calculations

Component	MW	Flared Gas[1] Mol%	MW * wet vol %	HHV Btu/scf[2]	Btu/scf * wet vol %	Mass Fraction (wet)	Spec. Volume[2] ft³/lb	Spec. Volume VOC ft³/lb
Water	18.02	0.0000%	0.00	0.0	0.0	0.00	21.06	
Hydrogen Sulfide	34.08	37.0907%	12.64	637.02	236.3	0.31	11.136	
Carbon Dioxide	44.01	62.5070%	27.51	0.0	0.0	0.68	8.623	
Nitrogen	28.01	0.0315%	0.01	0.0	0.0	0.00	13.547	
Oxygen	32.00	0.0000%	0.00	0.0	0.0	0.00	13.5	
Methane	16.04	0.3439%	0.06	1009.7	3.5	0.00	23.65	
Ethane	30.07	0.0227%	0.01	1768.7	0.4	0.00	12.62	
Propane	44.10	0.0006%	0.00	2517.2	0.0	0.00	8.606	0.766
i-Butane	58.12	0.0013%	0.00	3252.6	0.0	0.00	6.529	1.659
n-Butane	58.12	0.0001%	0.00	3262	0.0	0.00	6.529	0.128
i-Pentane	72.15	0.0000%	0.00	4007.7	0.0	0.00	4.26	0.000
Pentanes	72.15	0.0000%	0.00	4008.7	0.0	0.00	5.26	0.000
Hexanes+	86.18	0.0022%	0.00	4756.1	0.1	0.00	4.404	2.807
		100%	40.22		240.3	1.00		5.359
NMNEHC (VOC)		0.004%				0.0%		

[1] *1 Based on Analysis 07/1/2012, ARTESIA ACID GAS FLARE, unit 23.*

[2] *Component HHVs and specific volumes obtained from Physical Properties of Hydrocarbons, API Research Project 44, Fig. 16-1, Rev. 1981.*

Fuel Data

Flare Pilot	500	scf/hr	Design
	0.0005	MMscf/hr	
	1008.00	Btu/scf	Pipeline Gas, HHV
	0.50	MMBtu/hr	
Purge Gas	3.10	Mscf/day	Design
	0.129	Mscf/hr	Mscf/d / 24 hr/day
	1.29E-04	MMscf/hr	Mscf/hr / 1000
	1008.00	Btu/scf	Pipeline Gas, HHV
	0.13	MMBtu/hr	MMscf/hr * Btu/scf
Assist Gas			
	255.2	Btu/scf	Heating value of Pilot + Purge gas + Flared gas
	865.0	Btu/scf	target heat content
	1,000.0	Btu/scf	Assist gas-assumed sweet
	0.14	MMscf/hr	Assist gas volume
	144.1	MMBtu/hr	Assist gas heat input
*Assist gas - Annual**	57.7	MMscf/yr	Estimated Maximum annual SSM flow rate. Not a requested limit; for calculation only.
Note:	Flared gas annual/ ratio of assist gas: flared gas hourly usa ex: 10.5 MMscf/yr / (1-.8054)		
Flared Gas - Short Term	0.032	MMscf/hr	Effective hourly flowrate
	240	Btu/scf	Heating value calculated from gas compostion above.
	8	MMBtu/hr	Hourly heat rate = Heating value * Effective hourly flow rate.
Flared Gas - Annual	10.5	MMscf/yr	Estimated Maximum annual SSM flow rate. Not a requested limit; for calculation only.
Total	**152.4**	**MMBtu/hr**	**Pilot + Purge gas + Flared gas + Assist gas**

Stack Parameters

	1000	˚C	Exhaust temperature	Per NMAQB guidelines
	20	m/sec	Exhaust velocity	Per NMAQB guidelines
	70.6	ft	Flare height	
Pilot+ Purge Gas only				
	16.04	g/mol	Pilot & Purge gas molecular weight	Mol. wt. of methane, the dominant species
	44,394	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
	35,860		q_n	$q_n = q(1\text{-}0.048(MW)^{1/2})$
	0.1894	m	Effective stack diameter (D)	$D = (10^{-6}q_n)^{1/2}$
Flared Gas MW				
	40.22	g/mol	MW flare gas	
	16.04	g/mol	MW assist gas, flare gas, purge gas	
	0.03	MMscf/hr	vol flare gas	
	0.14	MMscf/hr	vol assist gas	
	0.00063	MMscf/hr	vol pilot + purge gas	
	7.26	g/mol	vol. weighted % flare gas	
	13.09	g/mol	vol. weighted % assist gas	
	0.06	g/mol	vol. weighted % pilot + purge gas	
Pilot+Flared Gas+ Assist gas	20.41	g/mol	weighted-averaged Flared gas molecular weight	Volume weighted mol. wt. of all components
	1.07E+07	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
	8.35E+06		q_n	$q_n = q(1\text{-}0.048(MW)^{1/2})$
	2.8905	m	Effective stack diameter (D)	$D = (10^{-6}q_n)^{1/2}$

DCP Midstream, LP - Artesia Gas Plant

Emergency Acid Gas Flare

Emission Unit: 23

Emission Rates

Pilot+ Purge Gas

	NOx	CO	VOC	H_2S	SO_2	Units	
	0.0680	0.3700				lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
				4E-04		lb H_2S/Mscf	Purchased sweet natural gas fuel, 0.25 gr H_2S/100scf
				2.25E-04		lb H_2S/hr	H_2S rate * fuel usage
					7E-03	lb S/Mscf	Purchased sweet natural gas fuel, 5 gr S/100scf
					4E-03	lb SO_2/hr	SO_2 rate * fuel usage
			0.00%			mol%	Assume no VOC content in purchased fuel (methane)
			23.7			ft^3/lb	Specific volume (methane)
			0.00			lb/hr	vol. Gas * mole fraction / specific volume
	100%	100%	100%	100%	100%	%	Safety Factor
	0.1360	0.7400				lb/MMBtu	Unit emission rate with Safety Factor
	0.086	**0.469**				lb/hr	lb/MMBtu * MMBtu/hr
			0.000	**9.0E-06**	**9.0E-03**	lb/hr	98% combustion H_2S; 100% conversion to SO_2
	0.38	**2.06**	**0.000**	**3.9E-05**	**4.0E-02**	tpy	8760 hrs/yr

Assist gas

	NOx	CO	VOC	H_2S	SO_2	Units	
	0.0680	0.3700				lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
				4E-04		lb H_2S/Mscf	Purchased sweet natural gas fuel, 0.25 gr H_2S/100scf
				5.15E-02		lb H_2S/hr	H_2S rate * fuel usage
					7E-03	lb S/Mscf	Purchased sweet natural gas fuel, 5 gr S/100scf
					1E+00	lb SO_2/hr	SO_2 rate * fuel usage
			0.00%			mol%	Assume no VOC content in purchased fuel (methane)
			23.7			ft^3/lb	Specific volume (methane)
			0.00			lb/hr	vol. Gas * mole fraction / specific volume
	9.799	**53.318**				lb/hr	lb/MMBtu * MMBtu/hr
			0.000	**1.0E-03**	**1.0E+00**	lb/hr	98% combustion H_2S; 100% conversion to SO_2
	1.96	**10.68**	**0.000**	**2.06E-04**	**0.21**	tpy	

Flared Gas

	NOx	CO	VOC	H_2S	SO_2	Units	
	0.0680	0.3700				lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
			0.004%	37.09%		mol%	Flare Gas
55			5.359	11.136		ft^3/lb	Specific volume
			0.3	1,062.5		lb/hr	vol. Gas * mole fraction / specific volume
	0.52	2.84				lb/hr	lb/MMBtu * MMBtu/hr
	0.52	**2.84**	**0.3**	**21.2**	**2,000.0**	**lb/hr**	98% combustion H_2S; 100% conversion to SO_2
	0.09	**0.47**	**0.04**	**3.5**	**328.0**	**tpy**	

Acid Gas Flare	**NOx**	**CO**	**VOC**	**H_2S**	**SO_2**	**Units**
pilot + flared gas+Assist Gas	**10.4**	**56.6**	**0.005**	**21.3**	**2001.0**	lb/hr
	2.4	**13.2**	**0.00082**	**3.5**	**328.2**	tpy

GHG Emissions

	CO_2e Short Tons/yr		
CO_2	382	Eq 4-15	API Compendium
CH_4	3.8E-03	Eq 4-16	API Compendium
N_2O	1.7E-05	Eq 4-17	API Compendium
Total CO2e	**381.9**		

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STATE OF NEW MEXICO
SECRETARY OF ENVIRONMENT

ENVIRONMENTAL PROTECTION DIVISION
OF THE NEW MEXICO ENVIRONMENT DEPARTMENT,

Complainant,

No. AQB 20-46 (CO)

DCP OPERATING COMPANY, LP

Respondent.

and

ENVIRONMENTAL PROTECTION DIVISION
OF THE NEW MEXICO ENVIRONMENT DEPARTMENT,

Complainant,

No. AQB 20-64 (CO)

DCP OPERATING COMPANY, LP

Respondent.

SETTLEMENT AGREEMENT AND STIPULATED FINAL COMPLIANCE ORDER

This Settlement Agreement and Stipulated Final Compliance Order ("Final Order") is entered into between the Environmental Protection Division ("Division") of the New Mexico Environment Department ("Department" or "NMED") and Respondent, DCP Operating Company, LP and relevant affiliates thereof, ("DCP") (collectively, the "Parties") to resolve alleged statutory, regulatory, and permit violations by DCP. The Department alleges violations of the New Mexico Air Quality Control Act ("AQCA"), NMSA 1978, Sections 74-2-1 to -17; the Air Quality Control Regulations ("Regulations") at Title 20, Chapter 2 NMAC, and various Air Quality Permits ("Permits") as identified below.

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I. BACKGROUND

A. PARTIES

1. The Division is an organizational unit of the Department and has been delegated the authority by the Secretary of the Department to issue compliance orders under the AQCA. NMSA 1978, § 74-2-12.A (2006). The Air Quality Bureau ("Bureau") is an organizational unit of the Division.

2. DCP is a limited partnership doing business in New Mexico at the following facilities: Burton Flats Compressor Station, Fitz Compressor Station, Lovington Booster Station, Lynch Booster Station, Monument Booster Station, Sand Dunes Compressor Station, South Hat Compressor Station, West Turkey Track Compressor Station, Artesia Gas Plant, Eunice Gas Plant, Linam Ranch Gas Plant and Zia II Gas Plant (collectively, the "Facilities"). DCP owns and operates the Facilities, located in Lea and Eddy Counties, New Mexico. At all times relevant to this Final Order, DCP owned and operated the Facilities.

B. HISTORY AND ALLEGED VIOLATIONS

The alleged violations are set forth in the two Compliance Orders and are summarized below.

Burton Flats Compressor Station

3. Since April 15, 2014, Burton Flats has been authorized to operate under NSR Permit 0612-M5.

4. The following table from NSR permit 0612-M5, Condition A106 lists the Facility emission units and their allowable emission limits. *See* 40 CFR Part 50; 40 CFR Part 60, Subparts A and JJJJ; 40 CFR Part 63, Subparts A and ZZZZ; 20.2.72.210.A and B(1) NMAC.

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Table 1: Burton Flats, Table 106.A, Allowable Emissions

Unit No.	NO_x[1] (pph)	NO_x[1] (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)
1	2.8	12.2	2.8	12.2	1.4	6.1
2	2.8	12.2	2.8	12.2	1.4	6.1
3	2.8	12.2	2.8	12.2	1.4	6.1
4	2.8	12.2	2.8	12.2	1.4	6.1
5	2.8	12.2	2.8	12.2	1.4	6.1
6	2.8	12.2	2.8	12.2	1.4	6.1
7	3.6	15.8	3.6	15.8	1.8	7.9
TK-1[4]	- [2]	-	-	-	*[3]	4.9
TK-2	-	-	-	-	*	4.9
LOAD	-	-	-	-	*	0.87

1 Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2
2 Total Particulate matter (TSP) is estimated to equal PM10 and PM2.5. These emissions include condensable PM emissions.
3 For Title V facilities, the Title V annual fee assessments are based on the sum of allowable tons per year emission limits in Sections A106 and A107.
4 F-100R represents routine flaring from tank flash, amine, pilot, dehydrator.

5. The following table from NSR Permit 0612 M5, Condition A.107 - "Facility: Allowable Startup, Shutdown, and Maintenance and Malfunction Emissions," lists the facility-wide startup, shutdown, maintenance ("SSM"), and malfunction emission limits:

Table 2: Burton Flats, Table 107.A, Allowable SSM & M Units, Activities, and Emission Limits

Unit No.	Description	VOC (tpy)
SSM Facility Wide	Compressor & Associated Piping Blowdowns during Routine and Predictable Startup, Shutdown, Maintenance (SSM), and/or Malfunctions	10

(This authorization does not include VOC combustion emissions.)

6. Between December 29, 2017 and June 30, 2019, DCP reported ten (10) excess emission events and asserted affirmative defenses as provided in 20.2.7 NMAC.

7. The Bureau issued Notice of Violation ("NOV") DCP-0251-1801 for four of these alleged violations on December 7, 2018.

8. The Division alleges that DCP violated NSR permits 0612-M5, Condition A106.A and A107.A, by exceeding the permitted allowable emission limits of the emergency blowdown

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vent during ten (10) excess emission events. These events resulted in a total of eighty-nine (89) alleged violations ("Burton Flats Violations").

9. The Division alleges that the Burton Flats Violations resulted in the unlawful emission of 63,437 pounds of volatile organic compounds ("VOC") and hydrogen sulfide ("H_2S")

10. The Division maintains that DCP's reported excess emission events at Burton Flats Compressor Station do not qualify for affirmative defenses under the New Mexico Air Quality Control Act and the NMED Air Quality Bureau Civil Penalty Policy and are therefore subject to penalties. DCP maintains that its affirmative defense claims are valid.

Fitz Compressor Station

11. Between June 21, 2012 and October 3, 2019, the Fitz Compressor Station was authorized to operate under NSR permit 0832-M2. Since October 4, 2019, the Fitz Compressor Station has been authorized to operate under GCP-O&G Permit number 0832-M3.

12. The following table from NSR Permit 0832-M2, Condition A.106 – "Facility: Allowable Emissions," lists the emission units and their allowable emission limits. *See* 40 CFR Part 50; 40 CFR Part 63, Subparts A and ZZZZ; and 20.2.72.210.A and B(1) NMAC:

Table 3: Fitz, Table 106.A, Allowable Emissions

Unit No.	NO_x[1] (pph)	NO_x[1] (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)	SO_2 (tpy)
1	4.2	18.5	5.0	21.9	< [3]	2.5	1.1
2	4.2	18.5	5.0	21.9	< [3]	2.5	1.1
3	4.2	18.5	5.0	21.9	< [3]	2.5	1.1
4	4.2	18.5	5.0	21.9	< [3]	2.5	1.1
TK-1	- [2]	- [2]	- [2]	- [2]	* [5]	9.9	- [2]
L-1	- [2]	- [2]	- [2]	- [2]	* [5]	2.5	- [2]
Total[4]	16.8	74.0	20.0	87.6	4.7	23.0	4.4

1 Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2
2 "–" indicates the application represented emissions of this pollutant are not expected
3 "<" indicates the application represented uncontrolled emissions are less than 1.0 pph or 1.0 tpy for this pollutant. Allowable limits are not imposed on this level of emissions, except for flares and pollutants with controls.
4 Total allowables are for information and are not enforceable conditions
5 "*" indicates hourly emission limits are not appropriate for this operating situation

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13. The following table from NSR Permit 0832-M2, Condition A.107 – "Facility: Allowable Startup, Shutdown, & Maintenance and Malfunction Emissions," lists the facility-wide SSM and malfunction emission limits:

Table 4: Fitz, Table 107.A, Allowable SSM and Malfunction Units, Activities and Emission Limit

Unit No.	Description	VOC (tpy)
SSM and Malfunction from facility	Includes, but is not limited to, engine startup compressor and associated piping blowdowns and venting of gas due to malfunction	10
	Total[1]	10

[1] Totals are for information only, not enforceable conditions
(This authorization does not include VOC combustion emissions)

14. The following table from NSR Permit 0832-M3, Oil and Gas GCP Application Table 2B: "Allowable Emission Limits," (beginning October 4, 2019) lists the maximum allowable unit and facility-wide SSM and malfunction emission limits:

Table 5: Fitz, Table 2B, Allowable Emission Limits

Unit No.	NO_x[1] (pph)	NO_x[1] (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)	SO_2 (pph)	SO_2 (tpy)	H_2S (pph)	H_2S (tpy)
1	1.76	7.7	1.76	7.7	0.91	3.96	0.07	0.31	-	-
2	1.76	7.7	1.76	7.7	0.91	3.96	0.07	0.31	-	-
3	1.76	7.7	1.76	7.7	0.91	3.96	0.07	0.31	-	-
4	1.76	7.7	1.76	7.7	0.91	3.96	0.07	0.31	-	-
5	1.9	8.33	0.34	1.5	1.09	4.75	0.14	0.62	-	-
6	1.9	8.33	0.34	1.5	1.09	4.75	0.14	0.62	-	-
TK-1	-	-	-	-	0.11	0.5	-	-	-	-
TK-2	-	-	-	-	0.11	0.5	-	-	-	-
L-1	-	-	-	-	62.71	1.53	-	-	-	-
FUG-1	-	-	-	-	1.54	6.72	-	-	<0.01	<0.01
SSM/M	-	-	-	-	-	30	-	-	-	-

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15. Between January 1, 2018 and June 30, 2019, DCP reported eighty-six (86)[1] excess emission events and asserted affirmative defenses as provided in 20.2.7 NMAC.

16. The Bureau issued two NOVs for fifty-one of these alleged violations: DCP-0263-1801 on December 14, 2018, and DCP-0263-1802 on March 18, 2019.

17. The Division alleges that DCP violated NSR Permit 0832-M2, Conditions A106.A and A107.A and NSR Permit 0832-M3, Oil and Gas GCP Application Table 2B, by venting emissions in excess of the permitted allowable emission limits for the vent during eighty-six (86) excess emission events. These events resulted in a total of one thousand one hundred and eighty (1,180) alleged violations ("Fitz Violations").

18. The Division alleges that the Fitz Violations resulted in the unlawful emission of 822,823.15 pounds of VOC and H_2S.

19. The Division maintains that the Fitz Violations do not qualify for affirmative defenses under the Act or the Penalty Policy, and DCP is therefore subject to penalties for those violations. DCP maintains that its affirmative defense claims are valid.

Lovington Booster Station

20. Between June 2, 2006 and April 23, 2019, the Lovington Booster Station was authorized to operate under NSR Permit 0423-M7.

21. The following table from NSR Permit 0423-M7, "Table 2.1, Allowable Emissions," lists the emission units and their allowable emission limits. Malfunction and SSM emissions are not listed separately.

[1] Revised Compliance Order No. AQB-20-46 stated that 51 excess emission events were reported and included in the two NOVs, and an additional 45 excess emission events were reported and not included in NOVs. DCP's Answer identified that ten of the additional 45 events were included in one of the NOVs, resulting in 35 excess emission reports not included in the two NOVs.

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Table 6: Lovington, Table 2.1, Allowable Emissions

Unit No.	PM_{10} (pph)	PM_{10} (tpy)	SO_2 (pph)	SO_2 (tpy)	NO_x[1] (pph)	NO_x[1] (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)	H_2S (pph)	H_2S (tpy)
1	-[2]	-	-	-	5.3	23.2	5.3	23.2	1.8	7.7	-	-
2	-	-	-	-	5.3	23.2	5.3	23.2	1.8	7.7	-	-
3	-	-	-	-	9.8	42.8	9.8	42.8	3.3	14.3	-	-
4	-	-	-	-	5.9	25.9	8.9	38.8	3.0	12.9	-	-
L-1	-	-	-	-	-	-	-	-	--[3]	0.5	-	-
Flare			3226.4	96.8	37.6	1.2	204.4	6.4	510.5	15.4	35.1	1.1
TK-5	-	-	-	-	-	-	-	-	3.8	16.5	-	-

1 Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO2
2 "-" indicates that in accordance with the application, no emissions of this pollutant are expected
3 "- -" indicates that emissions are less than 0.5 pph or 0.5 tpy and emission limits are not required for this permit

22. Between November 27, 2018 and April 26, 2019, DCP reported ten (10) excess emission events and asserted affirmative defenses as provided by 20.2.7 NMAC.

23. The Division alleges that DCP violated NSR Permit 0423-M7, Table 2.1, by flaring emissions from the unit Flare in excess of its permitted allowable emission limits during ten (10) excess emission events. These events resulted in a total of one hundred and sixty (160) alleged violations ("Lovington Violations").

24. The Division alleges that the Lovington Violations resulted in the unlawful emission of 21,499.33 pounds of carbon monoxide ("CO"), sulfur dioxide ("SO_2"), nitrogen oxide ("NO_x"), H_2S, and VOC.

25. The Division maintains that nine (9) of the ten (10) excess emissions events underlying the Lovington Violations do not qualify for affirmative defenses under the New Mexico Air Quality Control Act or the Penalty Policy, and therefore DCP is subject to penalties for one hundred and fifty-five (155) of the Lovington Violations. DCP maintains that its affirmative defense claims are valid.

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Lynch Booster Station

26. Since July 29, 2015, the Lynch Booster Station has been authorized to operate under NSR Permit 0609-M7.

27. The following table from NSR Permit 0609-M7, Condition A.106 – "Facility: Allowable Emissions," lists the emission units and their allowable emission limits. *See* 40 CFR Part 50; 40 CFR Part 63, Subparts A and ZZZZ; and 20.2.72.210.A and B(1) NMAC:

Table 7: Lynch, Table 106.A: Allowable Emissions

Unit No.	NO_x[1] (pph)	NO_x[1] (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)	SO_2 (pph)	SO_2 (tpy)
1	4.4	19.3	4.4	19.3	2.4	10.7	<[3]	<
2	4.4	19.3	4.4	19.3	2.4	10.7	<	<
3	4.4	19.3	4.4	19.3	2.4	10.7	<	<
4	4.4	19.3	4.4	19.3	2.4	10.7	<	<
5	4.4	19.3	4.4	19.3	2.4	10.7	<	<
TK-6	-[2]	-	-	-	*[4]	5.9	-	-

1 Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2
2 "-" indicates the application represented emissions of this pollutant are not expected
3 "<" indicates the application represented uncontrolled emissions are less than 1.0 pph or 1.0 tpy for this pollutant. Allowable limits are not imposed on this level of emissions, except for flares and pollutants with controls.
4 "*" indicates hourly emission limits are not appropriate for this operating situation

28. The following table from NSR Permit 0609-M7, Condition A.107 – "Facility: Allowable Startup, Shutdown, and Maintenance and Malfunction Emissions," lists the facility-wide SSM and malfunction emission limits:

Table 8: Lynch, Table 107.A: Allowable SSM and Malfunction Units, Activities, and Emission Limits

Unit No.	Description	VOC (tpy)
SSM/M	[1]Venting of Gas Due to SSM and	10

[1]This authorization does not include VOC combustion emissions.

29. Between February 12, 2018 and June 30, 2019, DCP reported forty-five (45) excess emission events and asserted affirmative defenses as provided by 20.2.7 NMAC.

30. Two NOVs were issued for eleven of these alleged violations: DCP-0641-1802 on November 1, 2018, and DCP-0641-1803 on December 7, 2019.

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31. The Division alleges that DCP violated NSR Permit 0609-M7, Conditions A106.A and A107.A, by exceeding the permitted allowable emission limits of the vent during forty-five (45) excess emission events. These events resulted in a total of three hundred and eighty-one (381) alleged violations ("Lynch Violations"). exceeding permitted allowable emissions by 279,693.69 pounds of VOC and NO_X.

32. The Division alleges that the Lynch Violations resulted in the unlawful emission of 279,693.69 pounds of VOC and NO_x.

33. The Division maintains that forty-four (44) of the forty-five (45) excess emissions events underlying the Lynch Violations do not qualify for affirmative defenses under the New Mexico Air Quality Control Act or the Penalty Policy, and therefore DCP is subject to penalties for three hundred and eighty (380) of the Lynch Violations. DCP maintains that its affirmative defense claims are valid.

Monument Booster Station

34. Between August 6, 2014 and October 16, 2018, the Monument Booster Station was authorized to operate under NSR Permit 0123-M6R2. Since October 16, 2018, the Monument Booster Station has been authorized to operate under NSR Permit 0123-M6R3.

35. The following table from NSR Permit 0123-M6R2, Condition A.106 – "Facility: Allowable Emissions," lists the emission units and their allowable emission limits. *See* 40 CFR Part 50; 40 CFR Part 63, Subparts A and ZZZZ; and 20.2.72.210.A and B(1) NMAC:

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Table 9: Monument, Table 106.A: Allowable Emissions

Unit No.		NO_x[1] (pph)	NO_x[1] (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)
3		6.5	28.4	0.6	2.8	0.7	3.1
4		0.9	3.7	0.6	2.6	0.2	0.9
TK-7		-[2]	-	-	-	*[3]	3.0
TK-8		-	-	-	-	*	4.4
Flash		-	-	-	-	*	1.2
Load		-	-	-	-	*	2.8
Flare		0.15	0.66	0.82	3.6	0.14	0.61
Fug		-	-	-	-	*	7.9

1 Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2
2 "-" indicates the application represented emissions of this pollutant are not expected
3 "*" indicates hourly emission limits are not appropriate for this operating situation

36. The following table from NSR Permit 0123-M6R3, Condition A.106 – "Facility Allowable Emissions," lists the emission units and their allowable emission limits. *See* 40 CFR Part 50; 40 CFR Part 63, Subparts A and ZZZZ; 20.2.72.210.A and B(1) NMAC:

Table 10: Monument, Table 106.A: Allowable Emissions

Unit No.	NO_x[1] (pph)	NO_x[1] (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)
3	6.5	28.4	0.6	2.8	0.7	3.1
4	0.9	3.7	0.6	2.6	0.2	0.9
TK-7	-[2]	-	-	-	*[3]	3.0
TK-8b	-	-	-	-	*	3.0
Flash	-	-	-	-	*	1.2
Load	-	-	-	-	*	2.8
Flare	0.2	0.7	0.8	3.6	0.03	0.14

1 Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2
2 "-" indicates the application represented emissions of this pollutant are not expected
3 "*" indicates hourly emission limits are not appropriate for this operating situation

37. The following table from NSR Permit 0123-M6R2 and M6R3, Condition A.107 – "Facility: Allowable SSM and Malfunction Emissions," lists the SSM and malfunction emission limits:

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Table 11: Monument, Table 107.A, Allowable SSM and Malfunction Units, Activities, and Emission Limits

Unit No.	Description	VOC (tpy)	H_2S (tpy)
SSM from Units 3-4	Compressor & Associated Piping Blowdowns during Routine and Predictable Startup, Shutdown, and/or Maintenance (SSM); and Malfunction emissions.	3.9	0.22

(This authorization does not include VOC combustion emissions)

38. Between September 1, 2018 and June 30, 2019, DCP reported twenty-one (21) excess emissions events and asserted affirmative defense claims as provided by 20.2.7 NMAC.

39. The Division alleges that DCP violated NSR Permits 0123-M6R2 and -M6R3, Conditions A106.A and A107.A, by exceeding the permitted allowable emission limits from the unit Flare during twenty-one (21) excess emission events. These events resulted in a total of two hundred and forty-nine (249) alleged violations ("Monument Violations").

40. The Division alleges that the Monument Violations resulted in the unlawful emission of 4,756 pounds of CO, SO_2, VOC and NOx.

41. The Division maintains that twenty (20) of the twenty-one (21) excess emissions events underlying the Monument Violations do not qualify as emergencies, startup, shutdown, or malfunctions under the Act or the Penalty Policy, and therefore DCP is subject to penalties for two hundred and thirty-three (233) of the Monument Violations. DCP maintains that its affirmative defense claims are valid.

Sand Dunes Compressor Station

42. From October 24, 2006 to January 24, 2019, the Sand Dunes Compressor Station was authorized to operate under NSR Permit 1201-M6.

43. Since January 25, 2019, the Sand Dunes Compressor Station has been authorized to operate under NSR Permit 1201-M7R4.

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44. The following table from NSR Permit 1201-M6, Table 2.1 lists the emission units and their allowable emission limits. Malfunction and SSM are not listed separately. *See* 20.2.72.210 NMAC, paragraphs A and B.1.

Table 12: Sand Dunes, Table 2.1, Allowable Emissions

Unit No.	NO_x[1] (pph)	NO_x[1] (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)
1	4.4	19.3	4.4	19.3	1.8	7.7
2	4.4	19.3	4.4	19.3	1.8	7.7
3	4.5	19.9	4.5	19.9	2.0	8.7
4	4.4	19.3	4.4	19.3	1.8	7.7
5	4.5	19.9	4.5	19.9	2.0	8.7
F-2	-[2]	-	-	-	42.7	0.7
F-3	-	-	-	-	N/A	30

1 Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2
2 "-" indicates that in accordance with the application, emissions of this pollutant are not expected.

45. The following table from NSR Permit 1201-M7R4, Condition A.106 – "Facility: Allowable Emissions," lists the emission units and their allowable emission limits. *See* 40 CFR Part 50; 40 CFR Part 63, Subparts A and ZZZZ; and 20.2.72.210.A and B(1) NMAC:

Table 13: Sand Dunes, Table 106.A: Allowable Emissions

Unit No.			NO_x[1] (pph)	NO_x[1] (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)
1			4.4	19.3	4.4	19.3	1.8	7.7
2			4.4	19.3	4.4	19.3	1.8	7.7
3			4.5	19.7	4.5	19.7	2.0	8.7
4			4.4	19.3	4.4	19.3	1.8	7.7
5			4.5	19.7	4.5	19.7	2.0	8.7
F-2			-[2]	-	-	-	*[3]	0.3
TK-1a			-	-	-	-	*	4.4

1 Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2
2 "-" indicates that application represented emissions of this pollutant are not expected
3 "*" indicates hourly emission limits are not appropriate for this operation

46. The following table from NSR Permit 1201-M7R4, Condition A.107 – "Facility: Allowable SSM and Malfunction Emissions," lists the facility-wide SSM emission limits:

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Table 14: Sand Dunes, Table 107.A: Allowable SSM Units, Activities, and Emission Limits

Unit No.	Description	VOC (tpy)
SSM from F-3	[1]Emergency Blowdown	30

1 This authorization does not include VOC combustion emissions

47. Between January 2, 2018 and June 30, 2019, DCP reported forty-six (46) excess emission events and asserted affirmative defenses as provided by 20.2.7 NMAC.

48. The Bureau issued two NOVs for a portion of these alleged violations: DCP-0302-1801 on November 15, 2018, and DCP-0302-1802 on January 31, 2019.

49. The Division alleges that DCP violated NSR Permit 1201-M6 or 1201-M7R4, Tables 14 and 15, by exceeding the permitted allowable emission limits of the emergency blowdown vent during forty-six (46) excess emission events. These events resulted in a total of one hundred and twenty-five (125) alleged violations ("Sand Dunes Violations").

50. The Division alleges that the Sand Dunes Violations resulted in the unlawful emission of 228,549.52 pounds of VOC.

51. The Division maintains that thirty-eight (38) of the forty-six (46) excess emission events underlying the Sand Dunes Violations do not qualify for affirmative defenses under the Act or the Penalty Policy, and therefore DCP is subject to penalties for one-hundred seventeen (117) of the Sand Dunes Violations. DCP maintains that its affirmative defense claims are valid.

South Hat Booster Station

52. Between November 22, 2010 and August 13, 2018, South Hat Booster Station was authorized to operate under NSR Permit 1018-M7.

53. Between May 21, 2012 and January 11, 2018, South Hat Booster Station was authorized to operate under Title V Permit P044-R3.

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54. Between January 12, 2018, and August 13, 2018, South Hat Booster Station was authorized to operate under Title V Permit P044-R4. That permit was terminated on August 14, 2018.

55. Since August 14, 2018, South Hat Booster Station has been authorized to operate under GCP-O&G Permit 1018-M8.

56. The following table from Title V Permit P044-R3, Condition A.106 – "Facility: Allowable Emissions," lists the emission units, and their allowable emission limits. *See* 40 CFR Part 50; 40 CFR Part 60, Subparts A & JJJJ; 40 CFR Part 63, Subparts A & ZZZZ; 40 CFR Part 64; 20.2.70.302.A(1), (7), and (8) NMAC; and NSR Permit 1018-M7:

Table 15: South Hat, Table 106.A, Allowable Emissions

Unit No.		NO_x[1] (pph)	NO_x[1] (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)
1		5.3	23.2	5.3	23.2	1.8	7.7
2		5.3	23.2	5.3	23.2	1.8	7.7
3		5.4	23.7	5.4	23.7	1.8.	7.8
4		5.4	23.7	5.4	23.7	1.8	7.8
5		5.3	23.2	5.3	23.2	1.8	7.7
6		5.3	23.2	5.3	23.2	1.8	7.7
7		9.8	28.642.8	9.8	42.8	3.3	14.3
8		6.5	28.6	5.2	22.9	3.3	14.3
TK-6		-[2]	-	-	-	<[3]	2.7
TK-7		-	-	-	-	<	2.7
Load		-	-	-	-	<	1.5
Total[4]		-	211.3			<	81.8

1 Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2
2 "_" indicates the application represented emissions of this pollutant are not expected
3 "<" indicates the application represented uncontrolled emissions are less than 1.0 pph or 1.0 tpy for this pollutant. Allowable limits are not imposed on this level of emissions, except for flares and pollutants with controls.
4 Total allowables are for information and are not enforceable conditions

57. The following table from Title V Permit P044-R3, Condition A.107 – "Facility: Allowable Startup, Shutdown, and Maintenance and Malfunction Emissions," lists the facility-wide SSM and malfunction emission limits:

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Table 16: South Hat, Table 107.A, Allowable SSM and Malfunction Units, Activities, and Emission Limits

Unit No.	Description	VOC (tpy)
SSM from 1, 2, 3, 4, 5, 6, 7, 8	Compressor & Associated Piping Blowdowns during Routine and Predictable Startup, Shutdown, and/or Maintenance (SSM)	1.9
M1	Venting [2] of Gas due to Malfunctions.	10.0
Total [1]		11.9

1 Totals are for information only, not enforceable conditions.
2 This authorization does not include VOC combustion emissions.

58. Title V Permit P044-R4, Tables 106.A and 107.A unit emission limits are equal to Title V Permit P044-R3.

59. The following table from Oil and Gas GCP Application Table 2: "Allowable Emission Limits" lists (beginning August 14, 2018) the maximum allowable, facility-wide SSM and malfunction emission limits:

Table 17: South Hat, Table 2. Oil and Gas GCP Application, Allowable Emission Limits

Unit No.	NO_x[1] (pph)	NO_x[1] (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)	SO_2 (pph)	SO_2 (tpy)
1	0.22	0.97	0.44	1.93	0.056	0.25	0.0035	0.015
2	0.22	0.97	0.44	1.93	0.056	0.25	0.0035	0.015
3	0.29	1.28	0.41	1.78	0.044	0.19	0.0032	0.014
4	0.29	1.28	0.41	1.78	0.044	0.19	0.0032	0.014
5	0.22	0.97	0.44	1.93	0.056	0.25	0.0035	0.015
6	0.22	0.97	0.44	1.93	0.056	0.25	0.0035	0.015
7	1.06	4.64	2.57	11.24	0.13	0.58	0.0065	0.028
8	1.06	4.64	2.57	11.24	0.13	0.58	0.0065	0.028
TK-6	-[2]	-	-	-	*	6.31	-	-
TK-7	-	-	-	-	*	6.31	-	-
Load	-	-	-	-	*	0.69	-	-
Fug[3]	-	-	-	-	4.99	21.88	-	-
SSM[4]	-	-	-	-	*	50.00	-	-
Malfunction[5]	-	-	-	-	*	10.00	-	-
Total[4]	3.59	15.71	7.71	33.76	5.57	97.71	0.033	0.15

[1] Significant Figures Examples: One significant figure – 0.03, 3, 0.3. Two significant figures – 0.34, 34, 3400, 3.4
[2] Condensable PM: Include condensable particulate matter emissions in particulate matter calculations.
[3] FUG: Pursuant to condition A106 of the permit, fugitive emissions of VOC do not typically count toward Title V or PSD applicability. Thus, the total VOC emissions, including fugitive sources, may exceed 100 tpy without triggering additional permitting requirements.
[4] SSM and Malfunction: As stated in NMED's *Implementation Guidance for Permitting SSM Emissions and Excess Emissions* document (June 2012): there is no limit to the quantity of SSM emissions that can be permitted,

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provided they are routine and predictable DCP would like to request 50 tpy of VOC and 1 tpy of HAP. In addition, pursuant to condition A107.C the permittee may select to authorize up to 10 tpy of malfunction events. DCP is requesting 10 tpy of VOC and 1 tpy of HAP associated with malfunction events in addition to the aforementioned SSM emissions limits.
"*" Denotes an hourly limit is not appropriate and is not being requested.

60. Between January 5, 2018 and June 30, 2019, DCP reported one hundred and nine (109)[2] excess emission events and asserted affirmative defenses as provided by 20.2.7 NMAC.

61. The Bureau issued two NOVs for sixty-nine (69) of these alleged violations: DCP-0665-1801 on December 14, 2018, and DP-0665-1802 and February 4, 2019.

62. The Division alleges that DCP violated Title V Permits P044-R3 and P044-R4, Conditions A106.A and A107.A, and GCP Oil and Gas Permit 1018-M8, Table 2, by exceeding its permitted allowable emission limits through a vent during one hundred and fourteen (114) excess emission events. These events resulted in a total of five hundred and ninety-seven (597) alleged violations (the "South Hat Violations").

63. The Division alleges that the South Hat Violations resulted in the unlawful emission of a total of 687,013.20 pounds of VOC.

64. The Division maintains that one hundred and three (103) of the one hundred and nine (109) excess emission events underlying the South Hat Violations do not qualify for affirmative defenses under the Act or the Penalty Policy, and DCP is therefore subject to penalties for five hundred and eighty (580) of the South Hat Violations. DCP maintains that its affirmative defense claims are valid.

[2] Revised Compliance Order No. AQB-20-46 stated that 69 excess emission events were reported and included in the two NOVs, and a total of 114 excess emission events were reported. DCP's Answer identified that five events were included in both one of the NOVs and an exhibit of excess emission reports not included in any NOV, resulting in a total of 109 excess emission reports.

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West Turkey Track Compressor Station

65. From June 28, 2013 to April 1, 2020, the West Turkey Track Compressor Station was authorized to operate under NSR Permit 2098-M4, GCP-4.

66. The following table from NSR Permit 2098-M4, GCP-4 Application Table 5: "Flares [Condition VII Line 5]," lists the emission units and their allowable emission limits:

Table 4: West Turkey Track, Table 5, Flares (abbreviated)

Unit No.	NO_x[1] (pph)	NO_x[1] (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)
Flare	0.03	0.15	0.19	0.81	0.03	0.14

67. Between June 3, 2018 and June 30, 2019, DCP reported twenty-seven (27) excess emission events and asserted affirmative defenses as provided by 20.2.7 NMAC.

68. The Department issued NOV DCP-413-1801 for a portion of these alleged violations on January 31, 2019.

69. The Department alleges that DCP violated GCP Oil and Gas Permit 2098-M4, Application Table 5: "Flares [Condition 7 Line 5]," by exceeding the permitted allowable emission limits for the unit Flares during twenty-seven emissions events. These events resulted in a total of two hundred and forty-two (242) alleged violations ("West Turkey Violations").

70. The Division alleges that the West Turkey Violations resulted in the unlawful emission of 49,896.50 pounds of NO_x, CO, and VOC.

71. The Division maintains that twenty-four (24) of the twenty-seven (27) excess emission events underlying the West Turkey Violations do not qualify for affirmative defenses under the Act or the Penalty Policy, and DCP is therefore subject to penalties for two hundred and eighteen (218) of the West Turkey Violations. DCP maintains that its affirmative defense claims are valid.

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Artesia Gas Plant

72. Since June 27, 2017, the Artesia Gas Plant has been authorized to operate under Title V Permit P095-R3.

73. The following table from Title V Permit P095-R3, Condition A106 Facility: Allowable Emissions, lists, in part, the applicable emission units and their allowable emission limits (40 CFR 50; 40 CFR 60, Subparts A and JJJJ; 40 CFR 63, Subparts Kb and KKK; 40 CFR 63, Subparts A, HH, and ZZZZ; Paragraphs 1, 7, and 8 of 20.2.70.302.A NMAC; and NSR Permit 0434M10) (only applicable emission units listed):

Table 19: Artesia Gas Plant, Table 106.A, Allowable Emissions

Unit No.	NO_x[1] (pph)	NO_x (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)	SO_2 (tpy)	H_2S (tpy)
23	0.09	0.38	0.47	2.06	-	-	0.04	3.9E-5

[1] Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2
[2] "-" indicates the application represented emissions of this pollutant are not expected
[3] Compliance with emergency flare emission limits is demonstrated by limiting combustion to pilot and/or purge gas only.

74. The following table from Title V Permit P095-R3, Condition A107 Facility: Allowable Startup, Shutdown, and Maintenance ("SSM") and Malfunction Emissions, lists the facility-wide startup, shutdown, and maintenance, and malfunction emission limits (only applicable emission units and information listed):

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Table 20: Artesia Gas Plant, Table 107.A, Allowable SSM & M Units and Emission Limits

Unit No.	Description	NO_x (pph)	NO_x (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)	SO_2 (pph)	SO_2 (tpy)	H_2S (pph)	H_2S (tpy)
SSM (23)	Flaring during routine and predictable startup, shutdown, and/or maintenance	10.4	2.4	56.6	13.2	<	<	2001.0	328.2	21.3	3.5
M	Venting of gas and combustion of gas flared due to malfunction	*	10.0	*	10.0	*	10.0	*	10.0	*	9.0

"<" Indicates that the application represented the uncontrolled mass emission rates are less than 1.0 pph or 1.0 tpy for this emissions unit and this air pollutant. The Department determined that allowable mass emission limits were not required for this unit and this pollutant.

"*" Pound per hour (pph) emission limits for SSM 23 shall apply during malfunction flaring events.

75. Between May 18, 2018 and June 14, 2018, DCP reported four (4) excess emission events at the Artesia Gas Plant and asserted affirmative defenses as provided by 20.2.7 NMAC.

76. The Bureau issued NOV DCP-0199-1801 for these alleged violations on March 18, 2019.

77. The Division alleges that DCP violated Title V Permit P095-R3, Condition A106.A by exceeding the permitted allowable emission limits of the emergency acid gas flare during four (4) excess emission events. These events resulted in a total of two hundred and sixty (260) alleged violations ("Artesia Violations").

78. The Division alleges that the Artesia Violations resulted in the unlawful emission of 99,768 pounds of NO_x, CO, SO_2, VOC and H_2S.

79. The Division maintains that the excess emissions events underlying the Artesia Violations do not qualify for affirmative defenses under the Act or the Penalty Policy, and DCP is

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therefore subject to penalties for those violations. DCP maintains that its affirmative defense claims are valid.

Eunice Gas Plant

80. Since December 11, 2013, the Eunice Gas Plant has been authorized to operate under Title V Permit P086-R2.

81. The following table from Title V Permit P086-R2, Condition A106 Facility: Allowable Emissions, lists the emission units and their allowable emission limits (40 CFR 50; 40 CFR 60, Subpart A and GG, Kb, KKK; 40 CFR 63, Subpart A and HH, Paragraphs 1, 7, and 8 of 20.2.70.302.A NMAC; and NSR Permit 0044M10) (only applicable emission units listed):

Table 21: Eunice Gas Plant, Table 106.A, Allowable Emissions

Unit No.	NO_x[1] (pph)	NO_x[1] (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)	SO_2 (pph)	SO_2 (tpy)	H_2S (pph)	H_2S (tpy)
SRU Incinerator (31)	3.6	15.8	4.0	17.7	0.2	0.87	629.7[3]	2,758	6.8	29.9
ESD Flare (112A)	0.43	1.9	2.3	10.2	-	-	0.45	0.2	4.5E-05	2.0E-04
Acid Gas Flare (113)	0.1	0.36	0.45	2.0	-	-	0.0087	0.038	8.6E-06	3.8E-05
Booster Flare (114)	0.1	0.46	0.57	2.5	-	-	0.011	0.048	1.1E-05	4.8E-05

[1] Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2
[2] "-" indicates the application represented emissions of this pollutant are not expected
[3] "<" SO2 emissions shall not exceed 629.7 pounds per hour during any three-hour period.

82. The following table from Title V Permit P086-R2, A107 Facility: Allowable Startup, Shutdown, & Maintenance ("SSM") and Malfunction Emissions, lists the facility-wide startup, shutdown, and maintenance, and malfunction emission limits (only applicable emissions listed):

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Table 22: Eunice Gas Plant, Table 107.A, Malfunction Emission Limit

Unit No.	NO_x (pph)	NO_x (tpy)	CO	CO (tpy)	VOC (pph)	VOC (tpy)	SO_2 (pph)	SO_2 (tpy)	H_2S (pph)	H_2S (tpy)
SSM-113	8.57	0.92	46.7	5.0	5.9	0.18	4233.9	128.8	52.9	1.37
Malfunction						10.0				

83. Between May 1, 2017 and August 16, 2018, DCP reported one hundred and thirty-one (131) excess emission events at the Eunice Gas Plant and asserted affirmative defenses as provided by 20.2.7 NMAC.

84. The Bureau issued four NOVs for these alleged violations: DCP-0595-1702 on January 29, 2018; DCP-0595-1801 on March 7, 2018; DCP-0595-1802 on November 19, 2018; and DCP-0595-1804 December 14, 2018.

85. The Division alleges that DCP violated Title V Permit P086-R2, Conditions A106.A and A107A, by exceeding the permitted allowable emissions of a vent or the ESD or Acid gas flares during one hundred and thirty-one (131) events. These events resulted in a total of two thousand one hundred and seventy-two (2,172) alleged violations ("Eunice Violations").

86. The Division alleges that the Eunice Violations resulted in the unlawful emission of 396,664 pounds of NO_x, CO, SO_2, VOC, and H_2S.

87. The Division maintains that one hundred and sixteen (116) of the one hundred and thirty-one (131) excess emission events underlying the Eunice Violations do not qualify for affirmative defenses under the Act or the Penalty Policy, and therefore DCP is subject to penalties for one thousand eight hundred and eighty-two (1,882) of the Eunice Violations. DCP maintains that its affirmative defense claims are valid.

Linam Ranch Gas Plant

88. Since April 28, 2014, the Linam Ranch Gas Plant has been authorized to operate under Title V Permit P094-R2.

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89. The following table from Title V Permit P094-R2, Condition 106.A, Allowable Emissions, lists the emission units and their allowable emission limits:

Table 23: Linam Ranch Gas Plant, Table 106.A, Allowable Emissions

Unit No.	NO_x[1] (pph)	NO_x[1] (tpy)	CO (pph)	CO (tpy)	VOC (pph)	VOC (tpy)	SO_2 (pph)	SO_2 (tpy)
6	39.3	566	20	283	3.1	60.9	<	0.12
10	47.5	566	24	283	6.5	60.9	<	0.12
28	3.5	15.2	3.5	15.4	2.0	8.8	0.9	4.0
30	11.3	49.3	9.0	39.5	0.3	1.4	0.3	1.1
36	5.5	24.2	9.3	40.7	0.6	2.7	<	<
37	5.5	24.2	9.3	40.7	0.6	2.7	<	<

[1] Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_x
"<" indicates the application represented uncontrolled emissions less than 1.0 pph or 1.0 tpy for this pollutant.

90. The following table from Title V Permit P094-R2, A107 Facility: Allowable Startup, Shutdown, & Maintenance ("SSM") and Malfunction Emissions, lists the facility-wide startup, shutdown, and maintenance, and malfunction emission limits (only applicable emissions listed):

Table 24: Linam Ranch Gas Plant, Table 107.A, Malfunction Emission Limit

Unit No.	NO_x[1] (pph)	NO_x[1] (tpy)	CO	CO (tpy)	VOC (pph)	VOC (tpy)	SO_2 (pph)	SO_2 (tpy)	H_2S (pph)	H_2S (tpy)
SSM 2	15.0	0.88	81.0	4.8	1.6	0.01	7,751	46.0	84.0	0.48
SSM AGI	18.0	0.71	97.0	44.0	1.90	0.00	9,301	4.1	101	0.048
Malfunction	288	10.0	1,565	10.0	3,029	10.0	9,301	10.0	101	9.0

[1] Nitrogen dioxide emissions include all oxides of nitrogen expressed as NOx
Venting of gas due to malfunctions that does not include VOC combustion emissions

91. Between May 16, 2017 and April 30, 2018, DCP reported one hundred and sixty-three (163) excess emission events and asserted affirmative defenses as provided by 20.2.7 NMAC.

92. The Bureau issued three NOVs for these alleged violations: DCP-0589-1702 on January 30, 2018; DCP-0589-1801 on March 7, 2018; and DCP-0589-1802 on September 28, 2018.

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93. The Division alleges that DCP violated Title V Permit P094-R2, Conditions A106.A and 107.A, by exceeding the permitted allowable emission limits of multiple units during one hundred and sixty-three (163) excess emission events. These events resulted in a total of four thousand one hundred and forty-four (4,144) alleged violations ("Linam Ranch Violations").

94. The Division alleges that the Linam Ranch Violations resulted in the unlawful emission of 890,678 pounds of NO_x, CO, SO_2, VOC, and H_2S.

95. The Division maintains that one hundred and thirty-five (135) of the one hundred and sixty-three (163) excess emissions events underlying the Linam Ranch Violations do not qualify for affirmative defenses under the Act or the Penalty Policy, and therefore DCP is subject to penalties for two thousand three hundred and thirty-six (2,336) of the Linam Ranch Violations. DCP maintains that its affirmative defense claims are valid.

Zia II Gas Plant

96. Between December 22, 2016 and November 22, 2017, the Zia II Gas Plant was authorized to operate under PSD Permit PSD-5217M1-R2. Since November 22, 2017, the Zia II Gas Plant has been authorized to operate under PSD Permit PSD-5217M2.

97. The following table from PSD Permits PSD-5217M1-R2 and PSD-5217M2, Condition 107.A Facility: Allowable Startup, Shutdown, & Maintenance ("SSM") Emissions, lists the facility-wide startup, shutdown, and maintenance emission limits:

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Table 25: Zia II Plant, Table 107.A, Allowable SSM Emission Limits

Unit No.	NO_x[1] (pph) BACT	NO_x[1] (tpy)	CO (pph) BACT	CO (tpy)	VOC (pph) BACT	VOC (tpy)	SO_2 (pph) BACT	SO_2 (tpy)	H_2S (pph)	H_2S (tpy)	CO_{2e} (typ) BACT
SSM FL1	799.2	3.9	4,348.8	21.1	2,942.1	11.8	14,977.	59.9	162.9	0.7	6,518
SSM FL2	102.0	1.2	554.8	6.5	7.8	0.09	4,409.8	22.0	48.0	0.2	1,094
SSM Compressor Blowdown (CB)	-	-	-	-	358.8	0.8	-	-	-	-	15
SSM Plant Venting (PV)	-	-	-	-	1,500.0	12.0	-	-	-	-	3,355

[1] Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2
[2] Pound per hour limits for NOx, CO, VOC, and SOx and the ton per year limit for CO2e are PSD BACT limits for units FL1, FL2, and SSM Compressor Blowdown and Plant Venting.
[3] Allowable SSM emission limits for FL1 and FL2 for all pollutants include pilot and purge emissions, except for CO2e which has separate emission limits for SSM and pilot and purge. Emission limits for pilot and purge appear in Table 106B.
[4] SSM for FL2 includes assist gas and acid gas (not pilot or purge).

98. Between September 6, 2017 and August 31, 2018, DCP reported two hundred and thirty-five (235) excess emission events at the Zia II Gas Plant and asserted affirmative defenses as provided by 20.2.7 NMAC.

99. The Bureau issued three NOVs for these alleged violations: DCP-32800-1801 on March 21, 2018; DCP-32800-1802 on November 16, 2018; and DCP-32800-1803 on February 20, 2019.

100. The Division alleges that DCP violated PSD Permits PSD-5217M1-R2 and -M2, Condition A107.A by exceeding the permitted allowable emission limits for multiple units during two hundred and thirty-five (235) events. These events resulted in a total of six thousand seven hundred and one (6,701) alleged violations ("Zia II Violations").

101. The Division alleges that the Zia II Violations resulted in the unlawful emission of 251,197 pounds of NO_x, CO, SO_2, VOC, and H_2S.

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102. The Division maintains that two hundred and twenty-two (222) of the two hundred and thirty-five (235) excess emissions events underlying the Zia II Violations do not qualify for affirmative defenses under the Act or the Penalty Policy, and therefore DCP is subject to penalties for six thousand and thirty (6,030) of the Zia II Violations. DCP maintains that its affirmative defense claims are valid.

C. SUMMARY OF ADMINISTRATIVE COMPLIANCE ORDERS

103. On May 13, 2020, the Division issued an Administrative Compliance Order alleging violations for the eight compressor or booster stations.

104. On June 30, 2020, the Division issued a Revised Administrative Compliance Order ("Compressor Station ACO") alleging violations for the eight compressor or booster stations superseding the May 13, 2020 Administrative Compliance Order.

105. On July 30, 2020, DCP filed its Request for Hearing and Answer to the Compressor Station ACO, denying the alleged violations and proposed civil penalty, and requesting that after a hearing, the Secretary of the Department dismiss the Compressor Station ACO with prejudice and such other relief as the Secretary deems just and appropriate. The Department docketed this matter as AQB 20-46 (CO).

106. On August 28, 2020, the Division issued an Administrative Compliance Order ("Gas Plant ACO") alleging violations for the four gas plants.

107. On September 25, 2020, DCP filed its Request for Hearing and Answer to the Gas Plant ACO, denying the alleged violations and proposed civil penalty, and requesting that after a hearing, the Secretary of the Department dismiss the Gas Plant ACO with prejudice and such other relief as the Secretary deems just and appropriate. The Department docketed this matter as AQB 20-64 (CO).

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108. DCP identified a total of 194 excess emissions events at eight (8) compressor or booster station facilities for which a civil penalty is barred, in whole or in part, by the 1-year statute of limitations for administrative compliance orders in NMSA 1978, § 74-2-12.A(1) (2006). *See* DCP Operating Company's Request for Hearing and Answer to Revised Administrative Compliance Order, AQB 20-46 (CO), p. 18, ¶ 2.

II. COMPROMISE AND SETTLEMENT

A. GENERAL

109. Following good faith settlement negotiations to resolve this matter without further costly litigation, the Parties agree to a complete settlement of all the violations alleged in the Compressor Station ACO and the Gas Plant ACO, including DCP's affirmative defense claims, and have consented to the terms of this Final Order. DCP does not admit any of the violations alleged in the ACOs and does not waive or concede its affirmative defense claims, and the Division does not concede that DCP met its burden on the affirmative defense claims.

110. The Parties admit jurisdiction and consent to the relief specified herein.

B. CIVIL PENALTY, INJUNCTIVE RELIEF, AND COMPLIANCE ASSURANCE

111. In compromise and settlement of all of the violations alleged in the Compressor Station ACO and the Gas Plant ACO, and upon consideration of the seriousness of the alleged violations and DCP's efforts to address the causes of excess emissions at the Facilities, the Parties agree that DCP shall: (1) pay a civil penalty of $950,000 in a cash payment to the State of New Mexico; (2) permanently cease operation of its Eunice Gas Plant, with the exception of those operations identified in paragraph 112, and surrender or modify, as set forth in paragraph 116, its permits for the Eunice Gas Plant; and (3) comply with additional requirements relating to operations at its gas plant facilities, as set forth below.

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112. The requirement to cease operations of the Eunice Gas Plant does not apply to those specific operations located at the Eunice Gas Plant that are associated with the compressor station known as the "Amanda Compressor Station," and those liquids stabilization and loading/unloading facilities known as the "Eunice Treater."

Civil Penalty

113. DCP shall pay a civil penalty of $950,000.00 to the State of New Mexico within 30 calendar days after the effective date of this Final Order.

114. Payment shall be made to the ***State of New Mexico General Fund, NMED-Air Quality Bureau, 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico, 87505*** by certified or corporate check, or by wire transfer (ACH deposit). On the date that delivery of funds is initiated, notify the Air Quality Bureau Enforcement Manager by email at cindy.hollenberg@state.nm.us.

Certified or corporate checks must be sent to the following address:

New Mexico Environment Department
Air Quality Bureau
c/o Compliance and Enforcement Manager
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505

Wire transfers must be made to Wells Fargo Bank as follows:

Wells Fargo Bank, N.A.
100 W Washington Street, Floor 20
Phoenix, AZ 85003

Routing Transit Number: 121000248
Deposit Account Number: 4123107799
Descriptor: NMED-AQB-C&E

115. If DCP fails to make timely and complete payment of the civil penalty pursuant to paragraphs 113 and 114, and unless the Parties agree to extend the time for payment of the civil

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penalty, DCP shall pay a stipulated penalty of $1,500.00 per day for each day the payment is not timely or complete.

Shutdown of Eunice Gas Plant

116. Within 60 days of the effective date of this Final Order, DCP shall permanently cease operations at the Eunice Gas Plant, except as specified in paragraph 112. Within the 60-day period, DCP shall surrender its authority to continue to operate the Eunice Gas Plant under the AQCA by filing: (1) an administrative revision to the NSR permit removing the SRU and other equipment associated with the gas plant and deleting conditions relating to those units, with the exception of conditions, provisions and authority to operate relating to the Amanda Compressor Station and the Eunice Treater; and (2) an administrative modification to the Title V permit terminating the permit.

117. In addition to permanently ceasing operations at the Eunice Gas Plant as specified in paragraph 116 and complying with the requirements of paragraph 116, DCP shall decommission the Eunice Gas Plant by removing process chemicals, including catalysts, and cleaning process vessels and piping within 270 days of the effective date of this Final Order. Within 30 days of the decommission completion date, DCP shall submit a written certification to the Department that the facility was properly decommissioned in accordance with this paragraph and applicable statutes and regulations. The certification shall include the following statement, signed by DCP's responsible official:

> *I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I have no personal knowledge that the information submitted is other than true, accurate, and complete. I am aware that there are significant penalties for*

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submitting false information, including the possibility of fines and/or revocation of air quality permits for knowingly and willfully submitting a materially false statement.

118. If DCP fails to permanently cease operations of the Eunice Gas Plant or submit the applications to surrender or modify the air quality permits issued by the Department for the Eunice Gas Plant as specified in paragraph 116 within 60 days of the effective date of this Final Order, and unless the Parties agree to extend the time by which DCP must permanently cease operations at the Eunice Gas Plant or submit the applications to surrender or modify the air quality permits issued by the Department for the Eunice Gas Plant as set forth in paragraph 116, DCP shall pay a stipulated penalty of $1,500.00 per day for each day thereafter until the date operations at the Eunice Gas Plant are permanently ceased.

119. If DCP fails to submit the written certification specified in paragraph 117 within 30 days of completing decommissioning at the Eunice Gas Plant, and unless the Parties agree to extend the time by which DCP must submit the written certification, DCP shall pay a stipulated penalty of $1,500.00 per day for each day thereafter until the date the required certification is submitted.

Compliance Assurance Requirements

120. Within 120 days from the signing of the Final Order by the Secretary of the Department, DCP shall comply with all of the requirements set forth in Appendix 1[3] at the following three facilities:

DCP Operating Company, LP, Artesia Gas Plant

DCP Operating Company, LP, Linam Ranch Gas Plant

DCP Operating Company, LP, Zia II Gas Plant

3 These requirements are based on Title V Permit P094-R3 (Linam Ranch Gas Plant), Specific Condition A206. Flares.

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To the extent that any of the requirements of Appendix 1 address emissions that are subject to requirements in existing permits for any of these facilities, the requirements of Appendix 1 shall supersede those permit requirements.

121. Within 60 days of the effective date of the Final Order, DCP shall submit applications to the Department for revision of the NSR permits for the Artesia Gas Plant and the Zia II Gas Plant to incorporate the applicable provisions set forth in Appendix 1, and to address any conflicting or duplicative provisions in the existing NSR permits.

122. The following specific compliance assurance requirements shall apply to the DCP facilities listed in Paragraph 2 for a period of two years beginning on the effective date of the Final Order:

a. In addition to the "Once per calendar year" frequency of flare inlet gas analysis required by Appendix 1, Specific Condition A206.B(2)(a), DCP shall conduct 11 additional monthly flare inlet gas analyses within the first five business days of each month to meet the standards provided in Appendix 1, Specific Condition A206.(B)(2). Results of these analyses shall be used in production of monthly flare emissions calculations per Appendix 1, Specific Condition A206.C(2)(a). This requirement shall commence on the date of the signing of this Final Order by the Secretary of the Department.

b. Within five days of the last business day of each month DCP shall compile all of the monitoring data and emissions calculations prepared for the previous month of affected facility flare operations, per the requirements of this Final order, and submit under separate NMED "Reporting Submittal Form" via electronic mail to cindy.hollenberg@state.nm.us.

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c. For any flaring event lasting longer than 3 hours continuous duration, the DCP shall prepare a root cause analysis in accordance with the requirements of 20.2.7.114 NMAC, ROOT CAUSE AND CORRECTIVE ACTION ANALYSIS, to determine the cause of the flaring event. DCP shall submit the results of any root cause analysis under this subparagraph to the Department on a monthly basis.

123. All submissions and reports required under paragraph 122 shall be submitted via email in accordance with Paragraph 108 and shall include the following statement, signed by DCP's responsible official:

> *I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I have no personal knowledge that the information submitted is other than true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fines and/or revocation of air quality permits for knowingly and willfully submitting a materially false statement.*

124. If DCP fails to submit permit applications as specified in Paragraph 121 within 60 days of this Final Order, and unless the Parties agree to extend the time by which DCP shall submit the permit applications, DCP shall pay a stipulated penalty of $1,500.00 per day for each day thereafter until the date all the required applications are submitted.

125. If DCP fails to submit the reports required in paragraph 122 of this final order within the specified timeframes, and unless the Parties agree to extend the time by which DCP shall submit a required report, DCP shall pay a stipulated penalty of 1,500.00 per day for each day thereafter until the date the required report is submitted.

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126. Within 30 days following receipt of a written demand by the Department, DCP shall make payment of any stipulated penalty that is due and payable under this Final Order. DCP shall make a cash payment of any stipulated penalty in the same manner as the civil penalty payment, as instructed in paragraph 114. DCP shall not contest or dispute in any way the amount of the stipulated penalty of $1,500.00 per day in the event that the Department brings an action against DCP to recover stipulated penalties due under paragraphs 115, 118, 119, 124 and/or 125, provided that DCP reserves the right to contest the basis for assessment of a stipulated penalty.

III. OTHER TERMS AND CONDITIONS

A. COMPLIANCE WITH OTHER LAWS AND REGULATIONS

127. Nothing in this Final Order shall relieve DCP of its obligation to comply with all applicable federal, state, and local laws and regulations.

B. RESERVATION OF RIGHTS AND DEFENSES

128. This Final Order shall not be construed to prohibit or limit the Department in any way from requiring DCP to comply with any applicable state or federal requirement not resolved herein. This Final Order shall not be construed to prohibit or limit the Department in any way from seeking any relief authorized by the AQCA for violation of any state or federal requirement applicable to DCP not resolved herein. This Final Order shall not be construed to prohibit or limit DCP in any way from raising any defense to a Department action seeking such relief.

C. MUTUAL RELEASE

129. The Parties mutually release each other from all claims that each Party raised or could have raised against the other regarding the facts and violations alleged in the NOVs, the Compressor Station ACO and the Gas Plant ACO. Such release applies only to civil liability.

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D. WAIVER OF STATE LIABILITY

130. DCP shall assume all costs and liabilities incurred in performing all obligations under this Final Order. The Department, on its own behalf and on behalf of the State of New Mexico, does not assume any liability for DCP's performance of any obligation under this Final Order.

E. EFFECTIVE DATE AND TERMINATION DATES

131. This Final Order and any modifications thereto shall be effective when the Final Order or modification has been executed by both of the Parties.

132. Except as otherwise provided in this Paragraph, the terms of this Final Order shall terminate when DCP has fulfilled the requirements of this Final Order as set forth in Paragraphs 113 through 125, provided that the requirements in paragraphs 120 and 121 shall be deemed to be satisfied when the two NSR permits have been modified to incorporate the requirements of Appendix 1 as provided by paragraph 121. The reservations of rights and defenses and the mutual release in Paragraphs 128 and 129 shall survive the execution and performance of this Final Order, and shall remain in full force and effect as an agreement between the Parties.

F. INTEGRATION

133. This Final Order merges all prior written and oral communications between the Parties concerning the subject matter of this Final Order, contains the entire agreement between the Parties, and shall not be modified without the express written agreement of the Parties.

G. BINDING EFFECT

134. This Final Order shall be binding on the Parties and their officers, directors, employees, agents, subsidiaries, successors, assigns, trustees, or receivers.

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H. AUTHORITY OF SIGNATORIES

135. The persons executing this Final Order on behalf of DCP and the Department, respectively, represent that they have the authority to execute this Final Order on behalf of DCP and the Department.

I. SIGNATURE AND COUNTERPARTS

136. This Final Order is intended to be executed on separate pages. Faxed, emailed, electronic, or digital signatures shall constitute original signatures binding on the signing party.

137. This Final Order may be executed in multiple counterparts, each of which shall be deemed an original, but all of which shall constitute one and the same agreement.

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NEW MEXICO ENVIRONMENT DEPARTMENT

Rebecca Roose Digitally signed by Rebecca Roose Date: 2021.09.10 15:35:26 -06'00'

By: _____ **Date:** _____

REBECCA ROOSE
DEPUTY SECRETARY

DocuSign Envelope ID: 8DE262AE-6A1D-477A-9B0B-B15278C26CC9

DCP OPERATING COMPANY, LP

By: DocuSigned by: Don Baldridge F884B8AD54BF4E1... **Date:** 9/9/2021

Print Name: Donald A. Baldridge

Print Title: President

NMED AIR QUALITY BUREAU
NSR AND TITLE V ADMINISTRATIVE REVISION

DCP OPERATING COMPANY, LP
Eunice Gas Plant

Prepared By:

Samuel Keen – Environmental Manager

DCP Operating Company, LP
2107 City West Blvd #600
Houston, TX 77042
(713) 735-3978

Adam Erenstein – Manager of Consulting Services

TRINITY CONSULTANTS
9400 Holly Ave NE
Bldg 3, Suite 300
Albuquerque, NM 87122
(505) 266-6611

November 2021

Project 213201.0154

ORIGINAL

Trinity Consultants

Trinity Consultants
9400 Holly Ave NE, Bldg 3, Ste 300, Albuquerque, NM 87122 / P 505.266.6611 / trinityconsultants.com

RECEIVED
NOV 05 2021
Air Quality Bureau

November 3, 2021

Permit Programs Manager
NMED Air Quality Bureau
525 Camino de los Marquez Suite 1
Santa Fe, NM 87505-1816

RE: Application for an Administrative Revision
DCP Operating Company, LP; Eunice Gas Plant

Permit Programs Manager:

DCP entered into a Settlement Agreement (No. AQB 20-64 (CO)) and Stipulated Final Compliance Order (Final Order) with NMED which was signed on September 9, 2021. Per requirement 116 of the Final Order:

"Within 60 days of the effective date of this Final Order, DCP shall permanently cease operations at the Eunice Gas Plant, except as specified in paragraph 112. Within the 60-day period, DCP shall surrender its authority to continue to operate the Eunice Gas Plant under the AQCA by filing: (1) an administrative revision to the NSR permit removing the SRU and other equipment associated with the gas plant and deleting conditions relating to those units, with the exception of conditions, provisions and authority to operate relating to the Amanda Compressor Station and the Eunice Treater; and (2) an administrative modification to the Title V permit terminating the permit."

On behalf of DCP Operating Company, LP, Trinity Consultants is submitting an application for an administrative revision for the Eunice Gas Plant Facility, currently authorized to operate under NSR Permit No. 0440-M11R1 and Title V Permit No. P086R2. With this application, DCP seeks to cease operations of the entire Eunice Gas Plant facility, except for operations related to the Amanda Compressor Station and the Eunice Treater, cancel the construction permit, and voluntarily discontinue the Title V permit. GCP-O&G applications for the Amanda Compressor Station and Eunice Treater were submitted to the NMED on November 3, 2021.

The format and content of this application are consistent with the Bureau's current policy regarding administrative revision applications; it is a complete application package. Enclosed is the hard and copy of the application. Please feel free to contact me by email at aerenstein@trinityconsultants.com if you have any questions regarding this application.

Sincerely,

Adam Erenstein
Manager of Consulting Services

Cc: Samuel Keen, P.E. (DCP Operating Company, LP)
Trinity Project File 213201.0154

Permitting Administrative Multi-Form

Use for NSR administrative permit revisions (including GCPs), TV administrative amendments, TV responsible official notifications, and other submittals required by a permit condition. Refer to Section 4 for instructions, acronyms, and mailing addresses.

For Department use only:		**For Department use only:**
Reviewed by:		Received Date RECEIVED NOV 05 2021 Air Quality Bureau
Permit revision number:		
Date:		
☐ Approved ☐ Completed ☐ Denied		

Section 1: General Information – Required for All Submittals

1	Facility Name: **Eunice Gas Plant**		
2	Preparer/Consultant Name: Adam Erenstein	Title: Principal Consultant	
3	Email: aerenstein@trinityconsultants.com	Phone: (505) 266-6611	
4	Address: 9400 Holly Avenue NE, Bldg. 3, Suite 300, Albuquerque, NM 87122		
5	Air Permit Contact: Samuel Keen	Title: Environmental Engineer	
6	Email: SEKeen@dcpmidstream.com	Phone: (713) 735-3978	
7	Address: 2107 CityWest Blvd., #600, Houston, TX 77042		
8	Check all boxes below for which this submittal applies:	AI #: 595	Permit #: 0440-M11R1; P086R2

☑ NSR Construction Permit (20.2.72 NMAC) ☑ TV Operating Permit (20.2.70 NMAC)	☐ NOI (20.2.73 NMAC) (Sections 2-B, 2-D) ☐ Notice of Exemption (20.2.72.202.B NMAC) (Section 2-F)	☐ PSD Permit (20.2.74 NMAC) ☐ Nonattainment Permit (20.2.79 NMAC)

Section 2: Details of Submittal

Only print and submit the pages necessary for your submittal. Print double sided head-to-toe, flip on short end (tablet). The Permit Section responds to all TV Administrative amendments and responds only to denials of NSR administrative revisions. Courier proof of delivery is required if you want confirmation that the Department received this submittal. Check the box(es) applicable to this submittal:

☐ 2-A(i) & 2-A(ii): Identical Engine or Turbine Replacements

☐ 2-B: Owner, Operator, and Name Changes to NOIs or Construction Permits

☐ 2-C: Ownership or Operational Control Changes for Title V Permits

☒ 2-D: Closing a Facility or Removing Units from a Permit or Canceling an NOI

☐ 2-E: Correct Typographical Error

☐ 2-F: Reporting Exempt Equipment for Minor Construction Permits or for No Permit Required (NPR) Facilities

☐ 2-G: Add Minor NSR Exempt Equipment to Construction Permits for PSD or Nonattainment Sources

☐ 2-H: Title V Responsible Official Designations

☐ 2-I: Submittals to the Permit Programs Manager

Section 3: Certification – Required for All Changes

Section 4: Form Instructions

Section 2-D: Closing a Facility, Removing Units from a Permit, or Canceling an NOI

(Administrative Revision)

Check the appropriate boxes and provide complete information in the table. Closing the permit does not relieve the permittee from any outstanding permit fees.

If any of the units being removed are emission control equipment explain how a permit, federal regulation, or state regulation will not be violated by removal of the control equipment.

☒ Cease operations of the entire facility and cancel the construction permit (20.2.72.219.A(1)(c) NMAC).

Date the facility ceased operating: November 9, 2021

☐ Retire an emissions unit and remove it from the construction permit (20.2.72.219.A(1)(c) NMAC).

Date unit(s) retired:
List all retired unit numbers to be removed from the permit:

☐ Cancel a construction permit for a facility or remove an emissions unit that has not and will not be constructed (20.2.72.219.A(1)(d) NMAC).

☐ Facility (plant) will not be constructed, or	☐ The following units will not be constructed and should be removed from the permit:

☐ Retire an emissions unit and remove it from the TV permit (20.2.70.404.A(1)(c) NMAC).

Date unit(s) retired:
List all retired unit numbers to be removed from the permit:

☒ Voluntary Discontinuation of the TV permit (20.2.70.400.I NMAC).

Date the TV permit was no longer required: November 9, 2021
Explanation: The Eunice Gas Plant will cease operation in response to Settlement Agreement AQB 20-46 (CO).

☐ Cancel a construction permit that is no longer required.

Explanation:

☐ Removal of minor NSR exempt equipment.

Explanation:

☐ Cancel a Notice of Intent (check one or explain):

☐ PER is now below 20.2.73.200 NMAC threshold.	☐ Date the facility ceased operating:

Section 3: Certification – Required for All Submittals

Company Name: DCP Operating Company, LP

I, Scot Millican, hereby certify that the information and data submitted in this application are true and as accurate as possible, to the best of my knowledge and professional expertise and experience.

Signed this 32d day of Nov, 2021, upon my oath or affirmation, before a

notary of the State of New Mexico

Scot Millican — 11-3-21

Signature[1] — Date

Scot Millican — Asst Director

Printed Name — Title

Scribed and sworn before me on this 3 day of November, 2021.

My authorization as a notary of the State of New Mexico expires on the

02 day of March, 2024.

Heidi Stringfellow — 11-3-2021

Notary's Signature — Date

Heidi Stringfellow

Notary's Printed Name

OFFICIAL SEAL
HEIDI STRINGFELLOW
NOTARY PUBLIC
STATE OF NEW MEXICO
My Commission Expires 3-2-24

1 For Title V applications, the signature must be of the Responsible Official as defined in 20.2.70.7.AE NMAC.

November 17, 2021

Certified Mail No. 7019 2280 0000 9680 6987
No return receipt

Samuel Keen
Engineer
DCP Operating Company LP
2107 CityWest Blvd
Suite 600
Houston, TX 77042

Ref: **Air Quality Operating Permit Application No.** P086R3M2
DCP - Eunice Gas Plant
NSR Permit No. 0044M11R2
Agency Interest No. 595 - PRT20210001
AIRS No: 350250044

Dear Samuel Keen:

The Air Quality Bureau is in receipt of DCP Operating Company LP's November 3, 2021 request to voluntarily discontinue the DCP Operating Company LP - Eunice Gas Plant Title V Operating Permit No. P086R3, pursuant to 20.2.70.400.I NMAC. An existing Title V major source may apply for a permit under 20.2.72 NMAC, to obtain federally enforceable conditions that restrict the facility's potential to emit to below Title V Major Source thresholds.

DCP entered into a Settlement Agreement (No. AQB 20-64 (CO)) and Stipulated Final Compliance Order (Final Order) with NMED which was signed on September 9, 2021. Per requirement 116 of the Final Order: "Within 60 days of the effective date of this Final Order, DCP shall permanently cease operations (effective on 11/9/2021) at the Eunice Gas Plant, except as specified in paragraph 112. Within the 60-day period, DCP shall surrender its authority to continue to operate the Eunice Gas Plant under the AQCA by filing: (1) an administrative revision (NSR 0044-M11R2) to the NSR permit removing the SRU and other equipment associated with the gas plant and deleting conditions relating to those units resulting in the closing of Eunice Gas Plant-AI-595, with the exception of conditions, provisions and authority to operate relating to the Amanda Compressor Station (GCP Oil & Gas registration-9442 approved 11/16/2021) and the Eunice Treater (GCP Oil & Gas registration-9441 approved 11/16/2021); and (2) an administrative modification to the Title V permit terminating the permit.

The Air Quality Bureau received DCP Operating Company LP's NSR Permitting actions on November 8, 2021 for Eunice Gas Plant located in Township 21S, Range 36E, Section 5 in Lea County, New Mexico. The approve mentioned permitting actions results in federally enforceable limitations to comply with the stated Settlement Agreement.

The Air Quality Bureau has verified that the actions required to reduce the potential to emit of this facility to below Major Source thresholds have been met. Therefore, the Department has cancelled Title V Operating Permit No. P085-R3 for the Eunice Gas Plant as of November 9, 2021 and DCP Operating Company LP's facility will be removed from the list of major Title V sources in New Mexico.

If you have any questions, please call Joseph Kimbrell at 505-629-2718 or Joseph.Kimbrell@State.NM.US.

Sincerely,

Elizabeth Kuehn
Digitally signed by Elizabeth Kuehn
Date: 2021.11.17 14:11:28 -07'00'

Liz Bisbey-Kuehn
Air Quality Bureau Chief

cc via email: EPA Region VI, 6PD-R, r6airpermits@epa.gov, LeDoux.Erica@epa.gov, Layton.mary@epa.gov
NMED-AQB Compliance & Enforcement Managers via email:
kirby.olson@state.nm.us, Major Source Manager
Melinda Owens, melinda.owens@state.nm.us, Title V Supervisor
Cindy Hollenberg, Cindy.Hollenberg@state.nm.us, Enforcement Manager
Tasha Burns, Tasha.Burns@state.nm.us, Technical Services Manager

NMED Final Cost Evaluation
DCP Operating Company - Linam Ranch Gas Plant

Facility Information

DCP Linam Ranch Gas Plant	**Facility**
Two 1974 Clark TLA-6 2SLB RICE, 2000 hp	**Units**
6 and 7	**Unit IDs**
LEC	**Evaluated Pollution Control**
0.5	**Post-control Emissions Rate (g NOx/bhp-hr)***

*From the 2021.07.06 Dresser-Rand pricing letter included in DCP's 2023.08.28 FFA update. Project scope "supports 0.5 gm NOx/bhp-hr."

Supporting Information

2021	**Calendar year associated with cost estimates**
2000	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 6	Unit 7	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 2,150,000	$ 2,150,000	2021.07.06 Dresser-Rand pricing letter included in 2023.08.28 DCP submittal	Enhanced Combustion
Other Direct Capital Costs 1 ($)	ODC1	$ 50,000	$ 50,000	2021.07.06 Dresser-Rand pricing letter included in 2023.08.28 DCP submittal	Off Engine Modifications
Other Direct Capital Costs 2 ($)	ODC2	$ 130,000	$ 130,000	2021.07.06 Dresser-Rand pricing letter included in 2023.08.28 DCP submittal	Exhaust Aftertreatment
Indirect Capital Costs ($)	IDC	$ 720,000	$ 720,000	2021.07.06 Dresser-Rand pricing letter included in 2023.08.28 DCP submittal	Optional Items/Systems
Total Capital Costs - Direct ($)	TCC	$ 3,050,000	$ 3,050,000	-	PEC + ODC1 + ODC2 + IDC; 2023.07.23 email included in DCP's 2023.08.28 FFA update suggests adding 20% for inflation; adjusted to 2024$ using CEPCI instead
Additional Capital ($)	AC	$ -	$ -	-	
Total Capital Investment ($)	TCI	$ 3,050,000	$ 3,050,000	-	TCC + AC
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	DCP did not provide a company-specific rate
Useful Life (yr)	Y	20	20	Based on default values from the EPA Air Pollution Control Cost Manual	Consistent with other FFAs
Capital Recovery Factor	CRF	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 299,181	$ 299,181	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	-	Incremental O&M of a LEC retrofit is expected to be negligible
Other Indirect Annual Costs ($/yr)	OAC	$ 122,000	$ 122,000	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 421,181	$ 421,181	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	96%	96%	-	(Current actual emission rate - Post-control emission rate)/Current actual emission rate
Baseline Actual NOx Emissions (ton/yr)	BAE	33.5	37.4	CY 2023 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by DCP
Projected Actual Emissions (ton/yr)	PAE	33.5	37.4	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	32.2	36.0	-	PAE x Eff
2021$ Cost Effectiveness ($/ton)	**CE1**	**$ 13,082**	**$ 11,714**	-	TAC/ER; TCI provided by Dresser-Rand in July 2021 so assumed in 2021$
Price Index	PI	1.13	1.13	-	2024 CEPCI* / 2021 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 14,782**	**$ 13,237**	-	CE1 x PI

NMED Final Cost Evaluation
DCP Operating Company - Linam Ranch Gas Plant

Facility Information

DCP Linam Ranch Gas Plant	**Facility**
Four 1951 Clark HBA-6 2SLB RICE, 1267 hp	**Units**
8, 9, 10, and 11	**Unit IDs**
LEC	**Evaluated Pollution Control**
0.5	**Post-control Emissions Rate (g NOx/bhp-hr)***

*From the 2021.07.06 Dresser-Rand pricing letter included in DCP's 2023.08.28 FFA update. Project scope "supports 0.5 gm NOx/bhp-hr."

Supporting Information

2021	**Calendar year associated with cost estimates**
1267	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 8	Unit 9	Unit 10	Unit 11	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 2,150,000	$ 2,150,000	$ 2,150,000	$ 2,150,000	2021.07.06 Dresser-Rand pricing letter included in 2023.08.28 DCP submittal	Enhanced Combustion
Other Direct Capital Costs 1 ($)	ODC1	$ 50,000	$ 50,000	$ 50,000	$ 50,000	2021.07.06 Dresser-Rand pricing letter included in 2023.08.28 DCP submittal	Off Engine Modifications
Other Direct Capital Costs 2 ($)	ODC2	$ 130,000	$ 130,000	$ 130,000	$ 130,000	2021.07.06 Dresser-Rand pricing letter included in 2023.08.28 DCP submittal	Exhaust Aftertreatment
Indirect Capital Costs ($)	IDC	$ 720,000	$ 720,000	$ 720,000	$ 720,000	2021.07.06 Dresser-Rand pricing letter included in 2023.08.28 DCP submittal	Optional Items/Systems
Total Capital Costs - Direct ($)	TCC	$ 3,050,000	$ 3,050,000	$ 3,050,000	$ 3,050,000	-	PEC + ODC1 + ODC2 + IDC; 2023.07.23 email included in DCP's 2023.08.28 FFA update suggests adding 20% for inflation; adjusted to 2024$ using CEPCI instead
Additional Capital ($)	AC	$ -	$ -	$ -	$ -	-	
Total Capital Investment ($)	TCI	$ 3,050,000	$ 3,050,000	$ 3,050,000	$ 3,050,000	-	TCC + AC
Interest Rate (%)	R	7.50%	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	DCP did not provide a company-specific rate
Useful Life (yr)	Y	20	20	20	20	Based on default values from the EPA Air Pollution Control Cost Manual	Consistent with other FFAs
Capital Recovery Factor	CRF	0.0981	0.0981	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 299,181	$ 299,181	$ 299,181	$ 299,181	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	$ -	$ -	-	Incremental O&M of a LEC retrofit is expected to be negligible
Other Indirect Annual Costs ($/yr)	OAC	$ 122,000	$ 122,000	$ 122,000	$ 122,000	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 421,181	$ 421,181	$ 421,181	$ 421,181	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	92%	92%	95%	85%	-	(Current actual emission rate - Post-control emission rate)/Current actual emission rate
Baseline Actual NOx Emissions (ton/yr)	BAE	34.5	34.5	35.0	23.4	CY 2022/2023 emissions testing and average operating hours (CY 2016 - 2021)	Data for Units 10 and 11 used as a surrogate for Units 8 and 9
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	-	Not requested by DCP
Projected Actual Emissions (ton/yr)	PAE	34.5	34.5	35.0	23.4	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	31.9	31.9	33.2	19.8	-	PAE x Eff
2021$ Cost Effectiveness ($/ton)	**CE1**	**$ 13,222**	**$ 13,222**	**$ 12,678**	**$ 21,223**	-	TAC/ER; TCI provided by Dresser-Rand in July 2021 so assumed in 2021$
Price Index	PI	1.13	1.13	1.13	1.13	-	2024 CEPCI* / 2021 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 14,941**	**$ 14,941**	**$ 14,326**	**$ 23,982**	-	CE1 x PI

NMED Final Cost Evaluation
DCP Operating Company - Linam Ranch Gas Plant

Facility Information

DCP Linam Ranch Gas Plant	**Facility**
Two 1974 Clark TLA-6 2SLB RICE, 2000 hp	**Units**
6 and 7	**Unit IDs**
Replacement with new RICE	**Evaluated Pollution Control**
0.3	**Post-control Emissions Rate (g NOx/bhp-hr)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired spark ignited RICE >= 1875 bhp

Supporting Information

2020	**Calendar year associated with cost estimates**
2000	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 6	Unit 7	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 6,454,000	$ 6,454,000	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $3227/hp cost metric as DCP did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered RICE
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	DCP did not provide a company-specific rate
Useful Life (yr)	Y	30	30	ERG experience based on discussions with RICE manufacturers	
Capital Recovery Factor	CRF	0.0847	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 546,468	$ 546,468	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	-	Incremental O&M reasonably negligible
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 546,468	$ 546,468	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	98%	98%	-	(Current actual emission rate - Post-control emission rate)/Current actual emission rate
Baseline Actual NOx Emissions (ton/yr)	BAE	33.5	37.4	CY 2023 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by DCP
Projected Actual Emissions (ton/yr)	PAE	33.5	37.4	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	32.7	36.5	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 16,712**	**$ 14,963**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 and thus assumed costs are in 2020$
Price Index	PI	1.34	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 22,395**	**$ 20,050**	-	CE1 x PI

NMED Final Cost Evaluation
DCP Operating Company - Linam Ranch Gas Plant

Facility Information

DCP Linam Ranch Gas Plant	**Facility**
Four 1951 Clark HBA-6 2SLB RICE, 1267 hp	**Units**
8, 9, 10, and 11	**Unit IDs**
Replacement with new RICE	**Evaluated Pollution Control**
0.5	**Post-control Emissions Rate (g NOx/bhp-hr)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired spark ignited RICE >500 and <1875 bhp

Supporting Information

2020	**Calendar year associated with cost estimates**
1267	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 8	Unit 9	Unit 10	Unit 11	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 4,088,609	$ 4,088,609	$ 4,088,609	$ 4,088,609	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $3227/hp cost metric as DCP did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered RICE.
Interest Rate (%)	R	7.50%	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	DCP did not provide a company-specific rate
Useful Life (yr)	Y	30	30	30	30	ERG experience based on discussions with RICE manufacturers	
Capital Recovery Factor	CRF	0.0847	0.0847	0.0847	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 346,188	$ 346,188	$ 346,188	$ 346,188	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	$ -	$ -	-	Incremental O&M reasonably negligible
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 346,188	$ 346,188	$ 346,188	$ 346,188	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	92%	92%	95%	85%	-	(Current actual emission rate - Post-control emission rate)/Current actual emission rate
Baseline Actual NOx Emissions (ton/yr)	BAE	34.5	34.5	35.0	23.4	CY 2022/2023 emissions testing and average operating hours (CY 2016 - 2021)	Data for Units 10 and 11 used as a surrogate for Units 8 and 9
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	-	Not requested by DCP
Projected Actual Emissions (ton/yr)	PAE	34.5	34.5	35.0	23.4	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	31.9	31.9	33.2	19.8	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 10,868**	**$ 10,868**	**$ 10,420**	**$ 17,444**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 and thus assumed costs are in 2020$
Price Index	PI	1.34	1.34	1.34	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 14,562**	**$ 14,562**	**$ 13,963**	**$ 23,375**	-	CE1 x PI

NMED Final Cost Evaluation
DCP Operating Company - Linam Ranch Gas Plant

Facility Information

DCP Linam Ranch Gas Plant	**Facility**
One 1995 Solar T-70 CT, 10702 hp	**Units**
29	**Unit IDs**
SCR	**Evaluated Pollution Control***

*2023.08.28 Email from DCP states that upgrades/controls have already been installed on Unit 29 for compliance with 20.2.50 NMAC. This evaluation is of the incremental emissions reductions that would be achieved by adding SCR.

Supporting Information

2024	**Calendar year associated with cost estimates**
10702	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 29	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 4,008,496	EPA SCR Tool (2024$)	
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	DCP did not provide a company-specific rate
Useful Life (yr)	Y	20	EPA default	
Capital Recovery Factor	CRF	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 393,202	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 68,400	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 2,869	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 464,471	-	ACC + OMC
NOx Control Efficiency (%)	Eff	80%	EPA SCR Tool	Consistent with EPA and industry documentation
Baseline Actual NOx Emissions (ton/yr)	BAE	4.7	CY 2023 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by DCP
Projected Actual Emissions (ton/yr)	PAE	4.7	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	3.7	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 124,269**	-	TAC/ER

NMED Final Cost Evaluation
DCP Operating Company - Linam Ranch Gas Plant

Facility Information

DCP Linam Ranch Gas Plant	**Facility**
One 1995 Solar Taurus T-70 CT, 9900 hp	**Units**
30	**Unit IDs**
SCR	**Evaluated Pollution Control***

*2023.08.28 Email from DCP states that upgrades/controls have already been installed on Unit 30 for compliance with 20.2.50 NMAC. This evaluation is of the incremental emissions reductions that would be achieved by adding SCR.

Supporting Information

2024	**Calendar year associated with cost estimates**
9900	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 30	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 3,884,912	EPA SCR Tool (2024$)	
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	DCP did not provide a company-specific rate
Useful Life (yr)	Y	20	EPA default	
Capital Recovery Factor	CRF	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 381,080	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 58,181	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 2,861	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 442,122	-	ACC + OMC
NOx Control Efficiency (%)	Eff	80%	EPA SCR Tool	Consistent with EPA and industry documentation.
Baseline Actual NOx Emissions (ton/yr)	BAE	7.9	CY 2023 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by DCP
Projected Actual Emissions (ton/yr)	PAE	7.9	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	6.4	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 69,548**	-	TAC/ER

NMED Final Cost Evaluation
DCP Operating Company - Linam Ranch Gas Plant

Facility Information

DCP Linam Ranch Gas Plant	**Facility**
One 1995 Solar T-4700 CT, 4700 hp	**Units**
31	**Unit IDs**
SCR	**Evaluated Pollution Control***

*2024.01.23 Email from DCP states that upgrades to Unit 31 were completed 10/29/23. This evaluation is of the incremental emissions reductions that would be achieved by adding SCR.

Supporting Information

2024	**Calendar year associated with cost estimates**
4700	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 31	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 2,468,155	EPA SCR Tool (2024$)	
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	DCP did not provide a company-specific rate
Useful Life (yr)	Y	20	EPA default	
Capital Recovery Factor	CRF	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 242,107	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 36,435	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 2,776	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 281,318	-	ACC + OMC
NOx Control Efficiency (%)	Eff	80%	EPA SCR Tool	Consistent with EPA and industry documentation.
Baseline Actual NOx Emissions (ton/yr)	BAE	12.8	CY 2023 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by DCP
Projected Actual Emissions (ton/yr)	PAE	12.8	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	10.3	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 27,433**	-	TAC/ER

NMED Final Cost Evaluation
DCP Operating Company - Linam Ranch Gas Plant

Facility Information

DCP Linam Ranch Gas Plant	**Facility**
One 1979 Solar T-4000 CT, 3961 hp	**Units**
32B	**Unit IDs**
SCR	**Evaluated Pollution Control***

*2023.08.28 Email from DCP states that upgrades/controls (DLN) will be installed on Unit 32B to ensure compliance with 20.2.50 NMAC. 2024.02.05 Email from DCP states that the project is out for bid and is expected to be completed by the end of 2025. Therefore, this evaluation assumes DLN has already been installed and is of the incremental emissions reductions that would be achieved by adding SCR.

Supporting Information

2024	**Calendar year associated with cost estimates**
3961	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 32B	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 2,441,923	EPA SCR Tool (2024$)	
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	DCP did not provide a company-specific rate
Useful Life (yr)	Y	20	EPA default	
Capital Recovery Factor	CRF	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 239,534	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 30,374	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 2,775	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 272,682	-	ACC + OMC
NOx Control Efficiency (%)	Eff	80%	EPA SCR Tool	Consistent with EPA and industry documentation.
Baseline Actual NOx Emissions (ton/yr)	BAE	11.5	CY 2022 emissions testing and average operating hours (CY 2016 - 2021)	Assumes 25 ppm DLN has already been installed
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by DCP
Projected Actual Emissions (ton/yr)	PAE	11.5	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	9.2	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 29,766**	-	TAC/ER

NMED Final Cost Evaluation
DCP Operating Company - Linam Ranch Gas Plant

Facility Information

DCP Linam Ranch Gas Plant	**Facility**
One 1995 Solar T-70 CT, 10702 hp	**Units**
29	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
15.0	**Post-control Emissions Rate (ppm NOx)***

*2023.08.28 Email from DCP states that upgrades/controls have already been installed on Unit 29 for compliance with 20.2.50 NMAC. This evaluation is of the incremental emissions reductions that would be achieved by replacing Unit 29 with a new turbine meeting the emissions standards in 20.2.50 NMAC for new NG-fired turbines >=4,000 hp and <15,900 hp.

Supporting Information

2020	**Calendar year associated with cost estimates**
10702	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 29	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 25,877,436	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $2418/hp cost metric as DCP did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered CT.
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	DCP did not provide a company-specific rate
Useful Life (yr)	Y	30	ERG experience based on discussions with CT manufacturers	
Capital Recovery Factor	CRF	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 2,191,074	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	-	Incremental O&M reasonably negligible since existing unit already has SoLoNOx
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 2,191,074	-	ACC + OMC
NOx Control Efficiency (%)	Eff	-199%	-	(Current actual emission rate - Post-control emission rate)/Current actual emission rate; Negative control efficiency and cost effectiveness due to current controlled emission rate being less than target rate of 15 ppm.
Baseline Actual NOx Emissions (ton/yr)	BAE	4.7	CY 2023 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by DCP
Projected Actual Emissions (ton/yr)	PAE	4.7	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	-9.3	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**-$235,192**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 and thus assumed costs are in 2020$
Price Index	PI	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**-$315,157**	-	CE1 x PI

NMED Final Cost Evaluation
DCP Operating Company - Linam Ranch Gas Plant

Facility Information

DCP Linam Ranch Gas Plant	**Facility**
One 1995 Solar Taurus T-70 CT, 9900 hp	**Units**
30	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
15.0	**Post-control Emissions Rate (ppm NOx)***

*2023.08.28 Email from DCP states that upgrades/controls have already been installed on Unit 30 for compliance with 20.2.50 NMAC. This evaluation is of the incremental emissions reductions that would be achieved by replacing Unit 30 with a new turbine meeting the emissions standards in 20.2.50 NMAC for new NG-fired turbines >=4,000 hp and <15,900 hp.

Supporting Information

2020	**Calendar year associated with cost estimates**
9900	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 30	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 23,938,200	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $2418/hp cost metric as DCP did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered CT.
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	DCP did not provide a company-specific rate
Useful Life (yr)	Y	30	ERG experience based on discussions with CT manufacturers	
Capital Recovery Factor	CRF	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 2,026,877	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	-	Incremental O&M reasonably negligible since existing unit already has SoLoNOx
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 2,026,877	-	ACC + OMC
NOx Control Efficiency (%)	Eff	-25%	-	(Current actual emission rate - Post-control emission rate)/Current actual emission rate; Negative control efficiency and cost effectiveness due to current controlled emission rate being less than target rate of 15 ppm.
Baseline Actual NOx Emissions (ton/yr)	BAE	7.9	CY 2023 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by DCP
Projected Actual Emissions (ton/yr)	PAE	7.9	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	-2.0	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**-$1,024,549**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 and thus assumed costs are in 2020$
Price Index	PI	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**-$1,372,896**	-	CE1 x PI

NMED Final Cost Evaluation
DCP Operating Company - Linam Ranch Gas Plant

Facility Information

DCP Linam Ranch Gas Plant	**Facility**
One 1995 Solar T-4700 CT, 4700 hp	**Units**
31	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
15.0	**Post-control Emissions Rate (ppm NOx)***

*2024.01.23 Email from DCP states that upgrades to Unit 31 were completed 10/29/23. This evaluation is of the incremental emissions reductions that would be achieved by replacing Unit 31 with a new turbine meeting the emissions standards in 20.2.50 NMAC for new NG-fired turbines >=4,000 hp and <15,900 hp.

Supporting Information

2020	**Calendar year associated with cost estimates**
4700	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 31	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 11,364,600	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $2418/hp cost metric as DCP did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered CT.
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	DCP did not provide a company-specific rate
Useful Life (yr)	Y	30	ERG experience based on discussions with CT manufacturers	
Capital Recovery Factor	CRF	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 962,255	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	-	Incremental O&M reasonably negligible since existing unit already has SoLoNOx
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 962,255	-	ACC + OMC
NOx Control Efficiency (%)	Eff	20%	-	(Current actual emission rate - Post-control emission rate)/Current actual emission rate
Baseline Actual NOx Emissions (ton/yr)	BAE	12.8	CY 2023 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by DCP
Projected Actual Emissions (ton/yr)	PAE	12.8	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	2.6	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 373,742**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 and thus assumed costs are in 2020$
Price Index	PI	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 500,815**	-	CE1 x PI

NMED Final Cost Evaluation
DCP Operating Company - Linam Ranch Gas Plant

Facility Information

DCP Linam Ranch Gas Plant	**Facility**
One 1979 Solar T-4000 CT, 3961 hp	**Units**
32B	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
25.0	**Post-control Emissions Rate (ppm NOx)***

*2023.08.28 Email from DCP states that upgrades/controls (DLN) will be installed on Unit 32B to ensure compliance with 20.2.50 NMAC. 2024.02.05 Email from DCP states that the project is out for bid and is expected to be completed by the end of 2025. Therefore, this evaluation assumes DLN has already been installed and is of the incremental emissions reductions that would be achieved by replacing Unit 32B with a new turbine. Post-control emissions rate of 25 ppm is consistent with manufacturer specifications for similar, new CT equipped with DLN.

Supporting Information

2020	**Calendar year associated with cost estimates**
3961	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 32B	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 9,577,698	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $2418/hp cost metric as DCP did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered CT.
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	DCP did not provide a company-specific rate
Useful Life (yr)	Y	30	ERG experience based on discussions with CT manufacturers	
Capital Recovery Factor	CRF	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 810,956	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	-	Incremental O&M reasonably negligible since existing unit already has SoLoNOx
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 810,956	-	ACC + OMC
NOx Control Efficiency (%)	Eff	0%	-	(Current actual emission rate - Post-control emission rate)/Current actual emission rate
Baseline Actual NOx Emissions (ton/yr)	BAE	11.5	CY 2022 emissions testing and average operating hours (CY 2016 - 2021)	Assumes 25 ppm DLN has already been installed
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by DCP
Projected Actual Emissions (ton/yr)	PAE	11.5	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	0.0	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**#DIV/0!**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 and thus assumed costs are in 2020$
Price Index	PI	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**#DIV/0!**	-	CE1 x PI

NMED Final Cost Evaluation
DCP Operating Company - Linam Ranch Gas Plant

Facility Information

DCP Linam Ranch Gas Plant	**Facility**
2 1974 Clark TLA-6 2SLB RICE, 2,000 hp 4 1954 Clark HBA-6 2SLB RICE, 1,267 hp 1 1995 Solar T-70 CT, 10,702 hp 1 1995 Solar T-70 CT, 9,900 hp 1 1995 Solar T-4700 CT, 4,700 hp 1 1995 Solar T-4000 CT, 3,961 hp	**Units**
Unit 6, 7, 8, 9, 10, 11, 29, 30, 31, and 32B	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (lb/hr)**

Additional Information

2023	Calendar year associated with cost estimates
Varies	Maximum Power Output (hp/unit)
10	Number of units that will be replaced (for appropriation of transmission and substation costs)

Economic Evaluation

Cost Component		Unit 6	Unit 7	Unit 8	Unit 9	Unit 10	Unit 11	Unit 29	Unit 30	Unit 31	Unit 32B	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCC
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCC
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCC
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCC
Total Capital Costs - Direct ($)	TCC	$ 4,000,000	$ 4,000,000	$ 2,534,000	$ 2,534,000	$ 2,534,000	$ 2,534,000	$ 21,404,000	$ 19,800,000	$ 9,400,000	$ 7,922,000	2023.08.28 DCP submittal	$2,000/HP (includes labor and on-site electrical infrastructure downstream of the substation); Total cost of $90M in DCP's 2023.08.28 submittal includes unit 28 (7,700 hp) which is not subject to regional haze.
Additional Capital ($)	AC	$ 2,800,000	$ 2,800,000	$ 2,800,000	$ 2,800,000	$ 2,800,000	$ 2,800,000	$ 2,800,000	$ 2,800,000	$ 2,800,000	$ 2,800,000	2023.08.28 DCP submittal	Transmission and substation upgrades
Total Capital Investment ($)	TCI	$ 6,800,000	$ 6,800,000	$ 5,334,000	$ 5,334,000	$ 5,334,000	$ 5,334,000	$ 24,204,000	$ 22,600,000	$ 12,200,000	$ 10,722,000	-	TCC + AC
Interest Rate (%)	R	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	DCP did not provide a company-specific rate
Useful Life (yr)	Y	25	25	25	25	25	25	25	25	25	25	Consistent with other FFAs	
Capital Recovery Factor	CRF	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 610,033	$ 610,033	$ 478,517	$ 478,517	$ 478,517	$ 478,517	$ 2,171,357	$ 2,027,461	$ 1,094,470	$ 961,878	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 559,860	$ 559,860	$ 354,671	$ 354,671	$ 354,671	$ 354,671	$ 2,995,812	$ 2,771,308	$ 1,315,671	$ 1,108,803	-	AED + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 1,119,720	$ 1,119,720	$ 709,343	$ 709,343	$ 709,343	$ 709,343	$ 5,991,623	$ 5,542,616	$ 2,631,343	$ 2,217,606	2023.08.28 DCP submittal	Future electricity costs apportioned by each unit's share of total HP
Associated non-electricity O&M ($/yr)	AOM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Engineering judgement	Assumed to be negligible
Annual Fuel Credit ($/yr)	AFC	$ (559,860)	$ (559,860)	$ (354,671)	$ (354,671)	$ (354,671)	$ (354,671)	$ (2,995,812)	$ (2,771,308)	$ (1,315,671)	$ (1,108,803)	ERG calculation	Assumed equal to 50% of AED
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 1,169,893	$ 1,169,893	$ 833,188	$ 833,188	$ 833,188	$ 833,188	$ 5,167,169	$ 4,798,769	$ 2,410,142	$ 2,070,681	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	33.5	37.4	34.5	34.5	35.0	23.4	4.7	7.9	12.8	11.5	CY 2022/2023 emissions testing and average operating hours (CY 2016 - 2021)	BAE for Unit 32B assumes 25 ppm DLN has already been installed
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-	Not requested by DCP
Projected Actual Emissions (ton/yr)	PAE	33.5	37.4	34.5	34.5	35.0	23.4	4.7	7.9	12.8	11.5	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	33.5	37.4	34.5	34.5	35.0	23.4	4.7	7.9	12.8	11.5	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 34,972**	**$ 31,303**	**$ 24,132**	**$ 24,132**	**$ 23,774**	**$ 35,662**	**$ 1,105,976**	**$ 603,898**	**$ 188,019**	**$ 180,828**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 34,972**	**$ 31,303**	**$ 24,132**	**$ 24,132**	**$ 23,774**	**$ 35,662**	**$ 1,105,976**	**$ 603,898**	**$ 188,019**	**$ 180,828**	-	CE1 x PI

NMED Final Cost Evaluation
DCP Operating Company - Linam Ranch Gas Plant

Unit 29: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	77.6	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	638,337,148	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3730	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365	days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.0425	lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0085	lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050		Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
			Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours		
Estimated SCR equipment life	20	Years*	Gas temperature at the SCR inlet (T)	650 °F
Base case fuel gas volumetric flow rate factor (Q_{fuel})				UNK ft^3/min-MMBtu/hour
Concentration of reagent as stored (C_{stored})	29	percent*		
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*		
Number of days reagent is stored ($t_{storage}$)	14	days		

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

* For industrial boilers, the typical equipment life is between 20 and 25 years.

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 29: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	78	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	659,336,566	scf/Year	
Actual Annual fuel consumption (Mactual) =		638,337,148	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.968	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8481	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	2.64	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	11.19	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.15		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	276.54	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	1	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	4	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	0	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	200	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	45.94	kW

Unit 29: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$4,008,496	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$68,400 in 2024 dollars
Indirect Annual Costs (IDAC) =	$396,102 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$464,502 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$20,042 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$2,120 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$38,962 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$7,275 in 2024 dollars
Direct Annual Cost =		$68,400 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,869 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$393,233 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$396,102 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$464,502 per year in 2024 dollars
NOx Removed =	11 tons/year
Cost Effectiveness =	$41,492 per ton of NOx removed in 2024 dollars

Unit 30: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	73.95	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	502,157,081	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 3730 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.031	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0061	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024			
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI
Annual Interest Rate (i)	7.5	Percent		
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia		
Electricity ($Cost_{elect}$)	0.1000	$/kWh		
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	60.00	$/hour (including benefits)*		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

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Unit 30: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	74	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	628,323,957	scf/Year
Actual Annual fuel consumption (Mactual) =		502,157,081	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.799	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7001	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	1.82	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	6.36	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.15	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	262.38	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole
Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	1	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	2	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	0	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	200	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	43.78	kW

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Unit 30: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$3,884,912	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$58,181 in 2024 dollars
Indirect Annual Costs (IDAC) =	$383,971 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$442,152 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$19,425 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$1,204 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$30,650 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$6,902 in 2024 dollars
Direct Annual Cost =		$58,181 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,861 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$381,110 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$383,971 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$442,152 per year in 2024 dollars
NOx Removed =	6 tons/year
Cost Effectiveness =	$69,555 per ton of NOx removed in 2024 dollars

Unit 31: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	36.8	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	305,643,453	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 3730 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.0813	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0163	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024			
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI
Annual Interest Rate (i)	7.5	Percent		
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia		
Electricity ($Cost_{elect}$)	0.1000	$/kWh		
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	60.00	$/hour (including benefits)*		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

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Unit 31: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	37	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	312,675,073	scf/Year
Actual Annual fuel consumption (Mactual) =		305,643,453	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.978	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8563	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	2.39	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	10.24	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.15	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	133.02	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole
Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	1	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	3	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	0	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	200	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	21.79	kW

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Unit 31: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,468,155	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$36,435 in 2024 dollars
Indirect Annual Costs (IDAC) =	$244,902 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$281,337 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,341 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$1,940 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$18,655 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$3,500 in 2024 dollars
Direct Annual Cost =		$36,435 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,776 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$242,126 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$244,902 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$281,337 per year in 2024 dollars
NOx Removed =	10 tons/year
Cost Effectiveness =	$27,471 per ton of NOx removed in 2024 dollars

Unit 32B: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	36.2	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	212,284,384	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3730	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.1046	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0209	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

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Unit 32B: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	36	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	307,577,110	scf/Year	
Actual Annual fuel consumption (Mactual) =		212,284,384	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.690	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6046	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	3.03	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	9.16	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.15		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	131.97	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole
Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	1	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	4	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	1	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	200	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	21.43	kW

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Unit 32B: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,441,923	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$30,374 in 2024 dollars
Indirect Annual Costs (IDAC) =	$242,327 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$272,701 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,210 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$1,735 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$12,957 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$3,472 in 2024 dollars
Direct Annual Cost =		$30,374 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,775 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$239,553 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$242,327 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$272,701 per year in 2024 dollars
NOx Removed =	9 tons/year
Cost Effectiveness =	$29,767 per ton of NOx removed in 2024 dollars

REGIONAL HAZE FOUR-FACTOR ANALYSIS

DCP Operating Company, LP
Linam Ranch Gas Plant

Prepared By:

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1. EXECUTIVE SUMMARY

In the 1977 amendments to the Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

> *(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A).* This is known as a four-factor analysis.
>
> *(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B).* The uniform rate of progress or improvement is sometimes referred to as the glidepath and is part of the state's Long-Term Strategy (LTS).

The second implementation planning period (2018-2028) for national regional haze efforts is currently underway. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural or biogenic and manmade or anthropogenic sources of emissions. Using a Photochemical Grid Model (PGM), the Western Region Air Partnership (WRAP), in coordination with the EPA, is tasked with comparing anthropogenic source contributions against natural background concentrations.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for major sources and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I area. From this analysis, 24 facilities were identified by the NMED. On July 18, 2019 the NMED informed DCP Operating Company, LP (DCP), that its Linam Ranch Gas Plant (Linam) was identified as one of the sources possibly contributing to regional haze at nearby Class I areas.

In coordination with guidance provided by WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. The NMED's July 18, 2019 notification letter to DCP specifies that any equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The equipment at the facility

subject to the analysis, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant are reported in Table 1.

Table 1. Summary of Equipment and Applicability to a Four-Factor Analysis

Equipment	NO_X Hourly PTE (lb/hr)	NO_X Annual PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
Clark TLA-6 2SLB RICE (Unit 6)	39.29		Yes	0.010		No
Clark TLA-6 2SLB RICE (Unit 7)	39.29		Yes	0.010		No
Clark HBA-6 2SLB RICE (Unit 8)	47.49	566.08	Yes	0.0070	0.12	No
Clark HBA-6 2SLB RICE (Unit 9)	47.49		Yes	0.0070		No
Clark HBA-6 2SLB RICE (Unit 10)	47.49		Yes	0.0070		No
Clark HBA-6 2SLB RICE (Unit 11)	47.49		Yes	0.0070		No
Solar Centaur T-70 Turbine (Unit 29)	11.82	51.78	Yes	0.26	1.16	No
Solar Centaur T-70 Turbine (Unit 30)	11.26	49.32	Yes	0.25	1.10	No
Solar Centaur T-4700 Turbine (Unit 31)	26.03	114.01	Yes	0.13	0.55	No
Solar Centaur T-4000 Turbine (Unit 32B)	23.72	103.88	Yes	0.12	0.54	No
ESD Flare (Unit 4A)	14.80	0.88	No*	9301.45	4.13	No*

* Pursuant to NMED Guidance received on 9/23/2019, the Four Factor Analysis is to be completed for steady state sources of emissions only; as such, emissions from SSM/M activities are not subject to a Four Factor Analysis.

Once the applicability of the four factor analysis has been determined for process equipment and pollutants, potential retrofit control technologies must be identified. In accordance with 40 CFR 51 Appendix Y and at the recommendation of the NMED[1], potentially applicable emissions reduction technologies are informed by reviewing the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC). In order to determine the most relevant and current retrofit controls available, the RBLC was queried for the previous ten years. Summaries of the result of this search are provided and discussed under Section 2 of this report. The facility engineers then reviewed the list of available retrofit technologies and performed a technical feasibility assessment for each control option. The four-factor analysis is then conducted for those controls that are technically feasible.

[1] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

At Linam, the six (6) natural gas-fired two-stroke lean burn engines (Units 6, 7, 8, 9, 10 & 11) and four (4) combustion turbines (Units 29, 30, 31 & 32B) are subject to this four-factor analysis based on NO_X emissions. No units are subject based on SO_2 emissions. The turbines are either Solar Centaur T-70, T-4000 or T-4700 units. Manufacture dates for these units range from 1979 to 1995. The engines are either Clark TLA-6 or HBA-6 units. Manufacture dates range from 1951 to 1974 for the engines.

2.1. NATURAL GAS-FIRED COMBUSTION TURBINES

2.1.1. Combustion Turbine Background

A gas turbine is an internal combustion engine that operates with a rotary, rather than reciprocating, motion and is composed of three primary components: a compressor, a combustor, and a power turbine. The compressor draws in ambient air and compresses it up to 30 times the ambient pressure, then directs it into the combustor where fuel is introduced, ignited, and burned. Exhaust gas from the combustor is then diluted with additional air and sent to the power turbine at temperatures up to 2600 °F. The hot exhaust gas expands in the power turbine section, generating energy in the form of shaft horsepower.[2]

The treatment of the exhaust gases exiting the turbine dictate the cycle designation of these units. The heat content can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).[3] The units at Linam are regenerative cycle turbines, which are essentially simple cycle gas turbine with an added heat exchanger.

NO_X is formed via three fundamentally different mechanisms. The principle NO_X formation mechanism, thermal NO_X, arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion. Most thermal NO_X forms in the highest temperature regions of the combustion chamber. The second NO_X formation mechanism, fuel NO_X, arises from the evolution and reaction of fuel bound nitrogen compounds with oxygen. The final NO_X formation mechanism, prompt NO_X, arises from early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The significance of prompt NO_X is negligible in comparison to thermal and fuel NO_X. Fuel NO_X will also be negligible for Linam's turbines assessed here, as these combustion turbines fire natural gas, which contains a negligible amount of nitrogen compounds. Therefore, this analysis will focus on thermal NO_X.

2.1.2. Potential NO_X Controls for a Combustion Turbine

There are three general methods of controlling NO_X emission from gas turbines; (1) wet controls, which use steam or water injection to reduce combustion temperatures and NO_X formation, (2) dry controls that use

[2] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"
[3] Ibid.

advanced combustor design to suppress NO_X formation, and (3) post-combustion, catalytic controls to selectively reduce NO_X.[4]

The retrofit control equipment that was identified for combustion turbines during a comprehensive review of the RBLC, available literature, and manufacturer's input is reported in Table 2. A more detailed table summarizing the RBLC review is provided in Appendix A. A detailed discussion, including a description, the technical feasibility, and the anticipated performance of each control is provided below.

Table 2. Potential Control Options for Combustion Turbines

Control Equipment	Technically Feasible?	NO_X Control Efficiency
Good Combustion Practices	Yes	Base Case
Improved Combustion Technology	Yes	vendor ppm guarantee
Water/Steam Injection	No	N/A
Selective Catalytic Reduction	Yes	70%

2.1.2.1. Good Combustion Practices

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from combustion turbines; therefore, it has been determined that this method of NO_X control is feasible for the units at Linam. However, these good combustion practices are currently in use at Linam, as required by various conditions in its Title V and NSR permits. Accordingly, no further assessment of these control practices has been included in this report.

2.1.2.2. Improved Combustion Technology

The improved combustion technology control option, commonly referred to as Dry Low NO_X (DLN) control, also seeks to reduce the combustion temperature and residence time of fuel in the combustor (thereby decreasing NO_X formation) by increasing the air-to-fuel ratio in the combustion chamber. There are several levels of improvements that can be made to the combustion chamber, which achieve this NO_X control at varying levels. Based on communications with Solar, the DLN control option involves a thorough overhaul of the combustion section of the turbine, including replacement of the air and fuel injection nozzles, modifications to or complete replacement of the combustion chamber, and replacement of the electrical control system for the unit. Solar's specific technology, SoLoNO$_X$ utilizes lean-premixed combustion technology to ensure an extremely uniform air/fuel mixture and stringently controls the combustion process to prevent undesirable emissions from forming. An overall reduction efficiency of 55% - 80% can be achieved for the turbines located at this facility

[4] Ibid.

using this technology in comparison to permitted PTE. Reduction efficiencies are dependent on, and can vary based on, existing technologies already installed on the facility's units.

Solar has performed numerous retrofits of existing turbines with SoLoNO$_X$ and, even though there are extensive overhaul and implementation costs, the technology is technically feasible. Therefore, a cost analysis will be completed to determine the cost effectiveness per ton of NO$_X$ removed.

2.1.2.3. Water/Steam Injection

Water or steam injection is a control technology for gas turbines that has been demonstrated to effectively suppress NO$_X$ emissions. Injection of steam and water has the effect of increasing the thermal mass by dilution and thereby reducing the peak temperature in the flame zone. There is an additional benefit of absorbing the latent heat of vaporization from the flame zone when water injection is utilized. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.[5]

Steam injection is not discussed as an option for these Solar turbines at Linam because Solar does not manufacture turbines with steam injection technology. Although the Solar turbines are mechanically capable of supporting water injection, Solar has stated that they do not offer water injection retrofits for any of the Centaur 40 conventional combustion line of turbines. This is primarily due to the design of the combustor housing of the conventional Centaur 40. The injectors on this style of combustor intersect directly into the combustor without using direct air flow for the direction of fuel. The style of injector needed to implement water injection technology is referred to by Solar as a Dual Lined Injector. This type of injector introduces fuel laterally into the front of a combustor and utilizes a controlled flow to disperse fuel.

Solar considers the control technique to be antiquated technology in comparison to the other control methods they have available, such as SoLoNO$_X$. Solar has retired this control option and does not recommend water injection be installed to control emissions from their turbine units. Also, Solar stated that if direct modifications are made to the turbine engine or it's supporting hardware to retrofit third party water injection control, then Solar will not uphold any existing warranty to the unit and previous maintenance work done by Solar to the turbines. Combustion turbine units are high capital value assets and this retrofit would create a high risk factor going against manufacturer's recommendation.

Furthermore, per conversations with Solar, approximately 5 gallons per minute (gpm) of de-ionized or de-mineralized water will be needed to properly implement this control. For a continuously operating turbine, this represents a total water usage of approximately 2.6 million gallons per year, per unit, without taking into consideration leaks and evaporative losses that would occur during transport. Securing the availability of such a large quantity of water will be a difficult even without factoring in the necessary de-ionization and de-mineralization treatment.

Although the Solar turbines on site have the potential to be mechanically retrofitted with water injection, the facility also does not have access to sufficient water for this technology. Additionally, based on the high mineral content of water in the Permian Basin, even when filtration techniques are implemented, DCP engineers have determined that continuous water injection poses a high risk for vibrational imbalance on rotating equipment, which may cause critical damage to the equipment and ultimately decrease the equipment life expectancy. For these reasons, DCP has deemed this control technology as technically infeasible for the turbines located at Linam.

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[5] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"

2.1.2.4. Selective Catalytic Reduction Systems

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust downstream of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[6] The chemical reactions for this process are shown in the equations below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O \quad \text{(Equation 1)}$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O \quad \text{(Equation 2)}$$

A SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and an electronic control system. The electronic controls regulate the quantity of reagent injected as a function of turbine load, speed, and temperature, so NO_X emissions reductions can be achieved. The lifespan of the catalyst is primarily determined by poisoning of active sites by flue gas constituent, thermal sintering, or compacting, of active sites due to high temperatures in the reactor, fouling caused by ammonia-sulfur salts and particulate matter in the gas, and erosion due to high gas velocities.[7]

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as ammonia slip. Unreacted ammonia in the exhaust can form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.[8]

In order for the SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 and 850 °F), dependent on the material of the catalyst. Exhaust gas temperatures greater than the upper limit will cause the NO_X and ammonia to pass through the catalyst unreacted.[9] The exhaust temperature of the turbines assessed here is approximately 580 °F.

Assuming that any space limitations can be overcome, SCR is considered a technically feasible control option for the turbines located at Linam. SCR units typically achieve 65% to 90% NO_X reduction, dependent on the exhaust temperature and upstream NO_X concentration. If the NO_X concentration is already low, it can be difficult to achieve these control efficiencies.[10] A cost analysis is completed for SCR using an overall reduction efficiency of 70%.

2.2. NATURAL GAS-FIRED TWO-STROKE LEAN-BURN (2SLB) ENGINES

2.2.1. Two-Stroke Lean-Burn Engines Background

A reciprocating internal combustion engine (RICE) is a device that uses the combustion of fuel and air in an internal chamber to generate a reciprocating motion and convert heat energy into mechanical work. The units use a piston to draw air and fuel into the combustion chamber and compress it. The compressed air/fuel mixture is then ignited, generating combustion in the chamber. The energy of combustion pushes out the piston, turning

[6] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
[7] Ibid.
[8] Ibid.
[9] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"
[10] Ibid.

a crankshaft and producing mechanical work. In the same cycle, the products of combustion remaining in the chamber are released and exhausted from the unit.

Natural gas-fired RICE are separated into multiple design classes, including 2-stroke lean-burn (2SLB), 4-stroke lean-burn (4SLB), and 4-stroke rich-burn (4SRB). The four-stroke design uses four strokes of the piston, or two turns of the crankshaft, to complete the power cycle. The two-stroke design completes the power cycle in a single revolution of the crankshaft. Rich-burn engines are designed to operate close to the stoichiometric, or chemically balanced, air-to-fuel ratio (around 16:1) with exhaust oxygen levels less than 4%, while lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1), with exhaust oxygen levels of 12% or more.[11]

NO_X is formed in reciprocating engines via the same three mechanisms applicable to the turbines:

(1) Thermal NO_X - the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion,
(2) Fuel NO_X - the evolution and reaction of fuel-bound nitrogen compounds with oxygen, and
(3) Prompt NO_X - the early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The Linam engines also use natural gas fuel; therefore, the formation of prompt and fuel NO_X will again be insignificant, and this analysis will focus on thermal NO_X. The rate of NO_X formation through the thermal NO_X mechanism is highly dependent upon the air-to-fuel ratio, combustion temperature, and residence time at the combustion temperature. Maximum thermal NO_X formation occurs near the stoichiometric air-to-fuel mixture ratio because combustion temperatures are greatest at this ratio.[12]

NO_X reduction in natural gas-fired RICE can be accomplished by three general methods, as follows:[13]

(1) Operational control methods, such as adjusting the timing or other operating parameters.
(2) Combustion control techniques, for example reducing the peak flame temperature or introducing inerts that limit initial NO_X formation.
(3) Post-combustion NO_X control technologies, which employ various strategies to chemically reduce NO_X.

The PTE associated with each engine is reported in the facility's New Source Review and Title V permits, as well as summarized in Table 1 of this report.

2.2.2. Potential NO_X Controls for 2SLB Engines

Potential retrofit control options identified for 2SLB RICE were identified via comprehensive review of the RBLC and available technical literature and are summarized in Table 3. A detailed description and discussion of the technical feasibility and anticipated performance of each control is provided below.

[11] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
[12] Ibid.
[13] Ibid.

Table 3. Potential Control Equipment for 2SLB RICE

Control Equipment	Technically Feasible?	NO_X Control Efficiency
Good Combustion Practices and Fuel Selection	**Yes**	**Base Case**
Clean Burn Technology	**No**	**5% - 30%**
Selective Catalytic Reduction	**No**	**N/A**
Non-Selective Catalytic Reduction	**No**	**N/A**

2.2.2.1. Good Combustion Practices and Fuel Selection

By following the same concepts from engineering knowledge, experience, and manufacturer's recommendations referenced above, good combustion practices for operation of engines can be developed and maintained. This is achieved by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection for the 2SLB engines are similar to those identified in this review of the RBLC for the control of NO_X emissions from combustion turbines; therefore, it has been determined that this method of NO_X control is feasible for the 2SLB engines at Linam and these practices are currently in use at Linam, as required by various conditions in its Title V and NSR permit authorizations. Accordingly, no further assessment of these control practices is included in this report.

2.2.2.2. Clean Burn Technology

Clean Burn Technology (CBT) is another term for utilizing combustion mixtures in engines with fuel-lean air-to-fuel ratios. This method of reducing NO_X emissions involves reconfiguring the engines by adding or enhancing an air-to-fuel ratio controller, making the unit capable of operating at more desirable ratios.

Rich-burn engines are normally designed to operate close to the stoichiometric, or chemically balanced, air-to-fuel ratio of 16:1, while lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1). A combustion mixture with a higher air-to-fuel ratio results in reduced NO_X emissions, because using fuel-lean mixtures lowers the combustion temperature by diluting energy input. As noted, 2SLB engines are typically designed to operate at the high air-to-fuel ratios employed in CBT, so by design these units are in general not amenable to an increase in air-to-fuel ratio to receive significant NOx reduction benefits. The technology will also have a negative trade-off through an increase in Carbon Monoxide(CO) emissions; however, further increasing the air-to-fuel ratio in lean-burn engines can decrease the NO_X emissions to some degree.[14]

Additionally, in order to avoid derating the engine, combustion air must be increased at constant fuel flow. To achieve this, the engine will need to be retrofitted with a turbocharger, which forces additional air into the combustion chamber, as well as an automatic air-to-fuel ratio controller.

Many 2SLB engines, such as naturally aspirated engines, do not have identical air-to-fuel ratios in each cylinder, which can result in limited ability to vary the air-to-fuel ratio. To maintain acceptable engine performance at

[14] State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines, State of New Jersey Department of Environmental Protection, 2003.

lean conditions, high energy ignition systems (HEIS) have been developed that promote flame stability at very lean conditions.[15]

2SLB engines are mechanically capable of being retrofit with more sensitive air-to-fuel ratio controllers and running on higher air-to-fuel ratio combustion to control NO_X emissions. However, based on the advanced age, type of engine, and discussion with vendor, DCP has determined that clean burn technology retrofits are physically possible yet deemed technically infeasible for the engines at Linam. The aforementioned available clean burn control technologies are incapable of being retrofit on the existing 70-year-old engines on site.

2.2.2.3. Selective Catalytic Reduction

Implementation of SCR controls for 2SLB engines follows the same process and has the same technical drawbacks as discussed in Section 2.1.2.4 of this report.

Typical concerns for SCR system in regards to ammonia slip or insufficient ammonia was not applicable to the engines at Linam. For engines that typically operate at variable loads, such as engines on gas transmission pipelines, a SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia to gain the reductions needed.[16] As Linam Ranch does not typically operate with variable loads, the facility does not expect to have periods of ammonia slip or insufficient ammonia.

The characteristics of 2SLB engine exhaust streams are well understood across industry to be non-favorable conditions for the chemical reactions necessary for SCR to reduce NOx emissions effectively. This is due to undesirable processes occurring in SCR systems as lean burn engines, by design, have higher oxygen level in the exhaust system. In the SCR system of a 2SLB engine, several competitive, nonselective reactions will occur with abundant oxygen. These reactions can either produce secondary emissions or, at best, unproductively consume ammonia as complete oxidation of ammonia generates nitric oxide. For the aforementioned reasons, SCR installation on 2SLB engines requires significant understanding of the process to design, implement and maintain as this type of control system often requires retrofit upgrades/modifications to the engine's combustion system resulting in a custom type control system. Due to the aforementioned reasons, SCR systems have not been widely applied to natural gas fired 2SLB engines similar to those at Linam and application of this control technology can only be seen on very large diesel-fired stationary engines and on large combustion turbines.

Additionally, there is historical precedent that installation of SCR on 2SLB engines can result in significant technical complications, including a necessity to derate the engines and unreliable operation post-retrofit due to a back pressure drop that happens with the exhaust system putting constraints on the engines. Many times, sizing of the SCR system has to be custom designed in accordance with the allowable pressure drop in the exhaust per manufacturer specifications. Another issue using a catalyst (part of the SCR system) on a 2SLB engine is poisoning of the catalyst by lubricant because in two stroke engines, the oil is mixed with either the fuel or the air to lubricate the piston.

AP-42 Section 3.2 does list SCR as an available control technology for 2SLB engines, however, the challenges of applying this control technology on 2SLB engines are strongly asserted by RBLC not identifying SCR as a control for these specific engine models.[17]

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[15] Ibid.
[16] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
[17] Ibid.

Due to the technical barriers associated with SCR as applied to specific 2SLB engines, as described above, it has been determined that this method of NO_X control is technically infeasible for the 2SLB engines at Linam.

2.2.2.4. Non-Selective Catalytic Reduction

Non-Selective Catalytic Reduction (NSCR) is a control technique that uses residual hydrocarbons and carbon monoxide (CO) in engine exhaust as a reducing agent for NO_X. In an NSCR system, hydrocarbons and CO are oxidized by oxygen (O_2) and NO_X. The excess hydrocarbons, CO, and NO_X pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H_2O and CO_2, while reducing NO_X to N_2.[18] This technique does not require additional reagents to be injected because the unburnt hydrocarbons in the engine exhaust are used as the reductant. The chemical reactions for this process are shown in the equations below.[19]

Phase 1:
$$2CO + O_2 \rightarrow 2CO_2$$
$$2H_2 + O_2 \rightarrow 2H_2O$$
$$HC + O_2 \rightarrow CO_2 + H_2O$$

Phase 2:
$$NO_X + CO \rightarrow CO_2 + N_2$$
$$NO_X + H_2 \rightarrow H_2O + N_2$$
$$NO_X + HC \rightarrow CO_2 + H_2O + N_2$$

The reactions in Phase 1 of the chemical process above function to remove excess oxygen from the exhaust stream. This step is necessary because if the oxygen is not removed, it will react more readily with the CO and hydrocarbons than the NO_X, thus reducing the potential for NO_X removal.

Despite this oxygen removal step in the chemical process, the engine exhaust gas stream must already have low levels of excess oxygen, or the oxygen will not be fully removed in Phase 1 and the NO_X removal will not be efficient. Consequently, application of the NSCR control technique is effectively limited to engines with normal exhaust oxygen levels of 4% or less. This does not include lean-burn engines, which typically have an exhaust excess oxygen level around 8%, ranging from 4% to 17%.[20]

The exhaust oxygen levels for 2SLB engines are not sufficiently low to support the reactions described above; therefore, this technology is not a method used to control NO_X emissions from lean-burn engines. Furthermore, NSCR was not identified in the review of the RBLC as a potential control of NO_X emissions from large natural gas-fired lean-burn stationary RICE and AP-42 Section 3.2 does not list NSCR as an available control technique for 2SLB engines.[21] For these reasons, it has been determined that this method of NO_X control is infeasible for the 2SLB engines at Linam.

[18] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines".
[19] U.S. EPA, "Compliance Assurance Monitoring Technical Guidance Document", Appendix B Review Draft, 2005
[20] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
[21] Ibid.

DCP has evaluated the costs of implementing the technologically feasible control technologies as thoroughly as possible in the time provided to complete this assessment. These cost estimates are calculated according to the methods and recommendations in the EPA Air Pollution Control Cost Manual using quotes provided by vendors as well as default assumptions form the Cost Control Manual.[22] Cost effectiveness considerations for the turbines are discussed below, with costs summarized in Table 4.

3.1. NATURAL GAS-FIRED COMBUSTION TURBINES

Table 4. Cost Analysis Summary of Technically Feasible Control Options for Combustion Turbines at Linam

Control Equipment	Unit	Capital Cost ($)	Annual Cost ($)	Emission Reduction (tpy)	Cost Effectiveness ($/ton)[23]
SoLoNOx	29	$188,125	$605,743	29.21	$21,278.01
	30	$188,125	$618,799	25.97	$23,829.64
	31	$1,377,841	$269,048	86.78	$3,100.23
	32B	$1,377,841	$268,605	21.04	$12,764.91
SCR	29	$1,500,000	$256,678	35.81	$7,168.48
	30	$1,500,000	$254,319	33.08	$7,688.74
	31	$1,500,000	$246,027	78.07	$3,151.46
	32B	$1,500,000	$231,770	19.51	$11,880.95

[22] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

[23] Cost Effectiveness and emission reduction as shown in Table 4 are based on 2016 EI information, which reflects a conservative emission calculation approach multiplying turbine operating hours by *permitted PTE emission rate* (lb/hr). Using the actual emission testing data (NSPS KKKK) for these turbines, rather than PTE, the following table reflects what actual emission reduction would be derived from the control technologies and estimated cost effectiveness:

Control Equipment	Unit	Capital Cost ($)	Annual Cost ($)	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
SoLoNOx	29	$188,125	$605,743	0	N/A
	30	$188,125	$618,799	0	N/A
	31	$1,377,841	$269,048	31.98	$8,413.01
	32B	$1,377,841	$268,605	3.82	$70,315.54
SCR	29	$1,500,000	$256,678	13.08	$19,623.74
	30	$1,500,000	$254,319	5.99	$42,457.25
	31	$1,500,000	$246,027	39.71	$6,195.60
	32B	$1,500,000	$231,770	7.45	$31,110.07

DCP has selected to use the EPA Air Pollution Control Cost Spreadsheet for SCR to estimate the costs associated with implementing a SCR control system on the turbines at Linam. The estimate incorporates direct capital cost for equipment and vendor labor, direct annual costs (maintenance, operator costs, reagent cost, electricity cost, and catalyst cost), and indirect costs associated with DCP's internal labor, overhead and capital recovery for the project.

This cost estimate assumes that the SCR will reduce NO_X emissions with a 70% efficiency.[24] There is no historical data to support a higher control efficiency assumption. In addition, due to the age of the units and current availability of control equipment for them, it is assumed that there would be significant difficulties retrofitting each of these turbines due to initial assessment and the need of a custom engineered SCR system.

These cost estimates have been developed, and applied to the retrofit of these turbines based on two approaches: (i) in Table 4 using the 2016 Emission Inventory submittal for Linam, which is based on PTE for the turbines, so it reflects a potential or theoretical emissions reduction if the turbine were operating at its maximum permitted emissions rate, and; (ii) the Table in Footnote 23 using NSPS KKKK testing data for these turbines reflecting actual emissions for the turbines, thus reflecting actual emissions reductions that would be achieved. A copy of the EPA Air Pollution Control Cost Spreadsheet for each unit is included in Appendix B of this report. Based on actual emissions reductions, these technologies reflect a cost-effectiveness of over $5,000 per ton on the lowest-side, and generally tens of thousands of dollars per ton for these turbines.

[24] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

The second factor in this analysis is the time necessary for compliance. Consideration of this factor involves estimating the time required for a source to implement a potential control measure. This information is provided here in order to advise the NMED of DCP's projection of a reasonable compliance timeline based on the equipment and site-specific considerations that could affect the time necessary to comply.

4.1. NATURAL GAS-FIRED COMBUSTION TURBINES

DCP estimates that approximately 13 months will be needed to budget, design, procure, and construct the SoLoNO$_X$ control equipment. Factors that have been considered for this anticipated timeline include time for DCP to budget and allocate funds (3 months); 6 months for unit inspection and delivery; and 3 weeks for installation. A contingency factor of 25% has also been applied to account for potential circumstances or setbacks associated with installation of this new technology.

DCP is not certain whether standard SCR technology can be found to be applied to these particular turbines at Linam given their age, design and the fact that such control system is not provided by the turbine manufacturer. It is possible that SCR technology for the turbines at Linam may need to be custom engineered and developed. DCP estimates that approximately 9 months would be needed to budget, design, procure, and construct the SCR control equipment. Factors that have been considered for this anticipated timeline include time for DCP to budget and allocate funds (3 months); and 4 months to design, deliver and install SCR technology. A contingency factor of 25% has also been applied to account for potential circumstances or setbacks associated with installation of this new technology.

This section addresses the potential energy and non-air environmental impacts that installation of the technically feasible control options pose on a source. The consideration of energy impacts involves assessing the impact of a control measure on the energy that is consumed by the source. Non-air environmental impacts are assessed based on the effect of the control on non-air environmental media. Some examples of non-air environmental impacts include water resource depletion, solid waste generation, increased noise and odor pollution, and increased land usage.

5.1. NATURAL GAS-FIRED COMBUSTION TURBINES

The implementation of SCR on the turbines at Linam would result in several energy and non-air impacts. The primary impact of this control would be a significant increase in energy consumption, which would be necessary to power the units. The estimated energy consumption for each unit is summarized in Table 5, and is based on the EPA Air Pollution Control Cost Manual.[25] The calculation for these values is included in Appendix B of this report.

Table 5. Energy Consumption Analysis Summary

Unit	Annual Energy Consumption
29	349.7 MWh/year
30	333.1 MWh/year
31	165.8 MWh/year
32B	163.1 MWh/year
Total	1011.6 MWh/year

In addition to the increased energy burden, there are several non-air environmental impacts associated with the handling and storage of the reagent used in the SCR system, typically ammonia or urea. Ammonia is a Toxic Air Pollutant (TAP) regulated under 20.2.72.502 NMAC with an occupational exposure limit (OEL) of 18 mg/m^3. In both soil and water, urea is hydrolyzed quickly to ammonia and carbon dioxide by urease, an extracellular enzyme that originates from microorganisms and plant roots.[26] Short-term inhalation exposure to high levels of ammonia in humans can cause irritation and serious burns in the mouth, lungs, and eyes. Chronic exposure to airborne ammonia can increase the risk of respiratory irritation, cough, wheezing, tightness in the chest, and impaired lung function in humans. Animal studies also suggest that exposure to high levels of ammonia in air may adversely affect other organs, such as the liver, kidney, and spleen.[27]

[25] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual
[26] U.S. EPA, EPA/635/R-10/005F, "Toxilogical Report of Urea", July 2011
[27] U.S. EPA, EPA/635/R-16/163Fc, "Toxicological Review of Ammonia Noncancer Inhalation: Executive Summary", September 2016

Unavoidable releases of ammonia could have significant and irreversible impacts on the living and physical environment affected. Storage and handling of urea or ammonia onsite would result in an increased risk to the health and safety of facility operators. Linam is a Gas Plant, which already maintains a high level of health and safety risk. DCP considers any increase to this risk unacceptable.

The anticipated remaining useful life of each source is addressed here for the NMED's consideration. The assessment of this factor involves estimating how long the sources analyzed will remain in operation and the lifetime of potential control measures, accounting for equipment and site-specific limitations.

40 CFR Part 51, Appendix Y includes guidance on the characterization of this factor, stating that the remaining useful life of a source will typically be longer than the useful life of the emission control system. Therefore, it is appropriate to annualize compliance costs based on the useful life of the control equipment, rather than the life of the source.[28]

6.1. NATURAL GAS-FIRED COMBUSTION TURBINES

Based on their current age and operating efficiency, it is estimated that the remaining useful life of the turbines will be longer than the SCR units. The turbines have operated for more than 40 years without any significant deterioration in operating efficiency; therefore, this analysis of the remaining useful life of the equipment will be based on the anticipated useful life of the SoLoNO$_X$ and SCR control technologies.

The estimated useful life of the SoLoNO$_X$ control technology is 20 years, based on default values from the EPA Air Pollution Control Cost Manual.[29]

The estimated useful life of the SCR control technology is 20 years, based on default values from the EPA Air Pollution Control Cost Manual.[30]

[28] 40 CFR 51, Appendix Y, Section II.B.4.f
[29] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual
[30] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

7. SUMMARY & CONCLUSIONS

Based on a comprehensive review of the RBLC, available literature, and manufacturer's input of potentially available control technologies for the natural-gas fired turbines located at Linam, DCP has determined that both SoLoNO$_X$ and SCR are technically feasible control options for the turbines. DCP notes that there are significant cost implications for each turbine at the facility with these technologies, that there are significant time and resource expenditures necessary for these technologies, and that there are significant energy and non-air impacts associated with these technologies particularly the SCR technology. DCP further notes that, considering the information reflected in this report, these control technologies are not cost-effective for the estimated reasonable progress improvement, and further notes that DCP's Linam Ranch natural gas processing plant is barely over the agency's Q/d assessment threshold of 5.5 with a Q/d of 7.6.

Appendix A – RBLC Tables
Appendix B – Cost Calculations and EPA Cost Analysis Spreadsheets

APPENDIX A - RBLC TABLES

RBLC Analysis for Natural Gas Fired Turbines – NO_X Control

	Control Technology	Good Combustion Technique	Improved Combustion Technology (Low-NO_X Combustors, Ultra-Low NO_X Combustors and other improved combustion technology)[a]	Water/Steam Injection[b]	Selective Catalytic Reduction (SCR)[c]
IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	NO_x emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. Primary combustion occurs at lower temperatures under oxygen-deficient conditions. By following EPA's "Good Combustion Practices" guidance document, good combustion practices can be maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices the unit will operate as intended with the optimal NO_x emissions.	Low-NO_x burners employ multi-staged combustion to inhibit the formation of NO_X. Primary combustion occurs at lower temperatures under oxygen-deficient conditions; secondary combustion occurs in the presence of excess air. This category includes Improved Combustion Technology Lean Head End Liners for the GE turbines assessed here.	Injected water/steam acts as a heat sink, lowering combustion zone peak temperatures, resulting in a decrease in thermal NO_X.	A nitrogen-based reagent (e.g., ammonia, urea) is injected into the exhaust stream downstream of the combustion unit. The reagent reacts selectively with NO_X to produce molecular N_2 and water in a reactor vessel containing a metallic or ceramic catalyst.
	Other Considerations	N/A	N/A	Results in a small efficiency penalty but an increase in power output. May increase CO and VOC emissions. Not available in certain models.	Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as "ammonia slip." Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.
	RBLC Database Information	Included in RBLC for control of NO_X emissions from combustion turbines.	Included in RBLC for the control of NO_X emissions from combustion turbines.	Not included in RBLC for the control of NO_X emissions from combustion turbines; identified as a control option based on AP-42 Section 3.1.	Included in RBLC for the control of NO_X emissions from combustion turbines.
ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	Feasibility Discussion	Technically feasible.	Technically infeasible. This option is not available for the turbine model.	Technically infeasible. This option is not available for the turbine model.	Technically feasible.
RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	Base Case			63%

a. California EPA, Air Resources Board, "Section 311 - Non-Selective Catalytic Reduction and Other NO_X Controls," http://www.arb.ca.gov/cap/manuals/cntrldev/sncr_etc/311nscr.htm
b. U.S. EPA, AP-42 Section 3.1, "Stationary Gas Turbines"
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

Turbine RBLC Results

Completed RBLC Search on 9/19/2019 for a ten year period of 1/1/2019 to 09/19/2019

RBLCID	FACILITY NAME	EPA REGION	PERMIT NUM	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	COST EFFECTIVENESS	INCREMENTAL COST EFFECTIVENESS	Cost Verified	DOLLAR YEAR USED IN COST ESTIMATES
AK-0083	XENAI NITROGEN OPERATIONS	10	AQ0083CPT06	Five (5) Natural Gas Fired Combustion Turbines	16.11	Natural Gas	37.6	MMBTU/H	Five (5) Natural Gas-Fired Solar Combustion Turbines rated at 37.6 MMBtu/hr each. Installed in 1976.	Nitrogen Oxides (NOx)	A	Selective Catalytic Reduction	0			0	0	N	
CA-1215	QUALCOMM INC.	9	2012- APP-002100	Cogeneration gas turbine	16.11	natural gas	4.37	MW	Manufacturer: Solar Turbines- Model: Mercury 50-6400R	Nitrogen Oxides (NOx)	A	SoLoNOx burner (Ultra lean Premix)	0			0	0	N	
LA-0331	CALCASIEU PASS LNG PROJECT	6	PSD-LA-805	Aeroderivative Simple Cycle Combustion Turbine	16.11	Natural Gas	263	MM BTU/h		Nitrogen Oxides (NOx)	B	Selective Catalytic Reduction (SCR), exclusive combustion of fuel gas, and good combustion practices.	0			0	0	N	
MI-0410	THETFORD GENERATING STATION	5	191-12	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	16.11	natural gas	171	MMBTU/H	Two natural gas fired simple cycle combustion turbines each with an electrical generator (nominal 13MW each; 171 MMBtu/hr heat input rating each). Each turbine is limited to 343 MMscf of natural gas per 12-month rolling time period as determined at the end of each calendar month. Both turbines combined are limited to 5.15 MMscf of natural gas each calendar day.	Nitrogen Oxides (NOx)	P	Dry low-NOx combustors	0			0	0	N	
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	5	185-15	FG-TURBINES	16.11	Natural gas	10504	HP	Five (5) simple cycle natural gas-fired combustion turbines (CTs) to drive compressors that will be used to transport natural gas through pipelines. The turbines are identified as EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, and EUTURBINE5 within the flexible group FGTURBINES. There shall be no more than a combined total of 5 events (startup or shutdown) per clock hour. The total number of startup events for all units combined shall not exceed 500 events per 12-month rolling time period. The total number of shutdown events for all units combined shall not exceed 500 events per 12-month rolling time period. The maximum nominal rating of each turbine shall not exceed 10,504 HP (ISO).	Nitrogen Oxides (NOx)	A	Dry ultra-low NOx burners	0			0	0	N	
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	5	185-15A	FGTURNBINES (5 Simple Cycle CTs: EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5)	16.11	Natural gas	10504	HP	Five simple cycle natural gas-fired combustion turbines (CTs) to drive compressors that will be used to transport natural gas through pipelines (EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5 in FGTURBINES). There shall be no more than a combined total of 5 events (startup or shutdown) per clock hour. The total number of startup events for all units combined shall not exceed 500 events per 12-month rolling time period. The total number of shutdown events for all units combined shall not exceed 500 events per 12-month rolling time period. The maximum nominal rating of each turbine shall not exceed 10,504 HP (ISO).	Nitrogen Oxides (NOx)	A	Dry ultra-low NOx burners.	0			0	0	N	
NV-0050	MGM MIRAGE	9	825	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	16.11	NATURAL GAS	4.6	MMBTU/H	THE TWO UNITS ARE IDENTICAL SOLAR MERCURY COMBUSTION GAS TURBINES FOR ELECTRIC POWER GENERATION. EACH UNIT IS RATED AT 4.6 MMBTU/HR, AND IS ALLOWED TO OPERATE 24 HOURS/DAY AND 8,760 HOURS/YEAR.	Nitrogen Oxides (NOx)	P	LEAN PRE-MIX TECHNOLOGY AND LIMITING THE FUEL TO NATURAL GAS ONLY	0.178	LB/MMBTU		0	0	N	
OK-0148	BUFFALO CREEK PROCESSING PLANT	6	2012-1026-C-PSD	Small Combustion Turbines (<25MW)	16.11	Natural Gas	10179	Horsepower	Solar Taurus 70-10802S times 2	Nitrogen Oxides (NOx)	P	Dry-Low NOx Combustion	0			0	0	N	
OK-0153	ROSE VALLEY PLANT	6	2012-1393-C-PSD	TURBINES 9,443 HP SIEMENS SGT-200-2S	16.11	NATURAL GAS	9443	HP	THERE ARE TO BE LIKE-KIND TURBINES.	Nitrogen Oxides (NOx)	P	DRY LOW-NOx COMBUSTION.	0			0	0	N	
*PA-0314	BEECH HOLLOW	3	63-029220	COMBUSTION TURBINE without DUCT BURNERS UNIT	16.11	Natural Gas	2413	$MMBtu/hr$	CEMS for NOx, CO	Nitrogen Oxides (NOx)	A	SCR	0			0	0	N	
TX-0642	SINTON COMPRESSOR STATION	6	PSDTX1304	Compression Turbine	16.11	natural gas	20000	hp	Two (2) 20,000 horsepower Solar Titan 130S turbines in natural gas pipeline compression service	Nitrogen Oxides (NOx)	P	Solar's SoLoNOx dry emission control technology	0			0	0	N	
TX-0685	GUADALUPE GENERATING STATION	6	106011 PSDTX1110	(2) simple cycle turbines	16.11	natural gas	190	MW	Four models are approved: GE7FA.03, GE7FA.04, GE7FA.05, or Siemens SW 5000FS. 383 MW to 454 MW total plant capacity.	Nitrogen Oxides (NOx)	B	DLN burners, limited operation	0			0	0	N	
*WI-0283	AFE, INC. â€"LCM PLANT	5	17-J0W-207	P90 â€" Natural Gas-Fired Emergency Generator	16.11	Natural Gas	9.51	mmBTU/hr	750 kW or 1,114 brake horsepower	Nitrogen Oxides (NOx)	P	Good Combustion Practices and the Use of Turbocharger and Aftercooler	0			0	0	N	
WY-0067	ECHO SPRINGS GAS PLANT	8	MD-7837	TURBINES S35-S36	16.11	NATURAL GAS	12555	HP	TWO (2) 12,555 HP SOLAR MARS 100-15000S TURBINES	Nitrogen Oxides (NOx)	N	SOLONOX	0			0	0	N	
WY-0067	ECHO SPRINGS GAS PLANT	8	MD-7837	TURBINE S34	16.11	NATURAL GAS	9856	HP	SOLAR CENTAUR 40-T4700S	Nitrogen Oxides (NOx)	N	SOLONOX	0			0	0	N	

RBLC Analysis for Natural Gas-Fired Lean-Burn RICE – NO_X Control

	Control Technology	Good Combustion Practices and Fuel Selection	Clean Burn Technology [a]	Selective Catalytic Reduction (SCR) [b,c]	Non-Selective Catalytic Reduction (NSCR) [c]
IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	NO_x emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following EPA's "Good Combustion Practices" guidance document, good combustion practices can be maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices the unit will operate as intended with the optimal NO_x emissions.	Natural gas fueled engines that operate with a fuel-lean air/fuel ratio are capable of low NO_X emissions.	A nitrogen-based reagent (e.g., ammonia, urea) is injected into the exhaust stream downstream of the combustion unit. The reagent reacts selectively with NO_x to produce molecular N_2 and water in a reactor vessel containing a metallic or ceramic catalyst.	This technique uses residual hydrocarbons and CO in rich-burn engine exhaust as a reducing agent for NO_x. In an NSCR, hydrocarbons and CO are oxidized by O_2 and NO_x. The excess hydrocarbons, CO, and NO_x pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H_2O and CO_2, while reducing NO_x to N_2.[b]
	Other Considerations	N/A	N/A	Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as "ammonia slip." Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.	N/A
ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Not included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Not included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.
	Feasibility Discussion	Technically feasible.	Technically feasible.	Technically infeasible. Site and unit-specific complications exclude SCR as a control option for the 2SLB engines at this facility.	Technically infeasible. The NSCR technique is limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes 4-stroke rich-burn naturally aspirated engines and some 4-stroke rich-burn turbocharged engines. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures.
RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	Base Case	80 - 93%		

a. U.S. EPA, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document – NOX Emissions from Stationary Reciprocating Internal Combustion Engines", EPA-453/R-93-032, Section 5.2.5.4, July 1993
b. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
c. U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"

Engine RBLC Results

Completed RBLC Search on 9/19/2019 for a ten year period of 1/1/2019 to 09/19/2019

RBLCID	FACILITY NAME	EPA REGION	PERMIT NUM	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	COST EFFECTIVENESS	INCREMENTAL COST EFFECTIVENESS	Cost Verified	DOLLAR YEAR USED IN COST ESTIMATES
CA-1192	AVENAL ENERGY PROJECT	9	SJ 08-03	EMERGENCY IC ENGINE	17.13	NATURAL GAS	550	KW	UNIT IS 860 HP	Nitrogen Oxides (NOx)	A	SCR, OPERATIONAL LIMIT OF 50 HRS/YR	0			0	0	N	
CA-1222	KYOCERA AMERICA INC.	9	2011-APP-001634	ICE: Spark Ignition	17.13	natural gas	2889	bhp	anther one is 2328 bhp	Nitrogen Oxides (NOx)	A	SCR with process control NOx monitor	0			0	0	N	
CA-1240	GOLD COAST PACKING	9	14646	Internal Combustion Engine	17.13	Natural gas	881	bhp		Nitrogen Oxides (NOx)	A	SCR catalyst-Urea injection	0			0	0	N	
*FL-0368	NUCOR STEEL FLORIDA FACILITY	4	1050472-001-AC	Emergency Engines	17.13	Natural gas	0		Two 2,000-kW Emergency Natural Gas-Fired Generators & One Emergency Natural Gas-Fired 500 HP Fire Pump	Nitrogen Oxides (NOx)	P	Good combustion practices	0			0	0	N	
IN-0167	MAGNETATION LLC	5	181-32081-00054	EMERGENCY GENERATOR	17.13	NATURAL GAS	620	HP	EMERGENCY NATURAL GAS GENERATOR, IDENTIFIED AS EU017, EXHAUSTS TO STACK SV016.	Nitrogen Oxides (NOx)	P	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0			0	0	N	
*KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	7	C-13309	Spark ignition RICE emergency AC generators	17.13	Natural gas	450	KW	Two (2) spark ignition emergency AC generators, each rated at 450 kW (approximately 604 BHP), which shall burn only natural gas for fuel for the purpose of providing emergency power.	Nitrogen Oxides (NOx)	N		0			0	0	N	
*KS-0030	STATION	7	C-13309	(EGUs)	17.13	Natural Gas	10	MW	G20CM34), used to generate electricity. The generating capacity of	Nitrogen Oxides (NOx)	N		0			0	0	N	
KS-0035	LACEY RANDALL GENERATION FACILITY, LLC	7	C-10593	spark ignition four stroke lean burn reciprocating internal combustion engine (RICE) electric generating units (EGUs)	17.13	Natural gas	12526	BHP	Ten new spark ignition RICE EGUs (Wartsila model 20V34SG), used to generate electricity. The generating capacity of each EGU will be 9.34 megawatts (approximately 12,526 BHP). Each EGU shall be equipped with a selective catalytic reduction (SCR) system and an oxidation catalyst, and shall burn only pipeline quality natural gas for fuel.	Nitrogen Oxides (NOx)	A	Selective Catalytic Reduction (SCR) system and oxidation catalyst	0			0	0	N	
LA-0257	SABINE PASS LNG TERMINAL	6	PSD-LA-703(M3)	Generator Engines (2)	17.13	Natural Gas	2012	hp		Nitrogen Oxides (NOx)	P	Comply with 40 CFR 60 Subpart JJJJ	2	G/BHP-HP-H		0	0	N	
LA-0287	ALEXANDRIA COMPRESSOR STATION	6	PSD-LA-787	Emergency Generator Reciprocating Engine (G30, EQT 15)	17.13	Natural Gas	1175	HP	Non-emergency operation limited to 100 hours per year. Engine is subject to NSPS Subpart JJJJ.	Nitrogen Oxides (NOx)	P	Good combustion practices; use of natural gas as fuel; limit non-emergency use to <= 100 hours per year; adherence to the permittee's operating and maintenance practices	2	G/BHP-HR		0	0	N	
LA-0292	HOLBROOK COMPRESSOR STATION	6	PSD-LA-769(M-1)	Waukesha 16V-275GL Compressor Engines Nos. 1-12	17.13	Natural Gas	5000	HP		Nitrogen Oxides (NOx)	P	Lean-burn combustion, use of natural gas as fuel, good equipment design, and proper combustion techniques	0.45	G/BHP-HR		0	0	N	
MI-0393	RAY COMPRESSOR STATION	5	206-09	Five spark ignition internal combustion engines	17.13	natural gas	32	MMBTU/H	Five (5) natural gas fired spark ignition ICEs; Caterpillar G3616, 4735 hp lean burn engines with 2 way oxidation catalysts.	Nitrogen Oxides (NOx)	N	low emission design and good combustion practices	0			0	0	N	
MI-0393	RAY COMPRESSOR STATION	5	206-09	Emergency generator	17.13	natural gas	500	H/YR	This is an emergency generator which is limited to 500 hours per year of operation.	Nitrogen Oxides (NOx)	N		0			0	0	N	
MI-0401	MIDLAND POWER STATION	5	24-11B	Emergency generator	17.13	Natural gas	1200	KW output	This is a 1200kW (output) natural gas fired emergency generator. The engine was manufactured after 2009	Nitrogen Oxides (NOx)	N		0			0	0	N	
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	5	107-13	Emergency Engine--natural gas (EUNGENGINE)	17.13	natural gas	1000	kW	A 1,000 kilowatts (kW) natural gas-fueled emergency engine manufactured in 2013. The engine is used to charge the batteries in the uninterruptible power supply (UPS) battery system (EUNGENGINE). Restricted to 500 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	P	Good combustion practices	0			0	0	N	
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	5	185-15	EUN_EM_GEN	17.13	Natural gas	225	H/YR	A 1,506 kilowatts (kW) natural gas fueled emergency engine manufactured in 2011 or later. The engine is used to provide electrical power to the station and support equipment in the event power from the public utility grid system is lost (EUN_EM_GEN). Restricted to 225 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	B	Low NOx design (turbo charger and after cooler) and good combustion practices.	0			0	0	N	
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	5	107-13C	EUNGENGINE (Emergency engine--natural gas)	17.13	Natural gas	500	H/YR	A 1,462 HP natural gas-fueled emergency engine manufactured in 2016 serving a 1,040 kW generator. The engine is used to charge the batteries in the uninterruptible power supply (UPS) battery system (EUNGENGINE). Restricted to 144 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	P	Good combustion practices.	0			0	0	N	
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	5	185-15A	EUN_EM_GEN (Natural gas emergency engine).	17.13	Natural gas	205	H/YR	A nominally rated 1,300 electrical kilowatts (ekW) output emergency genset containing a 1,818 HP natural gas fueled engine manufactured in 2011 or later. The engine is used to provide electrical power to the station and support equipment in the event power from the public utility grid system is lost (EUN_EM_GEN). Restricted to 205 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	B	Low NOx design (turbo charger and after cooler) and good combustion practices.	0			0	0	N	
OK-0148	BUFFALO CREEK PROCESSING PLANT	6	2012-1026-C PSD	Large Internal Combustion Engines (>500 hp)	17.13	Natural Gas	1775	Horsepower	Caterpillar G3606LE 4SLB times 6.	Nitrogen Oxides (NOx)	P	Ultra Lean Burn	0			0	0	N	
OK-0148	BUFFALO CREEK PROCESSING PLANT	6	2012-1026-C PSD	Large Internal Combustion Engines (>500 hp)	17.13	Natural Gas	2370	Horsepower	Caterpillar G360BLE 4SLB times 4.	Nitrogen Oxides (NOx)	P	Ultra Lean Burn	0			0	0	N	
OK-0153	ROSE VALLEY PLANT	6	2012-1393-C PSD	COMPRESSOR ENGINE 1,775-HP CAT G3606LE	17.13	NATURAL GAS	1775	HP	THERE ARE TO BE TEN (10) LIKE-KIND ENGINES.	Nitrogen Oxides (NOx)	N		0			0	0	N	
OK-0153	ROSE VALLEY PLANT	6	2012-1393-C PSD	EMERGENCY GENERATORS 2,889-HP CAT G3520C IM	17.13	NATURAL GAS	2889	HP	THERE ARE TO BE TWO (2) ENGINES, EACH EQUIPPED W/AN OXIDATION CATALYST. THESE WILL BE LIMITED USE (< 750 HOURS PER YEAR).	Nitrogen Oxides (NOx)	P	LEAN-BURN COMBUSTION.	0			0	0	N	
PA-0287	WELLING COMPRESSOR STATION	3	63-00958	CATERPILLAR G3516B COMPRESSOR ENGINES (2)	17.13	Natural Gas	0			Nitrogen Oxides (NOx)	N		6.64	T/YR	EACH ENGINE	0	0	N	
PA-0287	WELLING COMPRESSOR STATION	3	63-00958	WAUKESHA P9390GSI COMPRESSOR ENGINES (4) (1980 BHP)	17.13	Natural Gas	0			Nitrogen Oxides (NOx)	A	3-way catalyst, Johnson Matthey	3.82	T/YR	EACH ENGINE	0	0	N	
PA-0297	KELLY IMG ENERGY LLC/KELLY IMG PLT	3	16-161A	3.11 MW GENERATORS (WAUKESHA) #1 and #2	17.13	Natural Gas	0			Nitrogen Oxides (NOx)	N		0			0	0	N	
PA-0301	CARPENTER COMPRESSOR STATION	3	GP5-63-00987	Three Four Stroke Lean Burn Engine - Caterpillar G3608 TA, 2370 BHP	17.13	Natural Gas	0		Controlled by oxidation Catalyst, regulated by automatic air/fuel ratio controllers.	Nitrogen Oxides (NOx)	N		0			0	0	N	
PA-0301	CARPENTER COMPRESSOR STATION	3	GP5-63-00987	One four stroke lean burn engine, Caterpillar Model G3612 TA, 3550 bhp	17.13	Natural Gas	0		Controlled by Oxidation catalyst, regulated by an integrated automatic air/fuel ration controller.	Nitrogen Oxides (NOx)	N		0			0	0	N	
PA-0302	CLERMONT COMPRESSOR STATION	3	GP5-24-180A	Spark Ignited 4 stroke Rich Burn Engine (7 units)	17.13	Natural Gas	0		Spark Ignited 4 stroke Rich Burn Engine (7 units)	Nitrogen Oxides (NOx)	A	NSCR	0			0	0	N	
TX-0642	SINTON COMPRESSOR STATION	6	PSDTX1304	Emergency Engine	17.13	natural gas	1328	hp	1328 horsepower standby generator operating no more than 100 hours per year	Nitrogen Oxides (NOx)	N		0			0	0	N	
TX-0680	SONORA GAS PLANT	6	106139 PSDTX1316	Refrigeration compressor engine	17.13	natural gas	1183	hp	(4) Caterpillar 3516 ultra-lean burn compressor engines at 1,183 hp each	Nitrogen Oxides (NOx)	P	ultra-lean burn technology	0			0	0	N	
TX-0680	SONORA GAS PLANT	6	106139 PSDTX1316	Recompression compressor engine	17.13	natural gas	1380	hp	(8) ultra-lean burn Caterpillar 3516 engines at 1,380 hp each	Nitrogen Oxides (NOx)	P	ultra-lean burn technology	0			0	0	N	
TX-0692	RED GATE POWER PLANT	6	106544 PSDTX1322	(12) reciprocating internal combustion engines	17.13	natural gas	18	MW	12 â€" 18 MW Wartsila 18V50SG natural gas-fired engines, each with an associated electric generator	Nitrogen Oxides (NOx)	A	Selective Catalytic Reduction (SCR)	0			0	0	N	
TX-0755	RAMSEY GAS PLANT	6	117323 AND PSDTX1392_O-3546	Internal Combustion Compressor Engines	17.13	Residue gas equivalent to natural gas	206149	MMBtu/yr	Each cryogenic plant at the Ramsey Gas Plant will have 5 natural gas-fired compressor engines. The residue gas from each plant will be compressed by five compressors.	Nitrogen Oxides (NOx)	P	Ultra Lean-burn engines firing natural gas	0			0	0	N	
WY-0066	MEDICINE BOW IGL PLANT	8	CT-5873	BLACK START GENERATOR 1	17.13	NATURAL GAS	2889	HP	250 HOURS OF OPERATION	Nitrogen Oxides (NOx)	N	LIMITED OPERATING HOURS (250 HR/YR)	0.8	T/YR	ANNUAL	0	0	N	
WY-0066	MEDICINE BOW IGL PLANT	8	CT-5873	BLACK START GENERATOR 2	17.13	NATURAL GAS	2889	HP	LIMITED OPERATING HOURS (250 HR/YR)	Nitrogen Oxides (NOx)	N	LIMITED OPERATING HOURS (250 HR/YR)	0.8	T/YR	ANNUAL	0	0	N	
WY-0066	MEDICINE BOW IGL PLANT	8	CT-5873	BLACK START GENERATOR 3	17.13	NATURAL GAS	2889	HP	LIMITED OPERATING HOURS (250 HR/YR)	Nitrogen Oxides (NOx)	N	LIMITED OPERATING HOURS (250 HR/YR)	0.8	T/YR	ANNUAL	0	0	N	

APPENDIX B – COST ANALYSIS CALCULATIONS

DCP Operating Company, LP
Linam Ranch Gas Plant

Turbine Cost Analysis Interest Rate: 5.50%
All Units Period (yrs): 20

Control Equipment	Unit	Capital Cost ($)	Total Annual Cost* ($)	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Improved Combustion ($SoLoNO_X$)	29	$188,125	$605,743	29.21	$21,278.01
	30	$188,125	$618,799	25.97	$23,829.64
	31	$1,377,841	$269,048	86.78	$3,100.23
	32B	$1,377,841	$268,605	21.04	$12,764.91
Selective Catalytic Reduction (SCR)	29	$1,500,000	$256,678	35.81	$7,168.48
	30	$1,500,000	$254,319	33.08	$7,688.74
	31	$1,500,000	$246,027	78.07	$3,151.46
	32B	$1,500,000	$231,770	19.51	$11,880.95

* Total Annual Cost includes the annualized capital cost as well as the direct and indirect annual operating costs.

Control Equipment	Unit	Capital Cost ($)	Total Annual Cost* ($)	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Improved Combustion ($SoLoNO_X$)	29	$188,125	$605,743	0	N/A
	30	$188,125	$618,799	0	N/A
	31	$1,377,841	$269,048	31.98	$8,413.01
	32B	$1,377,841	$268,605	3.82	$70,315.54
Selective Catalytic Reduction (SCR)	29	$1,500,000	$256,678	13.08	$19,623.74
	30	$1,500,000	$254,319	5.99	$42,457.25
	31	$1,500,000	$246,027	39.71	$6,195.60
	32B	$1,500,000	$231,770	7.45	$31,110.07

* Total Annual Cost includes the annualized capital cost as well as the direct and indirect annual operating costs.

Control Equipment	Unit	Energy Consumption MWh/yr
Selective Catalytic Reduction (SCR)	29	349.7
	30	333.1
	31	165.8
	32B	163.1
	Total	**1011.6**

DCP Operating Company, LP
Linam Ranch Gas Plant

Solar Taurus 70-10302S	Interest Rate:	5.50%
Unit 29	Period (yrs):	20

Base (35 ppm)

NO_X ppm:		35	ppm	
NO_X lb/hr:		11.82	lb/hr	<-- From 2016 EI calculations
NO_X tpy:		51.15	tpy	<-- From 2016 EI calculations

SoLoNO$_X$ (15 ppm)

NO_X guarantee:		15	ppm	<-- from Solar
NO_X lb/hr:		5.07	lb/hr	
NO_X tpy:		21.94	tpy	
Total Cap Investment	$	188,125		<-- from Solar
Annualized TCI:	$	15,742		<-- Based on interest rate, year and TCI
Annual O&M Costs[1]:	$	605,743		<-- Includes O&M and overhaul costs
Total Annual Costs:	$	621,486		
Emissions Reduction:		29.21	tpy	
Cost Effectiveness:	**$**	**21,278.01**	**$/ton**	

[1] From Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Timeline for Compliance (Docket ID No. EPA-HQ-OAR-2015-0500) Section 3.3.3, Corrected from 1999 to 2018 dollars based on CEPCI. Also includes cost of overhaul as provided by SoLoNO$_x$.

SCR (10 ppm)

NO_X guarantee:		10	ppm	<-- Assumed 70% from AP-42 Section 3.1.4.3
NO_X lb/hr:		3.55	lb/hr	
NO_X tpy:		15.35	tpy	
Total Cap Investment	$	1,500,000		<-- Vendor estimate
Annualized TCI:	$	125,519		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	131,159		<-- from Cost Control Spreadsheet
Total Annual Costs:	$	256,678		
Emissions Reduction:		35.81	tpy	
Cost Effectiveness:	**$**	**7,168.48**	**$/ton**	
Incremental Cost:	$	(14,109.53)	$/ton	

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine? Industrial

Is the SCR for a new turbine or retrofit of an existing turbine? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	77.63	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,020	Btu/scf
What is the estimated actual annual fuel consumption?	658,580,746	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 3710 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = _____ percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired turbines, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the turbine operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.152	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.046	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	603.1	2018 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh			* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	78	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	666,724,528	scf/Year	
Actual Annual fuel consumption (Mactual) =		658,580,746	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.988	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8653	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	8.28	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	35.81	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.88		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	35,954	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	137.74	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.14		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia	
Retrofit Factor (RF)	Retrofit to existing turbine	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	261.03	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	37	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	43	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	6.6	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	50	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	3	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	11	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	1	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	500	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ =	39.92	kW
	where A = (0.1 x QB) for industrial turbines.	349683.0549	kWh/yr
		349.6830549	MWh/yr

Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	$1,500,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =		$128,441 in 2018 dollars
Indirect Annual Costs (IDAC) =		$128,268 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC		$256,709 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Operating Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$7,500 in 2018 dollars
Annual Operating Cost =	Operator Labor Rate x Hours/Day x t_{SCR} =	$87,600 in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$3,756 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$23,350 in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$6,235 in 2018 dollars
Direct Annual Cost =		$128,441 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,718 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$125,550 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$128,268 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$256,709 per year in 2018 dollars
NOx Removed =	36 tons/year
Cost Effectiveness =	$7,169 per ton of NOx removed in 2018 dollars

DCP Operating Company, LP
Linam Ranch Gas Plant

Solar Taurus 70-9702S	Interest Rate:	5.50%
Unit 30	Period (yrs):	20

Base (33 ppm)

NO_X ppm:		33	ppm	
NO_X lb/hr:		11.26	lb/hr	<-- From 2016 EI calculations
NO_X tpy:		47.25	tpy	<-- From 2016 EI calculations

SoLoNO$_X$ (15 ppm)

NO_X guarantee:		15	ppm	<-- from Solar
NO_X lb/hr:		5.07	lb/hr	
NO_X tpy:		21.28	tpy	
Total Cap Investment	$	188,125		<-- from Solar
Annualized TCI:	$	15,742		<-- Based on interest rate, year and TCI
Annual O&M Costs[1]:	$	603,057		<-- Includes O&M and overhaul costs
Total Annual Costs:	$	618,799		
Emissions Reduction:		25.97	tpy	
Cost Effectiveness:	**$**	**23,829.64**	**$/ton**	

[1] From Assessment of Non-EGU NO_x Emission Controls, Cost of Controls, and Timeline for Compliance (Docket ID No. EPA-HQ-OAR-2015-0500) Section 3.3.3, Corrected from 1999 to 2018 dollars based on CEPCI. Also includes cost of overhaul as provided by SoLoNO$_x$.

SCR (10 ppm)

NO_X guarantee:		10	ppm	<-- Assumed 70% from AP-42 Section 3.1.4.3
NO_X lb/hr:		3.38	lb/hr	
NO_X tpy:		14.18	tpy	
Total Cap Investment	$	1,500,000		<-- Vendor estimate
Annualized TCI:	$	125,519		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	128,800		<-- from Cost Control Spreadsheet
Total Annual Costs:	$	254,319		
Emissions Reduction:		33.08	tpy	
Cost Effectiveness:	**$**	**7,688.74**	**$/ton**	
Incremental Cost:	$	(16,140.90)	$/ton	

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine? Industrial

Is the SCR for a new turbine or retrofit of an existing turbine? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	73.95	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,020	Btu/scf
What is the estimated actual annual fuel consumption?	608,459,422	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3710	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = _____ percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired turbines, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the turbine operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.15	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.046	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	603.1	2018 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh			* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	74	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	635,065,475	scf/Year
Actual Annual fuel consumption (Mactual) =		608,459,422	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.958	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8393	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	7.88	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	33.08	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.88	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	34,247	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	137.74	/hour
Residence Time	1/V_{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.14	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia
Retrofit Factor (RF)	Retrofit to existing turbine	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	248.63	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	36	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	41	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	6.4	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	50	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	3	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	11	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	1	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	500	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ =	38.02	kW
	where A = (0.1 x QB) for industrial turbines.	333078.5449	kWh/yr
		333.0785449	MWh/yr

Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	$1,500,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =		$126,082 in 2018 dollars
Indirect Annual Costs (IDAC) =		$128,268 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC		$254,350 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Operating Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$7,500 in 2018 dollars
Annual Operating Cost =	Operator Labor Rate x Hours/Day x t_{SCR} =	$87,600 in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$3,470 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$21,573 in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$5,939 in 2018 dollars
Direct Annual Cost =		$126,082 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,718 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$125,550 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$128,268 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$254,350 per year in 2018 dollars
NOx Removed =	33 tons/year
Cost Effectiveness =	$7,690 per ton of NOx removed in 2018 dollars

DCP Operating Company, LP
Linam Ranch Gas Plant

Solar Centaur T-4700	Interest Rate:	5.50%
Unit 31	Period (yrs):	20

Base (113 ppm)				
NO_X ppm:		113	ppm	
NO_X lb/hr:		26.03	lb/hr	<-- From 2016 EI calculations
NO_X tpy:		111.53	tpy	<-- From 2016 EI calculations

SoLoNO_X (25 ppm)				
NO_X guarantee:		25	ppm	<-- from Solar
NO_X lb/hr:		5.77	lb/hr	
NO_X tpy:		24.74	tpy	
Total Cap Investment	$	1,377,841		<-- from Solar
Annualized TCI:	$	115,297		<-- Based on interest rate, year and TCI
Annual O&M Costs[1]:	$	153,751		<-- Includes O&M and overhaul costs
Total Annual Costs:	$	269,048		
Emissions Reduction:		86.78	tpy	
Cost Effectiveness:	**$**	**3,100.23**	**$/ton**	

[1] From Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Timeline for Compliance (Docket ID No. EPA-HQ-OAR-2015-0500) Section 3.3.3, Corrected from 1999 to 2018 dollars based on CEPCI. Also includes cost of overhaul as provided by SoLoNO_X.

SCR (34 ppm)				
NO_X guarantee:		34	ppm	<-- Assumed 70% from AP-42 Section 3.1.4.3
NO_X lb/hr:		7.81	lb/hr	
NO_X tpy:		33.46	tpy	
Total Cap Investment	$	1,500,000		<-- Vendor estimate
Annualized TCI:	$	125,519		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	120,508		<-- from Cost Control Spreadsheet
Total Annual Costs:	$	246,027		
Emissions Reduction:		78.07	tpy	
Cost Effectiveness:	**$**	**3,151.46**	**$/ton**	
Incremental Cost:	$	51.22	$/ton	

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine? Industrial

Is the SCR for a new turbine or retrofit of an existing turbine? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	36.80	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,020	Btu/scf
What is the estimated actual annual fuel consumption?	309,156,078	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 3710 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = _____ percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired turbines, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the turbine operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.71	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.21	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	603.1	2018 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh			* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	37	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	316,047,059	scf/Year
Actual Annual fuel consumption (Mactual) =		309,156,078	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.978	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8569	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	18.22	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	78.07	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.88	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	17,043	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	115.02	/hour
Residence Time	1/V_{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		
Elevation Factor (ELEVF) =	14.7 psia/P =	1.14	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia
Retrofit Factor (RF)	Retrofit to existing turbine	1.00	

Not applicable; factor applies only to coal-fired turbines

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	148.18	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	18	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	20	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	4.5	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	7	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	24	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,100	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ =	18.92	kW
	where A = (0.1 x QB) for industrial turbines.	165760.065	kWh/yr
		165.760065	MWh/yr

Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	$1,500,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =		$117,790 in 2018 dollars
Indirect Annual Costs (IDAC) =		$128,268 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC		$246,058 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Operating Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$7,500 in 2018 dollars
Annual Operating Cost =	Operator Labor Rate x Hours/Day x t_{SCR} =	$87,600 in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$8,190 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$10,961 in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$3,540 in 2018 dollars
Direct Annual Cost =		$117,790 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,718 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$125,550 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$128,268 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$246,058	per year in 2018 dollars
NOx Removed =	78	tons/year
Cost Effectiveness =	$3,152	per ton of NOx removed in 2018 dollars

DCP Operating Company, LP
Linam Ranch Gas Plant

Solar Centaur T-4000	Interest Rate:	5.50%
Unit 32B	Period (yrs):	20

Base (102 ppm)

NO_X ppm:		102	ppm	
NO_X lb/hr:		23.72	lb/hr	<-- From 2016 EI calculations
NO_X tpy:		27.87	tpy	<-- From 2016 EI calculations

SoLoNO_X (25 ppm)

NO_X guarantee:		25	ppm	<-- from Solar
NO_X lb/hr:		5.81	lb/hr	
NO_X tpy:		6.83	tpy	
Total Cap Investment	$	1,377,841		<-- from Solar
Annualized TCI:	$	115,297		<-- Based on interest rate, year and TCI
Annual O&M Costs[1]:	$	153,309		<-- Includes O&M and overhaul costs
Total Annual Costs:	$	268,605		
Emissions Reduction:		21.04	tpy	
Cost Effectiveness:	**$**	**12,764.91**	**$/ton**	

[1] From Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Timeline for Compliance (Docket ID No. EPA-HQ-OAR-2015-0500) Section 3.3.3, Corrected from 1999 to 2018 dollars based on CEPCI. Also includes cost of overhaul as provided by SoLoNO_X.

SCR (31 ppm)

NO_X guarantee:		31	ppm	<-- Assumed 70% from AP-42 Section 3.1.4.3
NO_X lb/hr:		7.12	lb/hr	
NO_X tpy:		8.36	tpy	
Total Cap Investment	$	1,500,000		<-- Vendor estimate
Annualized TCI:	$	125,519		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	106,251		<-- from Cost Control Spreadsheet
Total Annual Costs:	$	231,770		
Emissions Reduction:		19.51	tpy	
Cost Effectiveness:	**$**	**11,880.95**	**$/ton**	
Incremental Cost:	$	(883.96)	$/ton	

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine? Industrial

Is the SCR for a new turbine or retrofit of an existing turbine? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	36.21	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,020	Btu/scf
What is the estimated actual annual fuel consumption?	83,425,083	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3710	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = _____ percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired turbines, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the turbine operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.66	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.20	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	603.1	2018 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh			* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	36	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	310,980,309	scf/Year
Actual Annual fuel consumption (Mactual) =		83,425,083	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.268	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	2350	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	16.60	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	19.51	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.88	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	16,770	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	116.84	/hour
Residence Time	1/V_{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.14	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia
Retrofit Factor (RF)	Retrofit to existing turbine	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	143.54	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	17	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	20	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	4.5	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	6	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	22	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,000	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ =	18.62	kW
	where A = (0.1 x QB) for industrial turbines.	163102.6609	kWh/yr
		163.1026609	MWh/yr

Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	$1,500,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =		$103,533 in 2018 dollars
Indirect Annual Costs (IDAC) =		$128,268 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC		$231,801 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Operating Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$7,500 in 2018 dollars
Annual Operating Cost =	Operator Labor Rate x Hours/Day x t_{SCR} =	$87,600 in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$2,046 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$2,958 in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$3,429 in 2018 dollars
Direct Annual Cost =		$103,533 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,718 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$125,550 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$128,268 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =		$231,801 per year in 2018 dollars
NOx Removed =		20 tons/year
Cost Effectiveness =		$11,883 per ton of NOx removed in 2018 dollars

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March 3, 2020

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

Re: NMED Jan. 7, 2020, Request for Additional Information on the Four-Factor Analysis Report
Regional Haze Program
DCP Operating Company, LP – Linam Ranch Gas Plant

Mr. Singleton,

DCP Operating Company, LP (DCP) is in receipt of the New Mexico Environment Department's (NMED's) January 7, 2020, "*Request for Additional Information for Four-Factor Analyses under the Regional Haze Program*" ("Request for Additional Information" or supplemental information request), which requests various and specific supplemental information, technical discussions, analyses, and data, including possible supplemental "Four-Factor Analyses," for multiple sources with respect to DCP's Linam Ranch natural gas processing plant in Lea County, New Mexico. In the time afforded, and given the objections below, this letter provides DCP's responses to the January 2020 Request for Additional Information (in blue font, below).

NMED's January 7, 2020, Request for Additional Information, including potential Four-Factor Analyses, does not state a timeline by when the operator is to provide responsive information, and only states qualitatively to submit responses "as soon as possible." DCP notes that NMED's initial request for Four-Factor Analyses dated July 18, 2019, afforded approximately three and a half months to fulfill NMED's request for responses and analyses, requested by November 1, 2019. Given the level of information expected in NMED's initial request, DCP believes three and a half months was impracticably short, but DCP fulfilled the request to the best of the company's ability. With respect to the January 2020 Request for Additional Information, DCP received a phone call from NMED on February 10, 2020, expecting a response to the supplemental information request and possible Four-Factor Analyses by February 14, 2020, five weeks from NMED's letter of January 7, 2020. February 14, 2020, is unrealistic and unreasonable for the responses requested by NMED. DCP will provide what information it reasonably can by March 3, 2020, and will otherwise provide follow-on requested information when it is reasonable to do so given what is being requested by the agency.

As this is an administrative proceeding with an administrative record, for the record DCP must note any objections it has to the NMED request. DCP states the following objections for the record in relation to NMED's request for Regional Haze-related information and analyses, and preserves its rights related thereto notwithstanding DCP's providing information requested by NMED.

- DCP has limited resources available to respond to NMED's initial, and now supplemental information request; DCP does not have resources available to be dedicated full time to responding to NMED requests analyses, technical discussions, and responding to requests for information. DCP has expended resources, where practicable, to have third party support with respect to the company's responses to NMED's requests for assessments and information, but that support is not always practicable or available, and there are limitations on DCP's use of such third party support. DCP is providing the responses herein, to the agency's supplemental request for information, to the best of the company's ability, in the time afforded, given the limitations of its resources.

- NMED's amount of time afforded to respond to the agency's Request for Additional Information, potentially including Four-Factor Analyses, is impracticably short, unrealistic and unreasonable for a number of the requested items, and affects DCP's ability to respond to the various requests.

- DCP objects to NMED's Request for Additional Information to the extent the requests are for assessments, discussion, information, data that are not presently available and in the possession of the source, in this case DCP. It is within NMED's authority to request information presently available and in the possession of a source operator, but it is beyond the agency's authority to require a source to create or generate information or data that does not presently exist or is not in the possession of the source, or to require a source to expend monies/resources to create or generate such information or data.

- DCP objects to vague, ambiguous or undefined terms in the Request for Additional Information, and objects to the extent the request require DCP to engage in speculation in order to attempt to respond to an agency's stated question or request.

- DCP objects NMED's requests for assessments or analyses that directly or indirectly result in or would relate to "redefining the source," being a properly-authorized, operating, and permitted emissions source. The federal Regional Haze regulation contemplates emissions control technologies that might be cost-effectively retrofitted on a source; redefining a properly-authorized, permitted and operating source is not a retrofit control technology, and is beyond the authority of the Regional Haze rule to consider as a Reasonable Progress measure.

- DCP objects to the fact that NMED has not provided, as part of this administrative process, the cost-effectiveness threshold for control technologies for the Regional Haze Reasonable Progress rulemaking.

- DCP objects to the agency's fundamental threshold for requesting 4-Factor Analyses from sources in the State, *i.e.*, Q/d of 5, as this is unreasonably stringent and requiring resource expenditures for assessments of sources that would not effectively contribute to visibility improvement in Class I areas. The State of Colorado applied a Q/d of 20 as its screening criteria, which assumed an estimated associated deciview improvement of 0.3; a Q/d of 5 would provide, presumably, one-quarter of the assumed visibility improvement, so requiring screening of sources at that level that would provide potentially, *e.g.*, 0.07 deciview improvement.

Preserving the objections noted, above, DCP responds to the agency's January 7, 2020, Request for Additional Information as follows (NMED Jan. 7, 2020, requests re-stated in black font, and DCP responses provided in **blue** font).

Please provide the following information for the units that were evaluated in four-factor analysis for potential nitrogen oxides (NO_X) controls.

Flares

Thank you for providing the flaring supplement to the four-factor analysis for startup, shutdown, and/or maintenance (SSM) flaring emissions. The Department still requires the following information for the flares at the DCP Midstream Linam Gas Plant, Unit Numbers 2, 4A and AGI Flare.

1. Provide a description of each flare, the design and type, and its purpose.

   Unit No. 2 (Amine Acid Gas Flare) and Unit No. AGI Flare are both in service providing both emergency as well as startup, shutdown, maintenance/malfunction ("SSM&M") flare function for Linam Ranch Gas Plant's ("Linam Ranch's") acid gas service. Both flares will flare pilot, purge, assist gas and any acid gas flow to the flare that results from SSM&M and other emergency events.

   Unit No. 4A (ESD Flare) serves as an emergency/SSM&M flare and as a process flare to Linam Ranch. The ESD flare will flare pilot, purge, and emission from TEG dehydrator during steady state operations and any gas flow to the flare that results from SSM&M and other emergency events.

   Refer to *Attachment A – Process Flow Diagram and Flare Emission Calculation* as reference.

2. List and describe the reasons that trigger each type of flaring event.

   Steady-state emission from the flares are represented on *Attachment A*.

   Other flaring events include permit-authorized planned SSM flaring events and unplanned flaring events, *e.g.*, malfunction-related or emergency flaring events. Planned SSM flaring events are triggered by routine maintenance at frequencies recommended by the manufacturer or as regularly scheduled by DCP as part of planned maintenance. Allowable emission limits in the facility's air permit represent the maximum amount of emissions authorized to occur during planned maintenance activities and startup/shutdown events anticipated pre- and post-maintenance. However, these planned maintenance events do not occur at the same sequence or frequency generally reflected in a permit, *i.e*. quarterly, annually, biennially, etc., therefore, actual emissions that occur at the facility can differ each year as represented in DCP's process and SSM flaring four factor analysis report submitted on December 16, 2019.

   Unplanned flaring events are triggered for various unforeseeable, unexpected or unpredictable reasons, such as equipment malfunction, third party power loss, emergencies, *etc*. Excess emission resulting from these events, to the extent they are not reflected in the facility air permit SMM&M allotment, are reported to NMED pursuant to NMAC 20.2.7.110. DCP operates its process equipment and emission control equipment in a manner consistent with good air pollution control practices for minimizing emissions, including minimizing to the extent practicable the duration of unplanned flaring events and the volume of material subjected to such flaring.

3. Discuss potential alternative control options or operational changes that could reduce nitrogen oxides (NO_X) and/or sulfur dioxide (SO_2) flaring emissions, including:

DCP objects to this question 3 to the extent it uses ambiguous or undefined terms, requires speculation, and for the objections referenced above. Preserving those objections, DCP responds as follows.

a. infrastructure that allows re-routing or recirculating the gas within the facility or outside of the facility until an SSM event is over;

Linam Ranch's current infrastructure supports nat. gas re-routing, and off-loading when feasible under certain circumstances, each of which serve to reduce flaring emissions. Linam Ranch has the ability, when necessary, to close the nat. gas inlet to the facility, which significantly limits or prevents flaring at the facility. Linam Ranch also coordinates with the producers, either prior to a planned event, or when feasible during an unplanned event, to temporarily re-route nat. gas to other facilities if practicable or to shut in nat. gas for a finite period, to reduce the volume of nat. gas potentially subjected to flaring at the facility. Under certain circumstances DCP can, and does, utilize producer temporary off-load capabilities, or DCP capability to temporarily re-route gas when practicable and feasible, to minimize the volume of nat. gas potentially subjected to flaring at the facility. DCP believes that these capabilities and measures, taken together, serve to prevent flaring at the Linam Ranch facility or to mitigate the duration of a flaring event or the volume of material subjected to flaring. DCP is not aware of another technically feasible option to appreciably further reduce flaring events or volumes at the facility. DCP would note that with its operational practices and improvements Linam Ranch has operated within its permitted SSM&M flaring parameters in the last year, and has had minimal or no unanticipated, e.g., malfunction- or third party-related flaring events, so flaring at the facility has been positively managed.

b. sulfur absorbent technology used to remove sulfur from pipelines and other auxiliary equipment to reduce inlet or plant flaring SO_2 emissions;

The Linam Ranch nat. gas processing plant receives, and is designed to receive, high hydrogen sulfide ("H2S") concentration natural gas, referred to as "sour" nat. gas. Given the high H2S concentration received by the Linam Ranch plant, an amine treatment system is the most effective and the only technology that is technically feasible to remove sulfur and treat the sour gas stream of this volume and concentration.

Other sulfur absorbent technology, such as pipeline additive injection, commonly referred to as hydrogen sulfide scavenger, is utilized only non-sour gas systems, meaning on what are known as "sweet" gas streams, in order to treat very small amounts of hydrogen sulfide that might exist in a sweet gas stream to meet a certain specification, and are not suitable or effective for treating the sour gas stream processed at Linam Ranch; they would not meaningfully reduce the concentration of H2S that would recognizably affect the amount of sulfur received by the Linam Ranch plant.

c. Gas Capture Plans with facilities located downstream and upstream similar to those required for producers to better synchronize upstream and downstream services with the facility;

DCP objects to the use of an ambiguous or undefined term with respect to a midstream nat. gas processing plant facility, and to the extent this question requires speculation. A Gas Capture Plan is a New Mexico Oil Conservation Division ("NMOCD") requirement for producer entities, for the producer's production development, to ensure communication between the producer entity and gatherer in order to improve communication and planning future nat. gas takeaway capacity, in order to mitigate the potential for a producer entity having to flare what would be stranded gas at its well production facility if there weren't nat. gas takeaway. DCP as a midstream entity does confer with producers about the producer's Gas Capture Plans. The concept, however, has no applicability to a midstream nat. gas processing plant as such a facility, for example the Linam Ranch plant, is by definition designed to receive and process the producer's nat. gas; DCP's Linam Ranch gas plant does not flare nat. gas due to lacking capacity, for example, so the concept is not applicable to a midstream gas processing plant.

d. use of remote capture equipment;

DCP objects to the use of an ambiguous or undefined term with respect to a midstream nat. gas processing plant facility, and to the extent this question requires speculation. Remote capture equipment, as DCP understands it from NM agency materials, is a concept that relates to and provides capability at a producer wellhead and relates to wellhead volumes of nat. gas and nat. gas products (liquids) at the producer wellhead. The same concept does not have applicability to a midstream nat. gas processing facility, and the type of technology is not applicable at the scale of a nat. gas processing facility; a midstream nat. gas processing plant, by definition, is removing nat. gas products (liquids) from the inlet material, which is one of its functions.

e. better infrastructure planning and changes to existing infrastructure that connects the downstream and upstream operations to DCP facilities to ensure that there is adequate processing capacity to move produced gas to market.

DCP objects to the use of ambiguous or undefined terms, and to the extent this question requires speculation. As described in the prior responses, DCP's Linam Ranch nat. gas plant processing capacity appropriately and adequately manages relevant producer nat. gas production; the plant does not flare nat. gas due to lacking capacity.

Note that flaring at an up or downstream facility to avoid flaring at the Linam Gas Plant is not considered to be an actual reduction in flared emissions rates under the four-factor analysis.

4. For any technically feasible solutions, provide a four-factor analysis. For additional information regarding potential alternative controls to flaring see the New Mexico Methane Strategy website: https://www.env.nm.gov/new-mexico-methane-strategy/methane-advisory-panel/.

Considering the above requests, DCP is not aware of any additional flaring technology or relevant operational changes that are technically feasible.

5. DCP states in its December 16th letter that "since the sources of SSM emission originates from normal plant activities….notes that it's impractical to employ such measure in order to decrease flaring…and the facility has an existing BMP *[best management practices]* process"….DCP concludes that there are no reasonable nor technically feasible emission reduction measure for flare sources ……" Provide details of the existing BMPs employed at the facility to reduce flaring emissions.

The referenced passage, above, refers to planned/routine SSM events. Facility equipment has routine maintenance schedules in order to maintain the equipment in good working order.

Examples of existing BMPs employed at the Linam Ranch Plant to reduce flaring during planned/routine SSM events includes:

- Coordination/communication between upstream entities (producers), DCP, and downstream entities and facilities prior to and during planned outages to minimize volumes of nat. gas directed to the Linam Ranch nat. gas plant during these events.
- When practicable and feasible, DCP temporary re-routing of upstream nat. gas to other DCP facilities.
- When practicable and feasible, producer or DCP use of nat. gas off-load agreements to temporarily route upstream nat. gas to third party facilities.
- Actions at the facility to minimize the duration/number of SSM events and volume flared through:
    - Critical Spare Program to ensure necessary equipment is on site and lacking such does not delay to duration of a planned event.
    - Coordination between operation and maintenance teams to ensure efficient implementation of a planned event.
    - DCP tracks and documents all work orders for needed maintenance or repairs through an asset management software to ensure that necessary work orders are executed appropriately and on time, which reduces the likelihood of having to have an off-cycle turnaround or maintenance event and associated SSM flaring.

6. The allowable flaring emission limits for NO_X are all less than 5 tons per year (TPY) and Unit AGI Flare has a limit less than 5 tpy for SO_2 which are less that the threshold that NMED established for sources to submit a four-factor analysis. However, in 2016, actual emissions reported for each flare exceeded their allowable limits and DCP's emissions inventory for years 2014 through 2018 show that the AGI flare and amine plant flare consistently exceeded allowable limits. (See Table 1.) Please explain the discrepancy between the SSM SO_2 emissions provided in the supplemental flaring analysis and NMED's 2016 emissions inventory. As the permitted limits do not reflect actual operations at the facility, please resubmit the four-factor analysis for the flares based on actual emissions reported in 2016. (See Table 1.)

Table 1 SSM Flare Emission Rates and Limits		
Flare Unit	NO_X tpy	SO_2 tpy
Emission Limits		
2	0.51	46.0
4A	3.3	18.9
AGI Flare	0.34	4.06
Emissions reported in 2016 Emissions Inventory		
2	1.84	26.97
4A	0.09	35.86
AGI Flare	1.84	242.85
Emissions Reflected in Four-Factor Supplement Dec 16, 2019		
2	0	3.28
AGI Flare	0	0
Malfunction	0.04	9.79

The SSM SO2 emission amount described in DCP's Dec. 16, 2019, letter only refers to authorized/permitted emissions and does not include reported excess emissions resulting from unforeseeable or unplanned, *e.g.*, malfunction-related events. Table 2 of the December 16, 2019 submitted response is titled "2016 EIQ Reported **Process Flaring** and **SSM Flaring** Emission".

The reported excess emissions not included in the above table can differ from year to year and are, by nature, unforeseeable/unanticipated. These events are addressed through facility's continuous improvement efforts to reduce such events by, for example, identifying causes and addressing them through equipment investments and/or operational improvements. As a result, Linam Ranch had zero excess emission events since February 10, 2019, and recently celebrated one year without an excess emission event.

Turbines

1. Provide documentation from Solar that they do not manufacture turbines with steam injection technology and that the Centaur 40 is not capable of being retrofitted to accept this technology.

   Please reference DCP's original November 2019 four factor analysis report on this topic. The report does not indicate that the Solar Turbine is not capable of being retrofitted to accept this technology, but rather states that "[s]team injection is not discussed as an option for these Solar turbines at Linam because Solar does not manufacture turbines with steam injection technology", meaning Solar no longer offers steam injection retrofit packages because they are obsolete. Please refer to *Attachment B – Solar Wet NOx Letter*, which states that Solar does not offer Wet-NOx technology.

2. Consider and include a discussion of the technical feasibility of other types of catalytic combustion, such as XONON^{TM} developed by Catalytic Combustion Systems, Inc.

   DCP objects to the use of an ambiguous or undefined term or phrase, and to the extent this question requires speculation. DCP is not familiar with the referenced technology, and therefore cannot offer any concrete opinion on its potential technical feasibility on these

particular turbines. Given the time limitation for this request, DCP was unable to and did not initiate a discussion between DCP's engineering and operations functions with the XONON technology manufacturer with whom the agency is suggesting DCP speak. DCP has no knowledge of this technology being applied in nat. gas midstream industry service.

3. Provide more detail of the Good Combustion Practices that have been implemented on the turbines, including routine inspections, maintenance and training schedules. It is unclear if these practices are fully optimized or conform to permit conditions alone.

DCP objects to the use of an ambiguous or undefined term or phrase, and to the extent this question requires speculation. The turbines at Linam Ranch are equipped with additional monitoring hardware, which provides live data allowing monitoring of equipment health. DCP has historically used the monitoring service offered by OEM vendor, Solar, which affords strong routine inspection and maintenance practices on the turbines. DCP is in the process of transitioning the monitoring service to DCP's internal reliability group. Routine inspection and maintenance activities, such as daily visual inspection, water wash, borescope inspection, and all other interval preventive maintenance activities, are tracked through DCP's asset management/maintenance software to ensure that they are executed appropriately and timely. In addition, Solar technicians are brought in to supervise DCP's turbine technicians when performing major maintenance or overhauls.

4. Please consider and include a discussion on the feasibility of replacing the natural gas-fueled turbines with commercial electric powered turbines.

DCP objects to this request as it pre-supposes re-definition of the facility process equipment, in this case properly authorized, permitted, and operating nat. gas-fired turbines – re-defining a source is not a retrofit control technology, and is beyond the authority of the Regional Haze rule to consider as a Reasonable Progress measure. Accordingly, it is not required that DCP discuss this topic.

Without waiving objections, the replacement of the existing natural gas-fueled turbines with electric compressor motors are not technically feasible with existing infrastructure at Linam Ranch. The four turbines subject to the Four Factor Analysis (Units 29, 30, 31 and 32B) have total site rating horsepower of 28,291 HP. Accommodating nearly 30,000 HP electric motor capacity is not feasible with the present electric infrastructure at Linam Ranch, would require significant electric power supply analysis, and would, for example, potentially require construction of a new 100 MW substation.
Construction of a substation does not guarantee electricity, which would depend on generation capacity and, for example, whether or not the conductors need to be resized to handle the load. Exclusive of cost considerations, including consideration of the cost of electric power supply on a regular basis for this HP equivalent, technical feasibility would require a feasibility study by XCEL Energy, which can take longer than 18-24 Months.

Please refer to *Attachment C – Priority Power Discussion*.

5. Provide copies of vendor quotes used to determine the cost of compliance.

DCP notes that in its initial report provided a vendor estimate of expected costs for retrofitting existing turbines; this was not a vendor quote providing more accuracy with respect to costs, and it is what was available in the time provided.

Please refer to *Attachment D – SoLoNOx and SCR estimate*

Engines

1. Provide more detail of the Good Combustion Practices that have been implemented on the two-stroke lean-burn (2SLB) engines, including routine inspections, maintenance and training schedules. It is unclear if these practices are fully optimized or conform to permit conditions alone.

   DCP objects to the use of an ambiguous or undefined term or phrase, and to the extent this question requires speculation. Linam's two-stroke lean-burn (2SLB) engine's Good Combustion Practices includes routine inspection and preventative maintenance. Also, prior to every quarterly preventative maintenance, DCP use specialized tool to monitor engine running condition and check for presence of any abnormal vibration. Routine inspection and all interval PM activities are tracked through DCP's asset management and maintenance system to ensure they are implemented appropriately and in a timely manner. Inspection/Maintenance is appropriately optimized for the emission units based on DCP's long history/experience operating such engines.

2. Provide more detail on why the age of the 2SLB engines prohibits retrofitting these units with Clean Burn Technology, including a discussion on why the installation of high energy ignition systems (HEIS) is not feasible. It would be beneficial to submit detailed documentation from the vendor on why none of the CBT options is technically feasible.

   Referencing the initial four factor analysis report submitted for Linam Ranch, the report states that "*2SLB engines are mechanically capable of being retrofit with more sensitive air-to-fuel ratio controllers and running on higher air-to-fuel ratio combustion to control NOX emissions. However, based on the advanced age, type of engine,* ***and discussion with vendor****, DCP has determined that clean burn technology retrofits are physically possible yet deemed technically infeasible for the engines at Linam*."

   Above statement was based on discussion with the vendor, but also with DCP's experienced asset engineers – due to the type and vintage of these particular 2SLB engines, any clean burn retrofit technology would (i) require detailed studies/evaluations of each engine for custom retrofit specific to these engines, and (ii) while hypothetically feasible, such retrofits for this type and vintage engines would be so extensive and invasive that they would be as or more uneconomical than a new engine, so the retrofit emissions control technology is deemed impracticable, otherwise infeasible, for these particular engines.
   DCP believes a retrofit control technology is infeasible and beyond the scope of the Regional Haze rule if the cost of the control technology exceeds the cost of the base authorized/permitted emissions source; with the time limitations afforded, DCP was not able to develop further analyses and details on potential CBT retrofit actions for these particular 2SLB engines.

3. The report references AP-42 Section 3.2 that identifies Selective Catalytic Reduction (SCR) as an available control technology for 2SLB engines. Provide supporting data and information for the determination that SCR systems may result in technical complications and unreliable operation. Documentation from the equipment vendor detailing the technical drawbacks to this technology and the preferred technology for NO_X would be beneficial.

   Please refer to *Attachment E – Engine SCR vendor discussion*.

   After further discussion over the phone with the vendor representative, if an SCR were applied to these 2SLB engines the vendor is not able to guarantee life of catalyst nor accurate emission reduction that SCR system would be intended to achieve. DCP's facility engineer indicates that backpressures imposed by the SCR system will result in de-rated output of the unit. Therefore, DCP deemed this technology too uncertain, and fundamentally affecting the authorized equipment, to be considered as technically feasible control technology for engines at Linam Ranch.

4. The report states that the exhaust oxygen levels for 2SLB engines are not sufficiently low to support that occur during non-selective catalytic reduction (NSCR). Has DCP Midstream verified the average exhaust oxygen levels from each stack to support this assertion?

   DCP has data reflecting exhaust oxygen levels for these engines verified by data in third party stack test reports. Please refer to *Attachment F – EU 10 & 11 Stack Test Report.* These exhaust oxygen levels reflect oxygen levels that are too high to accommodate an NSCR process. There is no requirement to verify average exhaust oxygen levels, so it is unreasonable to expect such is available.

5. Consider and include a discussion on the feasibility and cost of technology that limits engine capacity to reduce NO_X emissions.

   DCP objects to the use of an ambiguous or undefined term or phrase, and to the extent this question requires speculation. DCP objects to the extent it does not understand the retrofit technology referred to. DCP objects to this request as it may pre-suppose re-definition of the facility process equipment (*e.g.*, limiting engine capacity), in this case properly authorized, permitted, and operating nat. gas-fired engines – re-defining a source is not a retrofit control technology, and is beyond the authority of the Regional Haze rule to consider as a Reasonable Progress measure. Accordingly, it is not required that DCP discuss this topic.

6. Please consider and include a discussion on the feasibility of replacing the natural gas-fueled engines with commercial electric powered compressors.

   DCP objects to this request as it pre-supposes re-definition of the facility process equipment, in this case properly authorized, permitted, and operating nat. gas-fired engines – re-defining a source is not a retrofit control technology, and is beyond the authority of the Regional Haze rule to consider as a Reasonable Progress measure. Accordingly, it is not required that DCP discuss this topic. Without waiving objections, the Linam Ranch gas plant's existing infrastructure does not support replacement of nearly 10,000 HP natural gas-fueled engines with electric driven motors. Please refer to discussion provided on Turbine question 4.

7. Provide copies of vendor quotes used to determine the cost of compliance.

   There are no vendor quotes used for the engines at Linam Ranch.

8. Provide the electronic spreadsheets used for control cost calculations.

   There are no cost calculation spreadsheets for the engines at Linam Ranch.

If you have any questions on the specific responses provided, please feel free to contact me directly by phone at 432-215-8514 or via email at hshong@dcpmidstream.com.

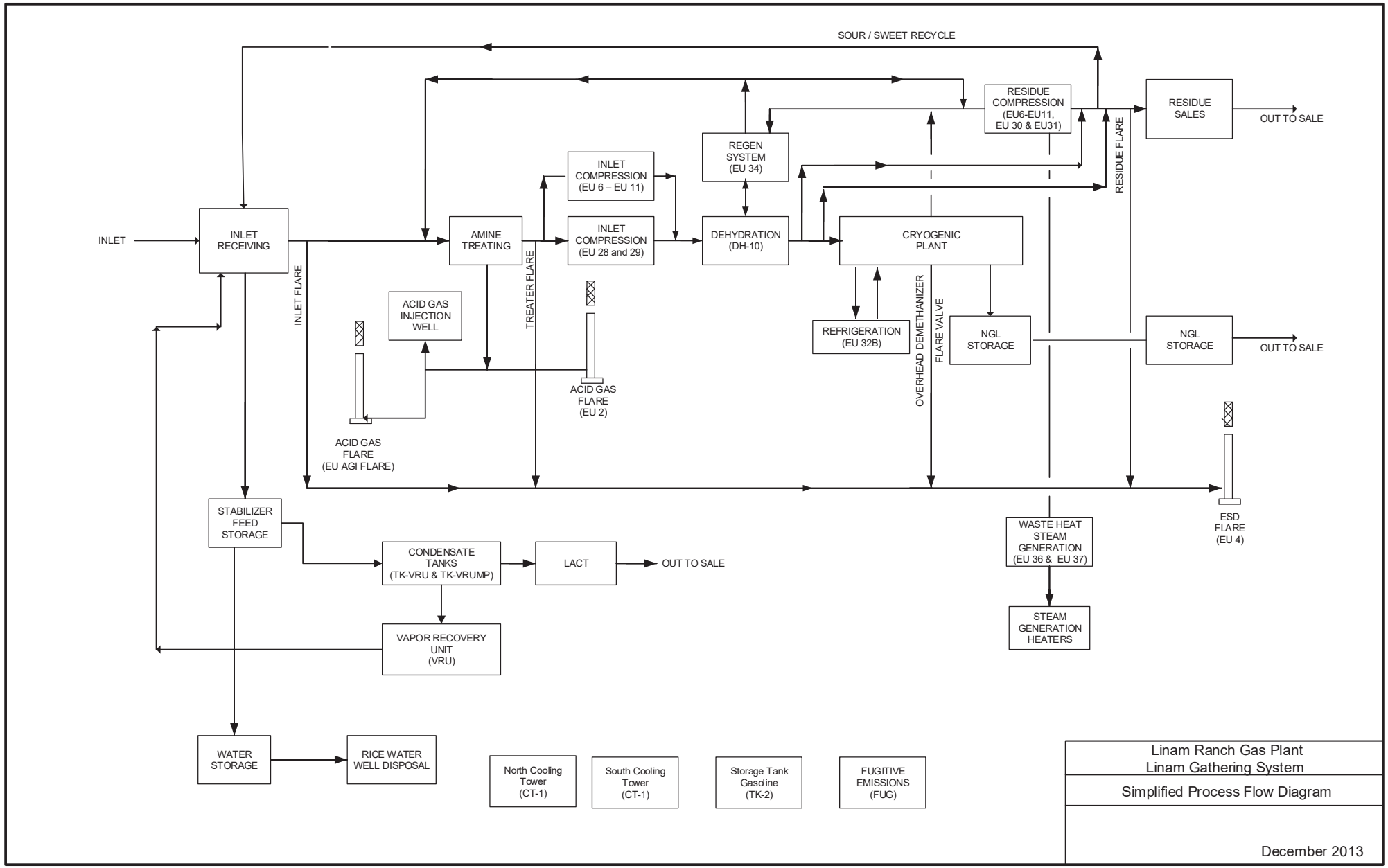
Sincerely,



Sam Hong
Environmental Engineer
DCP Midstream, LP

Enclosures

Attachment A – Process Flow Diagram and Flare Emission Calculation


SOUR / SWEET RECYCLE
INLET
INLET RECEIVING
INLET FLARE
AMINE TREATING
TREATER FLARE
INLET COMPRESSION (EU 6 – EU 11)
INLET COMPRESSION (EU 28 and 29)
REGEN SYSTEM (EU 34)
DEHYDRATION (DH-10)
RESIDUE COMPRESSION (EU6-EU11, EU 30 & EU31)
RESIDUE SALES
OUT TO SALE
RESIDUE FLARE
CRYOGENIC PLANT
OVERHEAD DEMETHANIZER
FLARE VALVE
REFRIGERATION (EU 32B)
NGL STORAGE
NGL STORAGE
OUT TO SALE
ACID GAS INJECTION WELL
ACID GAS FLARE (EU 2)
ACID GAS FLARE (EU AGI FLARE)
ESD FLARE (EU 4)
STABILIZER FEED STORAGE
CONDENSATE TANKS (TK-VRU & TK-VRUMP)
LACT
OUT TO SALE
VAPOR RECOVERY UNIT (VRU)
WASTE HEAT STEAM GENERATION (EU 36 & EU 37)
STEAM GENERATION HEATERS
WATER STORAGE
RICE WATER WELL DISPOSAL
North Cooling Tower (CT-1)
South Cooling Tower (CT-1)
Storage Tank Gasoline (TK-2)
FUGITIVE EMISSIONS (FUG)
Linam Ranch Gas Plant
Linam Gathering System
Simplified Process Flow Diagram
December 2013

E. Amine Unit Acid Gas Flare- Acid Gas Analysis (per 11/4/13 DCP Email)

Emission Unit: Acid Gas Flare

Estimated Flared Gas Composition Used for Calculations

Component	MW	Flared Gas[1] Mol%	MW * wet vol %	HHV Btu/scf[2]	Btu/scf * wet vol %	Mass Fraction (wet)	Spec. Volume[2] ft^3/lb	Spec. Volume VOC ft^3/lb
Water	18.02	1.13%	0.20	0.0	0.0	0.00	21.06	
Hydrogen Sulfide	34.08	18.71%	6.38	637.02	119.2	0.15	11.136	
Carbon Dioxide	44.01	80.65%	35.50	0.0	0.0	0.84	8.623	
Nitrogen	28.01	0.01%	0.00	0.0	0.0	0.00	13.547	
Oxygen	32.00	0.00%	0.00	0.0	0.0	0.00	11.859	
Methane	16.04	0.36%	0.06	1009.7	3.6	0.00	23.65	
Ethane	30.07	0.08%	0.02	1768.7	1.4	0.00	12.62	
Propane	44.10	0.03%	0.02	2517.2	0.9	0.00	8.606	1.094
i-Butane	58.12	0.06%	0.03	3252.6	1.8	0.00	6.529	1.790
n-Butane	58.12	0.02%	0.01	3262	0.8	0.00	6.529	0.764
i-Pentane	72.15	0.01%	0.00	3999.7	0.2	0.00	5.26	0.167
n-Pentane	72.15	0.01%	0.01	4008.7	0.3	0.00	5.26	0.266
Hexanes	86.18	0.05%	0.05	4756.1	2.6	0.00	4.404	1.759
		101%	42.28		130.9	1.00		5.840
NMNEHC (VOC)		0.2%				0.3%		

[1] *Based on DCP's recent 11/1/13 Linam Ranch Acid Gas Flare Gas Analysis to provide conservative estimates for sulfur dioxide and heat release estimate.*

[2] *Component HHVs and specific volumes obtained from Physical Properties of Hydrocarbons, API Research Project 44, Fig. 16-1, Rev. 1981.*

Fuel Data

Flare Pilot	500	scf/hr	Engineering judgement
	0.00050	MMscf/hr	
	1000	Btu/scf	Pipeline Gas, HHV, nominal
	0.50	MMBtu/hr	MMscf/hr * Btu/scf
Purge Gas	16	Mscf/day	per DCP Midstream (Jennifer Corser 10/29/13 email)
	0.67	Mscf/hr	Mscf/d / 24 hr/day
	0.001	MMscf/hr	Mscf/hr / 1000
	1000	Btu/scf	Pipeline Gas, HHV, nominal from Linam T5 app.
	0.67	MMBtu/hr	MMscf/hr * Btu/scf
Assist Gas			
	135	Btu/scf	Heating value of Pilot + Purge gas + Flared gas
	500	Btu/scf	target heat content
	1000	Btu/scf	Assist gas-assumed sweet
	0.18	MMscf/hr	Assist gas volume
	182.5	MMBtu/hr	Assist gas heat input
Assist gas - Annual*	5.0	MMscf/yr	Estimated Maximum annual SSM flow rate. Not a requested limit; for calculation only.

Note: Flared gas annual/ ratio of assist gas: flared gas hourly usage) ex: 10.5 MMscf/yr / (1-.8054)

Flared Gas - Short Term	0.25	MMscf/hr	High end representative SSM hourly flowrate taken from 2010 - 2013 Blowdown Data for Unit 2
	131	Btu/scf	Heating value calculated from gas compostion above.
	33	MMBtu/hr	Hourly heat rate = Heating value * Effective hourly flow rate.
Flared Gas - Annual	2.9	MMscf/yr	Estimated Maximum annual SSM flow rate. Taken from avg of 2010 - 2013 SSM blowdown data for Linam Ranch GP. Not a requested limit; for calculation only.
Total	216	MMBtu/hr	**Pilot + Purge gas + Flared gas**

Stack Parameters

	1,832	°F	Exhaust temperature	
	65.6	ft/sec	Exhaust velocity	
	222.0	ft	Flare height	
Pilot+ Purge Gas only				
	16.04	g/mol	Pilot & Purge gas molecular weight	Mol. wt. of methane, the dominant species
	81,667	cal/sec	Heat release (q)	$MMBtu/hr * 10^6 * 252 cal/Btu \div 3600 sec/hr$
	65,967		q_n	$q_n = q(1-0.048(MW)^{1/2})$
	0.26	m	Effective stack diameter (D)	$D = (10^{-6}q_n)^{1/2}$
Pilot + Purge Gas+ Flared Gas + Assist Gas				
	42.16	g/mol	Flared gas molecular weight	Volume weighted mol. wt. of all components
	1.52E+07	cal/sec	Heat release (q)	$MMBtu/hr * 10^6 * 252 cal/Btu \div 3600 sec/hr$
	1.04E+07		q_n	$q_n = q(1-0.048(MW)^{1/2})$
	3.23	m	Effective stack diameter (D)	$D = (10^{-6}q_n)^{1/2}$

E. Amine Unit Acid Gas Flare- Acid Gas Analysis (per 11/4/13 DCP Email)

Emission Unit: Acid Gas Flare

Emission Rates

Pilot+ Purge Gas

NOx	CO	VOC	H_2S	SO_2	Units	
0.068	0.370				lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
			3.6E-04		lb H_2S/Mscf	Purchased sweet natural gas fuel, 0.25 gr H_2S/100scf
			4.2E-04		lb H_2S/hr	H_2S rate * fuel usage
				7.1E-03	lb S/Mscf	Sweet natural gas fuel, 5 gr S/100scf
				8.3E-03	lb SO_2/hr	SO_2 rate * fuel usage
		0.00%			mol%	Assume no VOC content in purchased fuel (methane)
		23.7			ft^3/lb	Specific volume (methane)
		0.00			lb/hr	vol. Gas * mole fraction / specific volume
100%	100%	100%	100%	100%	%	Safety Factor
0.14	0.74				lb/MMBtu	Unit emission rate with Safety Factor
0.16	**0.86**				lb/hr	lb/MMBtu * MMBtu/hr
		-	**1.7E-05**	**1.7E-02**	lb/hr	98% combustion H_2S; 100% conversion to SO_2
0.69	**3.8**	-	**7.3E-05**	**7.3E-02**	tpy	8760 hrs/yr

Assist gas

NOx	CO	VOC	H_2S	SO_2	Units	
0.0680	0.3700				lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
			4E-04		lb H_2S/Mscf	Purchased sweet natural gas fuel, 0.25 gr H_2S/100scf
			6.52E-02		lb H_2S/hr	H_2S rate * fuel usage
				7.1E-03	lb S/Mscf	Purchased sweet natural gas fuel, 5 gr S/100scf
				1.3	lb SO_2/hr	SO_2 rate * fuel usage
		0.00%			mol%	Assume no VOC content in purchased fuel (methane)
		23.7			ft^3/lb	Specific volume (methane)
		0.000			lb/hr	vol. Gas * mole fraction / specific volume
12.4	**67.5**				lb/hr	lb/MMBtu * MMBtu/hr
		-	**1.3E-03**	**1.3**	lb/hr	98% combustion H_2S; 100% conversion to SO_2
0.17	**0.92**	-	**1.8E-05**	**0.018**	tpy	

Flared Gas

NOx	CO	VOC	H_2S	SO_2	Total HAPs	Units	
0.068	0.370					lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
		0.18%	0.187		0.05%	mol%	Flare Gas
		5.8	11.1		4.4	ft^3/lb	Specific volume
		77.9	4201		31.1	lb/hr	vol. Gas * mole fraction / specific volume
2.2	12.1					lb/hr	lb/MMBtu * MMBtu/hr
2.2	**12**	**78**	**4201**	**7750**	**31**	**lb/hr**	Uncontrolled emissions at maximum rate
0.013	**0.070**	**0.45**	**24**	**46**	**0.18**	**tpy**	

Controlled #2 Acid Gas Flare	NOx	CO	VOC	H_2S	SO_2	HAPs	Units
Pilot + Purge Gas+ Flared Gas	**14.9**	**80.6**	**1.6**	**84.0**	**7751**	**0.62**	lb/hr
	0.88	**4.8**	**0.0090**	**0.48**	**45.6**	**0.0036**	tpy

Total HAPs conservatively assumed to be Hexanes+

GHG Emissions

	CO_2e Short Tons/yr		
CO_2	137	Eq 4-15	API Compendium
CH_4	1.1E-03	Eq 4-16	API Compendium
N_2O	4.8E-06	Eq 4-17	API Compendium
Total CO2e	**137**		

DCP Operating Company, LP - Linam Ranch Gas Plant

ESD Flare- per 11/11/13 Extended Inlet Gas Analysis

Emission Unit: ESD Flare

Estimated Flared Gas Composition Used for Calculations

Component	MW	Flared Gas[1] Mol%	MW * wet vol %	HHV Btu/scf[2]	Btu/scf * wet vol %	Mass Fraction (wet)	Spec. Volume[2] ft^3/lb	Spec. Volume VOC ft^3/lb
Water	18.02	0.00%	0.00	0.0	0.0	0.00	21.06	
Hydrogen Sulfide	34.08	0.38%	0.13	637.02	2.4	0.01	11.136	
Carbon Dioxide	44.01	1.61%	0.71	0.0	0.0	0.03	8.623	
Nitrogen	28.01	2.46%	0.69	0.0	0.0	0.03	13.547	
Oxygen	32.00	0.00%	0.00	0.0	0.0	0.00	11.859	
Methane	16.04	73.54%	11.80	1009.7	742.5	0.54	23.65	
Ethane	30.07	12.59%	3.78	1768.7	222.6	0.17	12.62	
Propane	44.10	6.15%	2.71	2517.2	154.7	0.12	8.606	4.863
i-Butane	58.12	0.70%	0.40	3252.6	22.6	0.02	6.529	0.551
n-Butane	58.12	1.62%	0.94	3262	52.8	0.04	6.529	1.281
n- & iso-Pentanes	72.15	0.65%	0.47	3999.7	25.9	0.02	5.26	0.512
Cyclopentane	70.14	0.03%	0.02	4008.7	1.1	0.00	5.26	0.022
C6 HCs	86.18	0.15%	0.13	4747.3	7.1	0.006	4.404	0.118
C7 HCs	100.21	0.04%	0.04	5498.6	2.4	0.002	3.787	0.035
C8 HCs	114.23	0.01%	0.01	6248.9	0.3	0.0003	3.322	0.004
C9 HCs	128.26	0.00%	0.00	6996.3	0.1	0.0001	2.959	0.001
n-Hexane	86.18	0.05%	0.05	4756.1	2.6	0.00213	4.404	0.043
Benzene	78.11	0.03%	0.02	3741.9	1.0	0.00098	4.858	0.022
Toluene	92.14	0.01%	0.01	4474.8	0.3	0.00024	4.119	0.004
Ethyl Benzene	106.17	0.0001%	0.00	5222.1	0.0	0.000005	3.574	0.000
Xylenes	106.17	0.0002%	0.00	5207.8	0.0	0.00001	3.574	0.000
		100%	21.91		1238.6	1.00		7.456
NMNEHC (VOC)		9.4%				21.9%		

[1] *Based on DCP's recent 11/11/13 Linam Ranch inlet gas analysis from 11/6/13 sample to provide accurate estimates for sulfur dioxide and heat release.*

[2] *Component HHVs and specific volumes obtained from Physical Properties of Hydrocarbons, API Research Project 44, Fig. 16-1, Rev. 1981.*

Fuel Data

Flare Pilot	500	scf/hr	Engineering judgement
	0.00050	MMscf/hr	
	1000	Btu/scf	Pipeline Gas, HHV, nominal from Linam T5 app.
	0.50	MMBtu/hr	MMscf/hr * Btu/scf
Purge Gas	63.8	Mscf/day	per DCP Midstream (Jennifer Corser 10/29/13 email)
	2.7	Mscf/hr	Mscf/d / 24 hr/day
	0.0027	MMscf/hr	Mscf/hr / 1000
	1000	Btu/scf	Pipeline Gas, HHV, nominal from Linam T5 app.
	2.7	MMBtu/hr	MMscf/hr * Btu/scf
Flared Gas - Short Term	3.410	MMscf/hr	Maximum Effective hourly flowrate taken from 2010 - 2013 Blowdown Data for AGI Flare
	1,239	Btu/scf	Heating value calculated from gas compostion above.
	4,224	MMBtu/hr	Hourly heat rate = Heating value * Effective hourly flow rate.
Flared Gas - Annual	58.2	MMscf/yr	Estimated Maximum annual SSM flow rate. Taken from avg of 2010 - 2013 SSM blowdown data for Linam Ranch GP. Not a requested limit; for calculation only.
Total	4227	MMBtu/hr	**Pilot + Purge gas + Flared gas**

Stack Parameters

	1,832	˚F	Exhaust temperature
	65.6	ft/sec	Exhaust velocity
	175.0	ft	Flare height
Pilot+ Purge Gas only			
	16.04	g/mol	Pilot & Purge gas molecular weight

Per Linam 2-H sheet

Per Linam 2-H sheet

Mol. wt. of methane, the dominant species

DCP Operating Company, LP - Linam Ranch Gas Plant

ESD Flare- per 11/11/13 Extended Inlet Gas Analysis

Emission Unit: ESD Flare

221,083	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
178,582		q_n	$q_n = q(1\text{-}0.048(MW)^{1/2})$
0.42	m	Effective stack diameter (D)	$D = (10^{-6}q_n)^{1/2}$

Pilot + Purge Gas+ Flared Gas

21.90	g/mol	Flared gas molecular weight	Volume weighted mol. wt. of all components
2.96E+08	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
2.29E+08		q_n	$q_n = q(1\text{-}0.048(MW)^{1/2})$
15.1	m	Effective stack diameter (D)	$D = (10^{-6}q_n)^{1/2}$

Emission Rates

Pilot+ Purge Gas

NOx	CO	VOC	H_2S	SO_2	Units	
0.068	0.370				lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
			4E-04		lb H_2S/Mscf	Purchased sweet natural gas fuel, 0.25 gr H_2S/100scf
			1.1E-03		lb H_2S/hr	H_2S rate * fuel usage
				7E-03	lb S/Mscf	Sweet natural gas fuel, 5 gr S/100scf
				2E-02	lb SO_2/hr*	SO_2 rate * fuel usage
		0.00%			mol%	Assume no VOC content in purchased fuel (methane)
		12.6			ft^3/lb	Specific volume (methane)
		0.00			lb/hr	vol. Gas * mole fraction / specific volume
100%	100%	100%	100%	100%	%	Safety Factor
0.14	0.74				lb/MMBtu	Unit emission rate with Safety Factor
0.43	**2.3**				lb/hr	lb/MMBtu * MMBtu/hr
		-	**4.5E-05**	**4.5E-02**	lb/hr	98% combustion H_2S; 100% conversion to SO_2
1.9	**10.2**	**-**	**2.0E-04**	**2.0E-01**	tpy	8760 hrs/yr

Flared Gas

NOx	CO	VOC	H_2S	SO_2	Total HAPs	Units	
0.068	0.370					lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
		9.43%	0.38%		0.09%	mol%	Flare Gas
		7.5	11		4.1	ft^3/lb	Specific volume
		43,114	1,165		728	lb/hr	vol. Gas * mole fraction / specific volume
287	1563					lb/hr	lb/MMBtu * MMBtu/hr
287	**1563**	**43,114**	**1,165**	**2,148**	**728**	**lb/hr**	Uncontrolled emissions at maximum rate
2.4	**13**	**368**	**9.9**	**19**	**6.2**	**tpy**	

Controlled AGI Flare	NOx	CO	VOC	H_2S	SO_2	HAPs	Units
Pilot + Purge Gas+ Flared Gas	**287.8**	**1,564**	**861.8**	**23**	**2,148**	**15**	lb/hr
	4.3	**23.6**	**7.4**	**0.20**	**18.9**	**0.12**	tpy

Total HAPs conservatively assumed to be Hexanes+

GHG Emissions

	CO_2e Short Tons/yr		
CO_2	4,387	Eq 4-15	API Compendium
CH_4	4.5E+00	Eq 4-16	API Compendium
N_2O	9.6E-05	Eq 4-17	API Compendium
Total CO2e	**4,500**		

DCP Operating Company, LP - Linam Ranch Gas Plant

AGI Flare- Acid Gas Analysis (per 11/4/13 DCP Email)

Emission Unit: AGI Flare

Estimated Flared Gas Composition Used for Calculations

Component	MW	Flared Gas[1] Mol%	MW * wet vol %	HHV Btu/scf[2]	Btu/scf * wet vol %	Mass Fraction (wet)	Spec. Volume[2] ft^3/lb	Spec. Volume VOC ft^3/lb
Water	18.02	1.13%	0.20	0.0	0.0	0.00	21.06	
Hydrogen Sulfide	34.08	18.71%	6.38	637.02	119.2	0.15	11.136	
Carbon Dioxide	44.01	80.65%	35.50	0.0	0.0	0.84	8.623	
Nitrogen	28.01	0.01%	0.00	0.0	0.0	0.00	13.547	
Oxygen	32.00	0.00%	0.00	0.0	0.0	0.00	11.859	
Methane	16.04	0.36%	0.06	1009.7	3.6	0.00	23.65	
Ethane	30.07	0.08%	0.02	1768.7	1.4	0.00	12.62	
Propane	44.10	0.03%	0.02	2517.2	0.9	0.00	8.606	1.094
i-Butane	58.12	0.06%	0.03	3252.6	1.8	0.00	6.529	1.790
n-Butane	58.12	0.02%	0.01	3262	0.8	0.00	6.529	0.764
i-Pentane	72.15	0.01%	0.00	3999.7	0.2	0.00	5.26	0.167
n-Pentane	72.15	0.01%	0.01	4008.7	0.3	0.00	5.26	0.266
Hexane	86.18	0.05%	0.05	4756.1	2.6	0.00	4.404	1.759
		101%	42.28		130.9	1.00		5.840
NMNEHC (VOC)		0.2%				0.3%		

[1] *Based on DCP's recent 11/1/13 Linam Ranch Acid Gas Flare Gas Analysis to provide conservative estimates for sulfur dioxide and heat release estimate.*

[2] *Component HHVs and specific volumes obtained from Physical Properties of Hydrocarbons, API Research Project 44, Fig. 16-1, Rev. 1981.*

Fuel Data

Flare Pilot	500	scf/hr	Engineering judgement
	0.0005	MMscf/hr	
	1000	Btu/scf	Pipeline Gas, HHV, nominal from Linam T5 app.
	0.50	MMBtu/hr	MMscf/hr * Btu/scf
Purge Gas	16	Mscf/day	per DCP Midstream (Jennifer Corser 10/29/13 email)
	0.67	Mscf/hr	Mscf/d / 24 hr/day
	0.001	MMscf/hr	Mscf/hr / 1000
	1000	Btu/scf	Pipeline Gas, HHV, nominal from Linam T5 app.
	0.67	MMBtu/hr	MMscf/hr * Btu/scf
Assist Gas			
	134	Btu/scf	Heating value of Pilot + Purge gas + Flared gas
	500	Btu/scf	target heat content
	1000	Btu/scf	Assist gas-assumed sweet
	0.22	MMscf/hr	Assist gas volume
	219	MMBtu/hr	Assist gas heat input
Assist gas - Annual*	0.44	MMscf/yr	Estimated Maximum annual SSM flow rate. Not a requested limit; for calculation only.

Note: Flared gas annual/ ratio of assist gas: flared gas hourly usage) ex: 10.5 MMscf/yr / (1-.8054)

Flared Gas - Short Term	0.30	MMscf/hr	Maximum Effective hourly flowrate taken from 2010 - 2013 Blowdown Data for AGI Flare
	131	Btu/scf	Heating value calculated from gas compostion above.
	39	MMBtu/hr	Hourly heat rate = Heating value * Effective hourly flow rate.
Flared Gas - Annual	0.26	MMscf/yr	Estimated Maximum annual SSM flow rate. Taken from avg of 2010 - 2013 SSM blowdown data for Linam Ranch GP. Not a requested limit; for calculation only.
Total	260	MMBtu/hr	**Pilot + Purge gas + Flared gas**

Stack Parameters

1,832	˚F	Exhaust temperature	Per Linam 2-H sheet
65.6	ft/sec	Exhaust velocity	Per Linam 2-H sheet
210.0	ft	Flare height	
Pilot+ Purge Gas only			
16.04	g/mol	Pilot & Purge gas molecular weight	Mol. wt. of methane, the dominant species

DCP Operating Company, LP - Linam Ranch Gas Plant

AGI Flare- Acid Gas Analysis (per 11/4/13 DCP Email)

Emission Unit: AGI Flare

81,667 cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
65,967	q_n	$q_n = q(1\text{-}0.048(MW)^{1/2})$
0.26 m	Effective stack diameter (D)	$D = (10^{-6}q_n)^{1/2}$

Pilot + Purge Gas+ Flared Gas + Assist Gas

42.18 g/mol	Flared gas molecular weight	Volume weighted mol. wt. of all components
1.82E+07 cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
1.25E+07	q_n	$q_n = q(1\text{-}0.048(MW)^{1/2})$
3.5 m	Effective stack diameter (D)	$D = (10^{-6}q_n)^{1/2}$

Emission Rates

Pilot+ Purge Gas

NOx	CO	VOC	H_2S	SO_2	Units	
0.068	0.37				lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
			3.6E-04		lb H_2S/Mscf	Purchased sweet natural gas fuel, 0.25 gr H_2S/100scf
			4.17E-04		lb H_2S/hr	H_2S rate * fuel usage
				7.1E-03	lb S/Mscf	Sweet natural gas fuel, 5 gr S/100scf
				8.3E-03	lb SO_2/hr*	SO_2 rate * fuel usage
		0.00%			mol%	Assume no VOC content in purchased fuel (methane)
		13			ft^3/lb	Specific volume (methane)
		0.00			lb/hr	vol. Gas * mole fraction / specific volume
100%	100%	100%	100%	100%	%	Safety Factor
0.14	0.74				lb/MMBtu	Unit emission rate with Safety Factor
0.16	**0.86**				lb/hr	lb/MMBtu * MMBtu/hr
		-	**1.7E-05**	**1.7E-02**	lb/hr	98% combustion H_2S; 100% conversion to SO_2
0.69	**3.8**	-	**7.3E-05**	**7.3E-02**	tpy	8760 hrs/yr

Assist gas

NOx	CO	VOC	H_2S	SO_2	Units	
0.068	0.370				lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
			3.6E-04		lb H_2S/Mscf	Purchased sweet natural gas fuel, 0.25 gr H_2S/100scf
			7.84E-02		lb H_2S/hr	H_2S rate * fuel usage
				7.1E-03	lb S/Mscf	Purchased sweet natural gas fuel, 5 gr S/100scf
				1.6E+00	lb SO_2/hr	SO_2 rate * fuel usage
		0.00%			mol%	Assume no VOC content in purchased fuel (methane)
		12.6			ft^3/lb	Specific volume (methane)
		0.000			lb/hr	vol. Gas * mole fraction / specific volume
14.9	**81.2**				lb/hr	lb/MMBtu * MMBtu/hr
		-	**1.6E-03**	**1.6E+00**	lb/hr	98% combustion H_2S; 100% conversion to SO_2
0.015	**40.6**	-	**1.6E-06**	**1.6E-03**	tpy	

Flared Gas

NOx	CO	VOC	H_2S	SO_2	Total HAPs	Units	
0.0680	0.3700					lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
		0.18%	18.71%		0.05%	mol%	Flare Gas
		5.840	11.136		4.404	ft^3/lb	Specific volume
		93.5	5,041.4		37.3	lb/hr	vol. Gas * mole fraction / specific volume
2.67	14.53					lb/hr	lb/MMBtu * MMBtu/hr
2.7	**14.5**	**93.5**	**5,041.4**	**9,299.9**	**37.3**	**lb/hr**	Uncontrolled emissions at maximum rate
0.0011	**0.0062**	**0.040**	**2.2**	**4.1**	**0.016**	**tpy**	

Controlled AGI Flare	NOx	CO	VOC	H_2S	SO_2	HAPs	Units
Pilot + Purge Gas+ Flared Gas	**17.9**	**96.6**	**1.9**	**101**	**9,301**	**0.75**	lb/hr
	0.71	**44**	**8.0E-04**	**0.043**	**4.1**	**0.00032**	tpy

Total HAPs conservatively assumed to be Hexanes+

GHG Emissions

	CO_2e Short Tons/yr		
CO_2	0.2	Eq 4-15	API Compendium
CH_4	9.7E-05	Eq 4-16	API Compendium
N_2O	4.2E-07	Eq 4-17	API Compendium
Total CO2e	**0**		

Attachment B – Solar Wet NOx Letter

Solar Turbines
A Caterpillar Company
Powering the Future Through Sustainable, Innovative Energy Solutions

February 18, 2020
DCP SENM
Attn: John Cook

SUBJECT: Wet Nox on SENM Solar Turbines

Dear Mr. Cook:

Thank you for your questions regarding emissions controls on the South East New Mexico turbines. Currently our emissions controls offering on our 2-shaft turbines are limited to SoLoNOx technology. In the past we have offered Wet-Nox emissions controls on our generator set packages. This technology is no longer offered as our SoLoNOx technology offers lower emissions control with a lower operational cost to our customers. Attached below are the current SoLoNOx emissions limits as well as our historical best available Wet-Nox limits.

Regards,
Javier Marquez
Western Region Aftermarket Account Manager
(432)-559-7430
Marquez_Javier@Solarturbines.com

SoLoNOx-Natural Gas Fuel (ppmvd @15%O2)

Combustor	Pollutant	Taurus 70	Taurus 60	Centaur 50	Centaur 40
		10802S 10302S	7802S	6102S	4702S
SoLoNOx	ISO Nox ppm	15	15	25	25
	CO ppm	25	25	25	50
	UHC Nox ppm	25	25	25	25

Water Injection - Natural Gas Fuel (ppmvd @15% O_2)

Combustor	Pollutant	*Taurus* 70 [m]	*Taurus* 60	*Centaur* 50	*Centaur* 40	*Saturn* 20
		10801 10301	7901	6201	4700	1601
Conventional [a] with Water Injection	ISO NOx ppm (mg/Nm^3)	60 (125)	42 (88)	42 (88)	42 (88)	42 (88)
	CO ppm (mg/Nm^3)	50 (64)	50 (64)	50 (64)	50 (64)	50 (64)
		200 (254)	200 (254)	200 (254)	200 (254)	200 (254)
	UHC ppm (mg/Nm^3)	25 (18)	25 (18)	25 (18)	50 (36)	25 (18)

Attachment C – Priority Power Discussion

Hong, Hyung S

From: Cook, John W
Sent: Thursday, February 20, 2020 2:03 PM
To: Tourangeau, Paul R; Hong, Hyung S
Subject: FW: Xcel - Linam Ranch Gas Plant

From: LAnglois, Kenneth J
Sent: Thursday, February 20, 2020 1:54 PM
To: Cook, John W <JWCook@dcpmidstream.com>
Cc: Admire, John D <JDAdmire@dcpmidstream.com>
Subject: Fwd: Xcel - Linam Ranch Gas Plant

FYI

Kenneth
936-446-8366
Get Outlook for iOS

From: Brian Craig <bcraig@prioritypower.net>
Sent: Thursday, February 20, 2020 11:45 AM
To: LAnglois, Kenneth J
Cc: Smith, Rodney P; Roger Kienast; Kevin Yung
Subject: Xcel - Linam Ranch Gas Plant

Kenneth,
The second part to your question related to the 100 MW is a much more involved issue. Serving a load this size would require a major study on the part of XCEL to see how this load could be served. Any transmission project (regardless of size) must go through XCEL's transmission planning group to see what it would take to serve the load. In this case, the amount of load is so large, that the capacity of the lines now also come into play. Normally our rule of thumb for a 10 MW load would be 18 months to 24 months from the date the customer initiates studies. Increasing the load 10 fold will definitely stretch this out. I would like to tell you it could be done in 3 yrs but that really is going to depend on the generation capacity and whether or not the conductors need to be resized to handle the new load.

Best way to find out is to submit a request to XCEL and let them study it. The request will need a detailed load list showing all the motors, et all that add up to the 100 MW of load. Let me know if this is what you want to do and if so I will reach out to XCEL to get more information.

Thanks,

Brian

Brian Craig | Sr. Director, Business Development

Priority Power Management LLC | *Your Trusted Energy Advisor*
690 E. Lamar Blvd., Suite 500 | Arlington, TX 76011
T 817.453.1411 | F 817.549.0164 | C 817.320.7269
bcraig@prioritypower.net | www.prioritypower.net

From: Brian Craig
Sent: Thursday, February 20, 2020 11:12 AM
To: L'Anglois, Kenneth J <KJLAnglois@dcpmidstream.com>
Cc: Smith, Rodney P <RPSmith@dcpmidstream.com>
Subject: Xcel - Linam Ranch Gas Plant

Kenneth,
See Roger's note below on the capacity of the line being 13.9 MVA. This would indicate you have room to add another 2.500 hp load without issues. However, this only addresses your feeder from the plant to the substation (the one PPM built for you). Still need to check with XCEL on their system and capabilities. I will reach out to them and see what they say.

Brian

Brian Craig | Sr. Director, Business Development

Priority Power Management LLC | *Your Trusted Energy Advisor*
690 E. Lamar Blvd., Suite 500 | Arlington, TX 76011
T 817.453.1411 | F 817.549.0164 | C 817.320.7269
bcraig@prioritypower.net | www.prioritypower.net

From: Roger Kienast <rkienast@prioritypower.net>
Sent: Wednesday, February 19, 2020 12:05 PM
To: Brian Craig <bcraig@prioritypower.net>; Kevin Yung <kyung@prioritypower.net>
Subject: RE: Xcel - Linam Ranch Gas Plant

Brian, we built the DCP Linam one-span feeder with 477 ACSR for this 7.2/12.47kV distribution line. That wire size can handle up to 646amps, which is about 13.9 MVA. However, it should not be loaded up to that amount, as DCP will experience voltage problems before that limit.

Adding more load truly depends on Xcel Energy's approval and ability to serve it. Attached is the PSA from James Delaney in May 2018. Unfortunately, it doesn't list how much they are approved for at the PME. Perhaps you have records of that and/or can get it from Xcel?

Thanks.

Roger Kienast, P.E. | Sr. Project Engineer, Lead

Priority Power Management LLC | *Your Trusted Energy Advisor*
Office: 432.620.9100 Fax: 432.620.9145
Direct: 432.400.2460 Cell: 605.376.5166
5012 Portico Way, Midland, TX 79707
rkienast@prioritypower.net | www.prioritypower.net

From: Brian Craig <bcraig@prioritypower.net>
Sent: Wednesday, February 19, 2020 11:27 AM
To: Kevin Yung <kyung@prioritypower.net>; Roger Kienast <rkienast@prioritypower.net>
Subject: Xcel - Linam Ranch Gas Plant

Can you help me with Kenneth's question?

Current load is as follows:

$ 2,262,538.84 Total Cost of **16 Bills**

Account Code	Billing Period - 1	Bill Begin Date	Bill End Date	Days
5483641736	Dec 2019	12/17/2019	01/20/2020	34
5483641736	Nov 2019	11/14/2019	12/17/2019	33
5483641736	Oct 2019	10/16/2019	11/14/2019	29
5483641736	Sep 2019	09/17/2019	10/16/2019	29
5483641736	Aug 2019	08/16/2019	09/17/2019	32
5483641736	Jul 2019	07/18/2019	08/16/2019	29
5483641736	Jun 2019	06/18/2019	07/18/2019	30
5483641736	May 2019	05/17/2019	06/18/2019	32
5483641736	Apr 2019	04/18/2019	05/17/2019	29
5483641736	Mar 2019	03/20/2019	04/18/2019	29
5483641736	Feb 2019	02/19/2019	03/20/2019	29
5483641736	Jan 2019	01/18/2019	02/19/2019	32
5483641736	Dec 2018	12/17/2018	01/18/2019	32
5483641736	Nov 2018	11/14/2018	12/17/2018	33
5483641736	Oct 2018	10/15/2018	11/14/2018	30
5483641736	Sep 2018	09/16/2018	10/15/2018	29

What size line was put in for the Linam Ranch Feeder from the Monument sub (12.5kV or 25kV? Expect there is plenty of capacity regardless for the additional 2,500 hp unit. I am not aware of a study done by XCEL to address the adding of this unit.

Brian

From: LAnglois, Kenneth J <KJLAnglois@dcpmidstream.com>
Sent: Wednesday, February 19, 2020 10:36 AM
To: Brian Craig <bcraig@prioritypower.net>
Cc: Smith, Rodney P <RPSmith@dcpmidstream.com>; Cook, John W <JWCook@dcpmidstream.com>
Subject: Xcel - Linam Ranch Gas Plant

Brian,

Do you have access to the "study" that was done to determine whether or not we could add the 2500 HP 4160V motor at Linam Ranch Gas Plant using the existing dedicated line from the Monument sub-station?

Was that done by Xcel or by your team?

We are getting asked by the NMED what the maximum additional delivery is to Linam on that new dedicated line. The additional 2500 HP motor at the plant could still happen – that project is "on hold" at the moment, but could be re-activated.

I would expect that we would need to pay for a completely new substation (100 MW?) located at the plant to convert all of our existing turbines/engines from fuel-powered to electric.

Best regards,

Kenneth
936-446-8366

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Attachment D – SoLoNOx and SCR estimate

Hong, Hyung S

From: Javier Marquez <Marquez_Javier@solarturbines.com>
Sent: Tuesday, October 1, 2019 3:52 PM
To: Hong, Hyung S
Cc: Cook, John W
Subject: RE: Sam Hong from DCP Midstream contact

Hi Sam,

We have not done many SCR's through our company but the quotes we do have ranged from 850K-1,200,00 depending on what the starting emissions were to what the required target was. From what I can tell it does not looked like we have executed any of the SCR projects. The few of our customers that do have SCR's went directly to the SCR vendors.

Regards,

Javier Marquez
Account Manager, Western Region
Solar Turbines Incorporated
Email: Marquez_Javier@solarturbines.com
Mobile: (432)-559-7430

Caterpillar: Confidential Green

From: Hong, Hyung S <HSHong@dcpmidstream.com>
Sent: Tuesday, October 1, 2019 1:31 PM
To: Javier Marquez <Marquez_Javier@solarturbines.com>
Cc: Cook, John W <JWCook@dcpmidstream.com>
Subject: Sam Hong from DCP Midstream contact

Javier,

Thank you for speaking with me over the phone.

Please see below contact information!

Sam Hong
DCP Midstream
10 Desta Dr. Ste 500W
Midland, TX 79705
432.620.5463 (O) | 432.215.8514 (M)

From: Cook, John W
Sent: Tuesday, October 1, 2019 3:56 AM

	Linam Ranch				
	T70 Inlet	**T60 Inlet**	**T70 Residue**	**T4700**	**Propane**
Best Available in NM	15PPM	Not Subject to Four Factor	15PPM	25PPM	25PPM
OH Estimate	$1,750,000.00		$1,750,000.00	$400,000.00	$400,000.00
NOx Conversion Fee to Best Available	$105,500.00		$105,500.00	$117,606.00	$117,606.00
Required Package Upgrades	$45,000.00		$45,000.00	$984,667.00	$984,667.00
Total	$1,900,500.00		$1,900,500.00	$1,502,273.00	$1,502,273.00
Site Total	**$6,805,546.00**				

Caterpillar: Confidential Green

Attachment E – Engine SCR vendor discussion

Hong, Hyung S

From: Justin Zimbelman <jzimbelman@catalyticcombustion.com>
Sent: Wednesday, October 9, 2019 10:42 AM
To: Hong, Hyung S
Subject: RE: Linam Clark engines back pressure limit

Hey Sam,

Below is the rough numbers I have come up with, making a lot of assumptions…

Per engine~
Reactor Housing: $200,000
Reactor Housing Install: $75,000
Annual Run time avg cost (urea consumption, maintence): $350,000

Negative side effects:
Particulate Matter "PM" slip will be quite substantial as these are really dirty engines were trying to control
Catalyst Maintenance: because of the level of control and the nature of these engines the catalyst will mask off fairly quickly and require lots of maintenance and service.

Justin Zimbelman
Market Development Manager
Gas Compression Products
Mobile: 715-933-2290

Corporate: 715-568-2882
jzimbelman@catalyticcombustion.com
www.catalyticcombustion.com

Catalytic Combustion Corporation
Cheyenne, WY

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From: Hong, Hyung S <HSHong@dcpmidstream.com>
Sent: Wednesday, October 9, 2019 9:17 AM
To: Justin Zimbelman <jzimbelman@catalyticcombustion.com>
Subject: FW: Linam Clark engines back pressure limit

Justin,

Please see below response from our asset engineer!

Sam Hong
DCP Midstream

10 Desta Dr. Ste 500W
Midland, TX 79705
432.620.5463 (O) | 432.215.8514 (M)

From: Tabery, Ronald S
Sent: Wednesday, October 9, 2019 9:00 AM
To: Hong, Hyung S <HSHong@dcpmidstream.com>; Lynch, Wade J <WJLynch@dcpmidstream.com>
Cc: Cook, John W <JWCook@dcpmidstream.com>
Subject: RE: Linam Clark engines back pressure limit

Sam,

All Clarks have a direct-to-atmosphere exhaust stack (unrestricted flow).
Without measuring to confirm, my *conjecture* is that backpressure is single digit.
OF course any increase in backpressure is concomitant with a decrease in power (unwelcome); for this reason, think big…

Ronald S. Tabery, P.E.
Principal Engineer
Linam/Hobb NM
575-391-5740
432-813-3073 Mobile

From: Hong, Hyung S
Sent: Tuesday, October 8, 2019 3:51 PM
To: Tabery, Ronald S <RSTabery@dcpmidstream.com>; Lynch, Wade J <WJLynch@dcpmidstream.com>
Cc: Cook, John W <JWCook@dcpmidstream.com>
Subject: Linam Clark engines back pressure limit

Ron/Wade,

SCR vendor is wanting to know back pressure limitation on the exhaust to provide quote for correct size SCR system.

Example: a Caterpillar 3616le engine has an engine exhaust backpressure limitation of 20 inches of water. Knowing that we have to size our equipment large enough so that it doesn't restrict the exhaust flow rates and de-rate or harm the engines mechanical performance

Is this information available anywhere? I've checked through all of the old air permit applications and could not find anything other than engine parameters and emission guarantees.

I know it's a long shot but maybe on the engine operating manual or anything we can dig into?

Sam Hong
DCP Midstream
10 Desta Dr. Ste 500W
Midland, TX 79705
432.620.5463 (O) | 432.215.8514 (M)



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Attachment F – EU 10 & 11 Stack Test Report

ASTM 6522 Annual

Performance Test Report

Test Date: 12/28/16

Location:

Linam Ranch Gas Plant

Unit:

EU11

County

Lea

State

New Mexico

Source:

Clark HBA-6

Serial #: 36303

Prepared on behalf of:

DCP Midstream LP

Prepared by:

Great Plains Analytical Services

303 West 3rd Street

Elk City, OK 73644

(580) 225-0403

GAS

1.0 Key Personnel

Great Plains Analytical Services:	Tyler Burns
DCP Midstream	Anthony Garcia

2.0 Sampling System

The sampling system used consisted of a Stainless steel probe, Non-porous teflon Line, coiled stainless cooler to drop out moisture from line and an Electrochemical Analyzer. Analyzers are housed in the air conditioned cab of the mobile laboratory. The sample system contains a seperate path to deliver EPA protocol gas to the port in order to allow testing of the entire system. A schematic Diagram can also be found in section 4 of this report.

3.0 Methods

EPA Method 1 or 1A

The purpose of the method is to provide guidance for the selection of sampling ports and traverse points at which sampling for air pollutants will be performed pursuant to regulations set forth in this part. This method is designed to aid in the representative measurement of pollutant emissions. This method is used for stacks with a diameter larger than 12 inches. Should the stack not meet that requirment, method 1A will be used. The applicability and principle of Method 1A are identical to Method 1 in stacks.

EPA Method 2 or 2C

This method is applicable for the determination of the average velocity and the volumetric flow rate of a gas stream.

ASTM D6522

This is the standard test method for determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen concentrations in emissions from natural gas fired reciprocating engines, using portable analyzers

5.0 Summary

A Clark HBA-6 located at Linam Ranch Gas Plant and operated by DCP Midstream LP was tested for emissions of Carbon Monoxide (CO), Oxides of Nitrogen (NOx). The test was conducted by Tyler Burns with Great Plains Analytical Services, Inc. All quality assurance and quality control tests were within acceptable tolerances. This test was conducted using (3) 1 hour test runs.

Engine Tag



Pollutant		Test Results (Average)	Federal Permit	State Permit
CO	ppmvd	191.68	-	-
NOx	ppmvd	222.57	-	-
O2	%	0.15	-	-
CO	ppmvd @ 15% O2	191.89	-	-
NOx	ppmvd @ 15% O3	222.81	-	-
CO	g/hp-hr	0.21	-	-
NOx	g/hp-hr	0.41	-	-
CO	lb/hr	0.57	-	24
NOx	lb/hr	1.09	-	47.5
CO	tpy	2.51	-	283
NOx	tpy	4.78	-	566

6.0 Test Results and Engine Data

Run Number			Run 1	Run 2	Run 3	Run Length
Test Date & Start Time	12/28/16		8:48 AM	9:55 AM	11:02 AM	1 Hour
Engine/Compressor Specs						
Make			Clark			
Model			HBA-6		Stack Diameter in	18.00
Serial number			36303		Catalyst	Yes
mfg. rated hp			1267			
mfg. rated rpm			300			
Engine/Compressor Operation			**Run 1**	**Run 2**	**Run 3**	**Average**
Test Horsepower			1207	1211	1211	1209
Test RPM			299	298	299	299
Percent Load %			95.23%	95.57%	95.54%	95.45%
Intake Manifold Temperature (F)			103.0	103.0	103.0	103.0
Ambient Conditions				Elevation ft.=	3741	
Ambient Temperature Dry (F)			54	60	67	60
Barometric Pressure ("hg)			30.17	30.17	30.17	30.17
Exhaust Flow Data						
Q Stack (dscfh)			41145	41100	41019	41088
Q Stack (dscmh)			1165	1164	1162	1163
Fuel Flow Data (Irrelevant when using Method 2. Calculated for internal use from Exhaust flow.						
Fuel Consumption (Btu/hp-hr)			1100	1100	1100	1100
Fuel Flow (dscf-hr)			1285	1289	1289	1288
Fuel (Btu/scf)			1033	1033	1033	1033
O2 F factor			8710	8710	8710	8710
Exhaust Gas Concentrations			**Run 1**	**Run 2**	**Run 3**	**Average**
CO (ppmv)			185.99	192.30	196.76	191.68
NOx (ppmv)			199.23	229.82	238.66	222.57
Oxygen						
O2%			15.03%	15.00%	14.99%	15.01%
Exhaust Gas Concentrations						
CO (ppmv) @ 15% O2			186.87	192.32	196.44	191.89
NOx (ppmv) @ 15% O2			200.18	229.84	238.27	222.81
Mass Emissions Rates		**State Limit**				
NOx (lbs/hr)		47.5	0.98	1.13	1.17	1.09
NOx (tpy)		566	4.29	4.94	5.12	4.78
NOx (g/hp-hr)			0.37	0.42	0.44	0.41
CO (lbs/hr)		24	0.56	0.57	0.59	0.57
CO (tpy)		283	2.44	2.52	2.57	2.51
CO (g/hp-hr)			0.21	0.22	0.22	0.21

7.0 Volumetric Flow Rate

Pitot Coefficient Cp(std)	0.99			Velocity Constant K(p)=		85.49
Stack diameter	18	inches	1.5	Feet or	1.77	Sq Feet (A)
			Run 1	Run 2	Run 3	Average
Relative Humidit (RH)		%	26.00	18.00	17.00	20.33
Barometric Pressure (Pbar)		"Hg	30.17	30.17	30.17	30.17
Ambient Temperature		F	54.00	60.00	67.00	60.33
Moisture in Ambient Air (Ba)		Mol Fraction	0.003624	0.003116	0.003762	0.003501
Free Water (w)		%	2.429451	2.429451	2.429451	2.429451
Moisture free water in fuel (Bf)		Mol Fraction	0.000000	0.000000	0.000000	0.000000
Moisture from Hydrogen in Fuel (Bh)		Mol Fraction	0.050314	0.050549	0.050634	0.050499
Moisture in Stack Gas (Bws)		%	0.05	0.05	0.05	0.05
CO2%d		%	0.03	0.03	0.03	0.03
H2O%d		%	0.05	0.05	0.05	0.05
O2%d		%	0.15	0.15	0.15	0.15
CO%d		%	0.02	0.02	0.02	0.02
N2%d		%	0.80	0.80	0.80	0.80
Molecular Weight Stack Gas dry basis (Md)		g/g mole	29.15	29.15	29.15	29.15
Molecular Weight Stack Gas wet basis (Ms)		g/g mole	28.55	28.55	28.54	28.55
Δp (Velocity Head of Stack Gas)		"H2O	0.02	0.02	0.02	0.02
Stack Temperature (Ts)		Deg F	675.00	678.00	681.00	678.00
Stack Temperature(Ts(abs))		Deg R	1135.00	1138.00	1141.00	1138.00
Atmospheric Pressure at Location (Pbar)		"Hg	30.17	30.17	30.17	30.17
Absolute Stack Pressure (Ps)		"Hg	30.17	30.17	30.17	30.17
Stack Gas Velocity (Vs)		Feet/Second	14.57	14.59	14.61	14.59
Stack Gas Dry Volumetric Flow Rate (Qsd)		dscf/hr	41145.34	41099.75	41019.47	41088.11
Δp (Velocity Head of Stack Gas)		"Hg	0.00	0.00	0.00	0.00
Stack Flow Rate Q (cfs)		$Feet^3$/Second	25.75	25.79	25.82	25.79
Stack Gas Wet Volmetric Flow Rate		scf/hr	43491.17	43430.45	43379.13	43433.51

Annual

Performance Test Report

Test Date: 3/9/16

Location:

Linam Gas Plant

Unit:

Unit #3

County

Lea

State

New Mexico

Source:

HBA-6

Serial #: 38288

Prepared on behalf of:

DCP Midstream

Prepared by:

Great Plains Analytical Services

303 West 3rd Street

Elk City, OK 73644

(580) 225-0403

1.0 Key Personnel

Great Plains Analytical Services: Travis Hartley

2.0 Sampling System

The sampling system used consisted of a Stainless steel probe, Non-porous teflon Line, coiled stainless cooler to drop out moisture from line and Testo 350 analyzer.

3.0 Methods

EPA Method 1

The purpose of the method is to provide guidance for the selection of sampling ports and traverse points at which sampling for air pollutants will be performed pursuant to regulations set forth in this part. This method is designed to aid in the represnetative measurement of pollutant emissions. This method is used for stacks with a diameter larger than 12 inches. Should the stack not meet that requirment, method 1A will be used. The applicability and principle of Method 1A are identical to Method 1 in stacks.

EPA Method 2 & 2C

This method is applicable for the determination of the average velocity and the volumetric flow rate of a gas stream.

EPA Method 7E

This method is for measuring nitrogen oxides (Nox) in stationary sources using a continuous instrumental analyzer. Quality assurance and control requiremnents are also included in this method

EPA Method 10

This method is for measuring carbon monoxide in stationary sources using a continuous instrumental analyzer.

6.0 Test Results and Engine Data

Run Number			Run 1	Run 2	Run 3	Average
Test Date & Start Time	03/09/16		3:25 PM	4:32 PM	5:39 PM	
Engine/Compressor Specs						
Make			Clark		Elevation ft.	3,728
Model			HBA-6			
Serial number			38288		Atmospheric	
mfg. rated hp			1267		Pressure. psi	12.829
mfg. rated rpm			300		Stack Diameter i	18.00
					Catalyst	No
Engine/Compressor Operation						
Test Horsepower			1222	1215	1203	1213
Test RPM			302	304	303	303
Percent Load %			96.44%	95.91%	94.97%	95.77%
Intake Manifold Temperature (F)			123	128	124	125
Fuel Flow (scfd)			241297	239975	237633	239635
Q Stack (dscfh)			285400	282479	281066	282982
Ambient Conditions						
Ambient Temperature Dry (F)			65.0	65.0	60.0	63.3
Barometric Pressure (hg)			29.90	29.90	29.90	29.90
Exhaust Flow Data						
Fuel Consumption (Btu/hp-hr)			8500.00	8500.00	8500.00	8500.00
Fuel Flow (dscf-hr)			10054.06	9998.97	9901.38	9984.81
Fuel (Btu/scf)			1033.0	1033.0	1033.0	1033.0
O2 F factor			8710	8710	8710	8710
Exhaust Gas Concentrations	**Limits**					
CO (ppmv)			340.89	405.09	371.69	372.56
NOx (ppmv)			420.24	435.63	400.96	418.94
NO (ppmv)			58.18	61.34	55.66	58.39
NO2 (ppmv)			478.42	496.97	456.62	477.33
Oxygen						
O2%			14.28%	14.24%	14.28%	14.26%
Mass Emissions Rates	**Limits**					
NO (lbs/hr)			1.983	2.070	1.869	1.97
NO2 (lbs/hr)			16.311	16.770	15.331	16.14
NOx (lbs/hr)	47.50		18.295	18.840	17.200	18.11
NO (tpy)			8.688	9.066	8.186	8.65
NO2 (tpy)			71.442	73.453	67.152	70.68
NOx (tpy)			80.130	82.519	75.337	79.33
NO (g/hp-hr)			0.736	0.773	0.705	0.74
NO2 (g/hp-hr)			6.055	6.260	5.779	6.03
NOx (g/hp-hr)			6.792	7.033	6.484	6.77
CO (lbs/hr)	24.00		7.075	8.322	7.598	7.665
CO (tpy)			30.990	36.450	33.277	33.573
CO (g/hp-hr)			2.627	3.106	2.864	2.865

Steven R. Torpey, PE
Sr Env Air Permitting Engineer

PROVIDING ENERGY. IMPROVING LIVES.

PHILLIPS 66
HQ-08N-N806-03
2331 CityWest Boulevard
Houston, TX 77042-2862
O: 832-765-3444
E: Steve.Torpey@P66.com

August 28, 2023

New Mexico Environment Department
Air Quality Bureau
Permit Programs Manager
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

Re: Regional Haze
Linam Ranch Gas Plant
NMED ID 589
DCP Operating Company, LP

Dear Michael Baca,

Phillips 66 Company is submitting this document on behalf of DCP Operating Company LP (DCP), as it is an indirect subsidiary.

On July 12, 2023, representatives of DCP met with New Mexico Environmental Department (NMED) to discuss DCP plants that are of interest for the purposes of Regional Haze Planning. While the Artesia Gas Plant and Eunice Gas Plant issues were addressed during the meeting, there were outstanding questions for the Linam Ranch Gas Plant. This letter addresses those outstanding questions and follows the numbering of the July 12, 2023 NMED agenda.

Question 4.b. What plans, if any, does DCP have for retiring or replacing any of the engines or combustion turbines (CTs) at the Linam Ranch facility?

> DCP does not have any plans to retire or replace any of the combustion turbines at Linam Ranch Gas Plant. DCP has been working with turbine manufacture (Solar Turbines) to install upgrades/controls to the existing turbines to be compliant with §20.2.50 NMAC.

Turbines 28, 29, and 30 have been upgraded to be compliant with §20.2.50 NMAC.

Turbine Unit No.	NOx (ppmvd @15% O2)	Note
28	15	Solar upgrade complete
29	15	Solar upgrade complete
30	25	Solar upgrade complete
31	25	Solar upgrade expected to be complete by end of 2023
32B	<50	Future Solar upgrade to be completed by 20.2.50 NMAC timeline.

Turbine 31 is expected to be compliant with §20.2.50 NMAC by the end of 2023. Turbine 32B does not have a schedule, at this time, but will be compliant with §20.2.50 NMAC.

The six Clark engines (Unit Numbers 6-11) will either be replaced with different technology or retrofitted with appropriate equipment for compliance with §20.2.50 NMAC. DCP will ensure Units 6-11, or their replacements, will be compliant with §20.2.50 NMAC emission limitations and timelines.

Question 4.c. How does DCP plan to comply with the ozone precursor rule with respect to the applicable units at the Linam Ranch facility?

This has been addressed in the answer to Question 4.b.

Question 4.d. Is projected utilization of the units subject to Regional Haze expected to be appreciably different than historical utilization?

The utilization of the turbines and engines at Linam Ranch are not being modified due to the Regional Haze rule. There is ongoing drilling in the area that could have impacts on the utilization of Linam Ranch Gas Plant; however, the baseline actual emissions should be used for the projected 2028 modeling.

*Question 4.e. I*s DCP's cost-of-capital notably different that the current prime rate of ~8%?

With the current volatility of the current prime rate, the ~8% is a good an estimate as can be determined.

Question 4.f. Does DCP plan to provide updated cost evaluations for any of the pollution control options it evaluated in its submitted FFAs? If so, when should NMED expect to receive that information?

In 2021, Dresser-Rand provided an indicative pricing for necessary system retrofits on the Clark engines for the, at the time, proposed 20.2.50 NMAC regulations. Attached, is shown that the total indicative pricing is $3.05MM in 2021. Additionally, attached is an email in 2023 that indicates with inflation and supply chain issues that 20% should be added, resulting in $3.66MM per Clark engine as a total indicative price.

Question 5.a. Does DCP anticipate continued availability of maintenance parts for its engines and CTs (especially older engines) for 10 to 20 more years?

At this point, there is no indication of a shortage of maintenance parts for the engines and CTs. Suppliers work on a competitive market and as long as there is demand there is an expectation of supply.

Question 5.b. Estimates of maintenance costs for engines and CTs?

Maintenance to engines and CTs is completed by competitive bid process. This also is affected by the supply and demand model and can fluctuate.

Question 6. Does DCP plan to provide a cost evaluation for the replacement of its existing engines and CTs with new, like-kind engines or CTs? If so, when should NMED expect to receive that information?

A cost evaluation for the replacement of the existing engines and CTs with new, like-kind equipment is not anticipated for this planning period.

Question 7.a. Does DCP plan to provide a cost evaluation for the replacement of any of its existing engines or CTs with electric motor equivalents? If so, when should NMED expect to receive that information?

Yes, the information is provided in response to Question 7.b.

Question 7.b. Please provide documentation

Here is some background information to discuss electrical infrastructure:

- The five gas-fueled turbines at Linam Ranch represent about 40,000 HP, which would be approximately 30 MW if converted to electric.
- The Clark compression engines represents another 5 MW of combined if converted to electric.
- Note: 1 HP = 745 Watts + power factor
- Linam Ranch Gas Plant currently has four large electric motors for acid-gas injection (about 5 MW total), which includes two compressors for vapor recovery.

Linam Ranch History:

- In 2018, a “one-span” was created for the plant to
  - Providing a single, isolated source of power from the sub-station 9 miles to the south.
  - Providing higher electrical reliability than the multiple, unreliable power source which had multiple customer feeds that existed prior to 2018.
  - The project had no change in total electrical capacity but reduced flaring events due to “power blips”.
  - At a cost of $1.8MM (2018) to improve electrical reliability.

The following are future costs and impacts related to electrifying the existing gas-fueled compression at Linam Ranch Gas Plant:

- Utility – Bringing an additional 35 MW of power to the site will cost $28MM.
  - Cost: $2MM/mile for transmission-level power
  - Cost: $10MM for the substation
  - Schedule: Up to 5 years for approvals from the state of NM to begin construction
  - Schedule: Up to 3 years of supply chain delays for the electrical equipment (transformers and switchgear)
- New electric compression equipment
  - Electric compression will cost about $2,000/HP when labor and on-site electrical infrastructure downstream of the sub-station is included.
  - Total Cost is $90MM
    - Turbines: 40,000 HP x $2,000
    - Engines (2SLB): 5,000 HP x $2,000
  - Schedule: About 4 to 6 years to execute after approvals
  - Rights of Way: Existing space owned by Phillips 66 is insufficient to accommodate all the new electrical buildings and substation
    - No cost estimate has been determined for additional right of way, at this time, but will need to be added.
- Total Capital Costs of Utility + New Compression: $118MM estimated
- Operational Costs ($/year)
  - Future Electricity costs to operate the same compression: $21.46MM at $70/MWh

This addresses all the outstanding questions from the July 12, 2023 meeting that were noted.

If you have any questions or need any clarification regarding this response, please feel free to contact me at steve.torpey@p66.com or 832-765-3444.

Sincerely,



Steven R. Torpey, PE (TX)
Sr. Env Air Permitting Engineer

Torpey, Steve

From: Foerg, Wolfgang M
Sent: Friday, July 21, 2023 1:27 PM
To: Cook, John W
Cc: Hoenie, Lance R
Subject: FW: DCP Midstream NM Emissions / Gas Engine Discussion
Attachments: image001.png; DCP New Mexico TLA-HBA 6 indicative summary 6-July v2.pdf

John,
See response form Siemens on the Clarks.

The technology is still the same, but they suggested adding 20% to the attached proposal to update pricing for inflation.

That will make the cost for each Clark $3.050 MM x 120% = $3.66 MM

Best Regards,

Wolfgang Foerg, P.E.

Supervisor Reliability Engineering

6900 E Layton Ave, Suite 900, Denver, CO 80237
Cell: 303-565-0475

phillips66.com

From: Davies, Kevin <kevin.davies@siemens-energy.com>
Sent: Friday, July 21, 2023 11:57 AM
To: Foerg, Wolfgang M <Wolfgang.M.Foerg@p66.com>; Foerg, Wolfgang M <WMFoerg@dcpmidstream.com>; Wiebe, Jeremy <jeremy.wiebe@siemens-energy.com>
Cc: Wesley, Lucas <lucas.wesley@siemens-energy.com>; Hoenie, Lance R <Lance.R.Hoenie@p66.com>
Subject: [EXTERNAL]DCP Midstream NM Emissions / Gas Engine Discussion

This Message Is From an External Sender
This message came from outside your organization.
Report Suspicious

Wolfgang,
Good morning,
I did a quick look at both your email and our files, and the budget Steve had set for you.
In all cases, the technology proposed is the same as was provided previously.
We'll still need to apply the same technology, which is probably good as it set's the table for meeting future emissions.
Unfortunately, as I'm sure you are aware, prices on almost everything has skyrocketed over the last 2.5 years.
Therefore, for planning purposes, I'd add another 20%, to the number's provided earlier.

If you wish to proceed beyond high level budget numbers everything Steve stated still applies, we'd need to make trip to location and gain some further detail.
Please let us know if you have any additional questions or require further support.

With best regards,
Kevin Davies

Siemens Energy, Inc.
4700 McMurry Drive
Fort Collins 80525, USA
Mobile: +1 (970) 227-9747
mailto:kevin.davies@siemens-energy.com

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6-July-2021

DCP Midstream New Mexico Proposed Rule NOx, CO, VOC Reduction Estimations

Dresser-Rand Company (hereinafter, "Dresser-Rand") appreciates the opportunity to present this *indicative pricing* for necessary system retrofits on Clark HBA-6 and TLA-6 engines to achieve targeted reduced emissions levels with 20% operating margin per the proposed New Mexico pending regulations.

The scope supports 0.5 gm NOx/bhp-hr., over a load range 80-100%, Full Speed, with +/-20% NOx operating margin.

Pricing is inclusive of on and off engine modifications required. Also listed are pricing for optional items for consideration. Assumptions identified at this time are noted.

For each "Category" item in the following table, pricing given is inclusive of estimated time and cost for Project Management, Engineering, Drafting, Procurement, Hardware, Installation Supervision, Subcontractors, Field Services Commissioning, and Expenses.

Pricing is provided for a single unit type for DCP investigative analysis of regulatory compliance options. It does not reflect potential discounts which may be offered to DCP if Siemens-Energy is awarded multiple engines to retrofit in one project or up-front commitment to multiple projects.

Pricing reflects current market price conditions. It does not reflect potential year-over-year pricing increases on materials, labor, subcontractors, etc. if work is targeted to be completed in the years 2025 and following.

No actual site visits were conducted to identify or validate specific station or engine needs to verify successful scope, price and execution of such a project.

In no way is this letter to be considered an offer for services nor binding in any manner. No purchase order nor contract may be executed against this letter.

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6-July-2021

Engine Unit Type = Clark TLA6 or HBA6

CATEGORY	PURPOSE & DESCRIPTION	PRICE (in $K)
NOx Emissions Reduction - Enhanced Combustion	**New Turbocharger x1**: Leaner AFR mixture, improved scavenging, reduced combustion temperature: ABB TPL-69. On engine mounted. Includes: Stand, wastegate, intake/exhaust piping, expansion joints, insulation. **Turbo L.O. Sump system**: To support additional requirements of off engine mounted turbocharger(s). Includes: LO pump, cooling and heating systems, reservoirs, platform, piping, end devices. **Aftercoolers x1:** New or updated aftercooler bundles to handle increased heat rejection of new turbocharger(s). Includes: Housing, cores, and piping. **EPCi - PCC fuel injectors**: Precision control of PCC fueling; eliminate miss-fires as source of NOx formation and engine imbalance. **HPFi - High Pressure Fuel Injection:** Improve A/F homogeneous mixture in cylinder to reduce A/F 'hot spots' and NOx formation; improve complete burn of in-cylinder A/F mixture. **iBALANCE:** Real-time Peak-Firing-Pressure monitoring, closed loop control to continuously auto-balance engine, reducing NOx formation due to imbalance; component protection; reliability in lean operation.	**$2,150**
Off Engine Modifications	**Air Intake Filters x1:** Required to accommodate increase intake air flow of new turbocharger(s).	**$50**
CO & VOC Emissions Reduction - Exhaust Aftertreatment	**Oxidation Catalyst:** Required treatment of exhaust gas to maintain or reduce CO and VOCs emissions in leaner operation. Piping included.	**$130**
Optional Items/Systems	**Silencer:** Hospital grade exhaust silencer if old silencers create too much back pressure/worn out. Base mount with tailpipe.	**$88**
	Jet Assist Air Study: Study to determine requirements for starting & sustaining turbocharger	**$22**
	iFLOW g3: Compressor health pressure, temperature, vibration monitoring.	**$160**
	O/H Parts - Severe Case: Parts new pistons, rings and cylinder liners. **DCI:** Would be part of the FS Labor to replace existing or with new parts.	**$450**
	TOTAL INDICATIVE PRICING:	**$3,050**

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6-July-2021

Assumptions

Cooling System	Existing fin fan systems for main/AUX can handle increased heat rejection loads
Jet Assist System	Present system can support all engine starting scenarios and turbocharger start, as well as sustaining turbochargers during low (50-65%) load operations.
Natural Gas	Pipeline quality natural gas
Electric Power	DCP supplies necessary power for new controls subpanel
Intake Filters	Stand, mounting pad, piping is re-usable
Pre-Combustion Chambers	Engines have existing system and is working. One (1) PCC per head
Catalyst/Silencer	Existing pad for silencer stand can be re-used for base-mount combo unit
Optional Items	Not priced as separate projects. Priced to be part of base project at same time.

Comments & Clarifications

This budgetary indicative pricing is provided by Dresser-Rand with the intention of entering into further and more detailed exchanges of information, discussions, and negotiations with Purchaser, which may ultimately result in a legally binding agreement in writing with Dresser-Rand. It is not an offer to sell the products or services referred to for the prices or schedule specified herein but is an estimate only which has been provided to Purchaser as requested. This budgetary indicative pricing l is based solely on Dresser-Rand standard design practices and quality assurance procedures. Client specifications were not provided for review. Any client specifications which may apply will need to be reviewed by Dresser-Rand before compliance with these specifications can be assured within the pricing and delivery schedules as proposed.

For the avoidance of doubt, this budgetary indicative pricing shall not be considered an offer for sale, and no purchase order issued against this budgetary indicative pricing shall be accepted by Dresser-Rand.

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From: Torpey, Steve <Steve.Torpey@p66.com>
Sent: Tuesday, January 23, 2024 12:28 PM
To: Olson, Kirby, ENV
Cc: Cook, John W; Elena Hofmann; Miller, Kenneth, ENV; Sanchez, Alex, ENV; Jones, Mark, ENV
Subject: RE: [EXTERNAL] Fw: Draft Final Control Cost Evaluation for DCP Operating Company's Linam Ranch Gas Plant

Good afternoon, Ms. Olson.

In response to the inquiry about Linam Ranch Gas Plant- Turbine Unit No. 31 (T-4700); the turbine the emissions upgrade was completed approximately October 29, 2023 and resumed operation the next day.

Please let me know if there are any further questions.

Steve

Steven Torpey, P.E.
Senior Air Permitting Engineer

O: 832-765-3444
2331 CityWest Blvd, HQ-08N-N860-03
Houston, TX 77042-2862
Phillips66.com

From: Torpey, Steve <Steve.Torpey@p66.com>
Sent: Thursday, January 25, 2024 3:21 PM
To: Jones, Mark, ENV
Cc: Cook, John W; Elena Hofmann; Miller, Kenneth, ENV; Sanchez, Alex, ENV; Olson, Kirby, ENV
Subject: [EXTERNAL] RE: Follow-up question / RE: Draft Final Control Cost Evaluation for DCP Operating Company's Linam Ranch Gas Plant
Attachments: 20240109_T02_Linam Ranch Gas Plant Unit 31(EU-31)_3000724_signedah.pdf

CAUTION: This email originated outside of our organization. Exercise caution prior to clicking on links or opening attachments.

Good afternoon, Mark.

Here is the emissions testing report for Unit 31. This has not been submitted through regular channels yet.

As for the question on Unit 32B, I am still waiting for an answer. I will forward an answer when I have it.

Steve

Steven Torpey, P.E.
Senior Air Permitting Engineer

O: 832-765-3444
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Houston, TX 77042-2862
Phillips66.com

EMISSIONS TEST REPORT

New Mexico Environment Department Periodic Test

Report #	20240109_T02
Test Date	Jan 09, 2024

Performed For:

DCP Midstream, LP
10 Desta Drive Suite 400 West
Midland, TX 79705

Location: Linam Ranch Gas Plant, Unit 31(EU-31), Lea County, NM
Turbine: Solar T-4700, 3000724

Performed By:

Slipstream Environmental Services, LLC

Mobile Lab: Lab T
772 Airfield Lane
Sheridan, WY 82801
josh.canfield@slipstreames.com
307-760-5262

Certification:

I certify, to the best of my knowledge, the test results are accurate and representative of the emissions from this source

Amy Harrah
Slipstream Environmental Services, LLC
(281) 323-1386
amy.harrah@slipstreamtesting.com

1.0 PERFORMANCE OVERVIEW SUMMARY

Results of the emissions test are summarized in Table 1-1 and Table 1-2 below; the site conditions are tabulated in Table 2-1: Test Conditions and Operational Data. Emissions rates and factors were calculated using the methods discussed in Section 6 – Emissions Calculations.

Table 1-1: Customer and Source Summary

TEST INFORMATION	
Test Prepared For	DCP Midstream, LP 10 Desta Drive, Suite 400 West Midland, TX 79705
Responsible Contact	Nick Case Phone: 575-802-5225 Email: Nicholas.L.Case@p66.com
Test Location	Linam Ranch Gas Plant
Unit Number	31(EU-31)
Test Date	Jan 09, 2024
Source	Solar T-4700
Source Serial Number	3000724
Site Rated Horsepower	4700
Source Purpose	Compressor
Manufacture Date	Jan 01, 1995
Permit Number	NSR#39-M9
Hour Meter Reading	1696.0

Table 1-2: Test Results

TEST RESULTS AND UNIT OPERATIONAL DATA					
Parameter	**Units**	**Average**	**Run 1**	**Run 2**	**Run 3**
Fuel Consumption	sft^3/hr	42,424	42,199	42,621	42,453
O2 Percentage	%	16.50	16.60	16.42	16.49
Adjusted O2 Percentage	%	16.38	16.47	16.29	16.38
Exhaust Flow Rate	$dsft^3/hr$	1,724,447	1,805,151	1,799,718	1,806,791
Turbine Power	bhp	4,694	4,693	4,693	4,697
NGP	%	99.87	99.8	99.9	99.9
NPT	%	89.90	90.3	89.9	89.5
Parameter	**Permitted**	**Average**	**Run 1**	**Run 2**	**Run 3**
CO					
ppmvd		5.31	3.96	5.38	6.58
ppm at 15% O2		6.92	5.27	6.89	8.59
lb/MMBTU HHV		0.02	0.01	0.02	0.02
g/bhp-hr		0.06	0.05	0.06	0.08
lb/hr	4.95	0.67	0.51	0.67	0.83
ton/yr		2.94	2.23	2.94	3.65
NOx					
ppmvd		14.38	14.26	14.52	14.35
ppm at 15% O2		18.77	18.99	18.59	18.73
lb/MMBTU HHV		0.07	0.07	0.07	0.07
g/bhp-hr		0.29	0.29	0.29	0.29
lb/hr	26.03	2.99	3.01	2.97	2.98
ton/yr		13.08	13.17	13.02	13.07

1.) VOC Calculated per NSPS JJJJ definition (does not include Methane, Ethane, or Formaldehyde concentrations). PPM values are expressed as a propane basis.

2.) Load percentage indicates maximum achievable load based on operating conditions on day of testing.

Remainder of Report Omitted for Brevity

From: Torpey, Steve <Steve.Torpey@p66.com>
Sent: Monday, February 5, 2024 1:13 PM
To: Olson, Kirby, ENV; Jones, Mark, ENV
Cc: Cook, John W; Elena Hofmann; Miller, Kenneth, ENV; Sanchez, Alex, ENV
Subject: RE: [EXTERNAL] RE: Follow-up question / RE: Draft Final Control Cost Evaluation for DCP Operating Company's Linam Ranch Gas Plant

Kirby,

I have done some research on ID 32B. At this point the request of bid is out. There is an expectation, not guaranteed, to be completed withing the second group of the Ozone precursor rule. This would have the controls updated by the end of 2025. I am sure you were hoping for a more definitive schedule, but this is the best that I have at this time.

I hope that this helps.

Steve

Steven Torpey, P.E.
Senior Air Permitting Engineer

O: 832-765-3444
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Houston, TX 77042-2862
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DCP Operating Company, LP
10 Desta Drive, Suite 500 W
Midland TX, 79705
Off: 432.620.4000

December 16, 2019

UPS Tracking No.:1Z 658 2E8 02 9426 8883

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department Air
Quality Bureau
525 Camino de los Marquez,
Suite 1 Santa Fe, NM 87505

Re: Four-Factor Analysis on Process Flaring and Startup, Shutdown, and Maintenance (SSM) Flaring – CAA Regional Haze Program
Artesia Gas Plant,
Eunice Gas Plant,
and Linam Gas Plant
DCP Operating Company, LP

Mr. Singleton,

Enclosed you will find Four Factor Analysis of Process Flaring and Startup, Shutdown, and Maintenance (SSM) Flaring for DCP's Artesia Gas Plant, Eunice Gas Plant and Linam Gas Plant.

DCP submitted the initial Four Factor Analysis without any analysis on non-steady state sources pursuant to NMED Guidance received on 9/23/2019. But we are submitting following attachment for DCP's three Regional Haze subject facilities as requested by November 14, 2019 letter from NMED,

If you have any questions or concerns, please feel free to contact me directly by phone at 432-215-8514 or via email at hshong@dcpmidstream.com.

Sincerely,

Sam Hong
Environmental Engineer
DCP Operating Company, LP

Enclosures
Attachment A – Artesia Gas Plant
Attachment B – Linam Gas Plant
Attachment C – Eunice Gas Plant

Midland Regional EHS File: 1.1.10

Attachment A:
DCP Midstream – Artesia Gas Plant
Process Flaring and Startup, Shutdown, and Maintenance (SSM) Flaring applicable to Four-Factor Analysis

Table 1. Summary of Process Flaring and SSM Flaring applicable to Four-Factor Analysis

Equipment	NO_X Hourly PTE (lb/hr)	NO_X Annual PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
Emergency Wet Gas Flare (Unit 22)	642.9	7.5	Yes	4918.4	49.9	Yes
Emergency Acid Gas Flare (Unit 23)	10.4	2.4	No	2001.0	328.2	Yes
Malfunction Flaring (Unit M1)	642.9	10.0	Yes	4918.4	10.0	Yes

Artesia Plant's facility SSM&M emission include plant turnaround, plant startup (post turnaround), condensate tank degassing during VRU downtime, gas piping degassing, pig launcher degassing, vacuum trucks, engine startup, compressor blowdown, emergency wet gas flare and acid gas flare SSM emissions. The permitted PTE are based on worst case scenario and actual year-to-year emissions vary but are significantly less than the permitted emissions based on which SSM activities were carried out during the year:

Table 2. Artesia 2016 EIQ Reported Process Flaring and SSM Flaring Emission

Unit No.	NOx	SO_2
	ton/yr	ton/yr
SSM (22)	0.57	0.31
SSM (23)	0.00	0.00
M1	2.03	7.45
Totals	**2.60**	**7.76**

NO_x emission is based on emission factor from AP-42 Table 13.5-1 (9/91) (Reformatted 1/95) and SO_2 emission is calculated based on gas analysis and an assumed 98% combustion of H_2S (conversion of H_2S to SO2 was assumed to be 100%).

Since the sources of SSM emission originates from normal plant activities, without decreasing number of causes (i.e. plant turnarounds and routine maintenance events), DCP notes that it's impractical to employ such measures in order to decrease flaring emissions. DCP further notes that Artesia plant currently has an existing BMP process and strive for continuous improvement on non-routine flare reduction.

Therefore, based on a comprehensive review of the non-steady state flaring emission sources, DCP concludes that there are no reasonable nor technically feasible emission reduction measures for flare sources subject to Four Factor Analysis at Artesia Gas Plant.

Attachment B:
DCP Midstream – Linam Gas Plant
Process Flaring and Startup, Shutdown, and Maintenance (SSM) Flaring applicable to Four-Factor Analysis

Table 1. Summary of Process Flaring and SSM Flaring applicable to Four-Factor Analysis

Equipment	NO_X Hourly PTE (lb/hr)	NO_X Annual PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
Amine Plant Flare East (Unit 2)	14.8	0.88	No	7751.21	45.59	**Yes**
ESD Flare (Unit 4A)	17.75	0.71	No	9301.45	4.13	No
AGI Flare (Unit AGI Flare)	287.65	4.33	No	2148.40	18.97	**Yes**
Malfunction (Unit Malfunction)	287.65	10	**Yes**	9301.45	10	**Yes**

Linam Plant's Unit 2 Gas Flare and AGI Flare emission include SSM emissions from the acid gas and AGI flares are calculated using the estimated maximum hourly and annual SSM flow rates routed to the respective flares. Malfunction. The permitted PTE are based on worst case scenario and actual year-to-year emissions vary but are significantly less than the permitted emissions based on which SSM activities were carried out during the year:

Table 2. 2016 EIQ Reported Process Flaring and SSM Flaring emission

Unit No.	NOx	SO_2
	ton/yr	ton/yr
Unit 2	0	3.28
AGI Flare	0	0
Malfunction	0.04	9.79

NO_x emission is based on emission factor from AP-42 Table 13.5-1 (9/91) (Reformatted 1/95) and SO_2 emission is calculated based on sulfur content of 5 gr S/100 scf.

Since the sources of SSM emission originates from normal plant activities, without decreasing number of causes (i.e. plant turnaround and routine maintenance events), DCP notes that it's impractical to employ such measures in order to decrease flaring emissions. DCP further notes that Linam plant currently has an existing BMP process and strive for continuous improvement on non-routine flare reduction.

Therefore, based on a comprehensive review of the non-steady state flaring emission sources, DCP concludes that there are no reasonable nor technically feasible emission reduction measures for flare sources subject to Four Factor Analysis at Linam Gas Plant.

Attachment C:
DCP Midstream – Eunice Gas Plant
Process Flaring and Startup, Shutdown, and Maintenance (SSM) Flaring applicable to Four-Factor Analysis

Table 1. Summary of Process Flaring and SSM Flaring applicable to Four-Factor Analysis

Equipment	NO_X Hourly PTE (lb/hr)	NO_X Annual PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
SSM Emissions (Unit SSM)	303.4	11.0	**Yes**	9368.2	257.2	**Yes**

Eunice Plant's facility SSM emission include plant turnaround, plant startup (post turnaround), condensate tank degassing during VRU downtime, gas piping degassing, pig launcher degassing, vacuum trucks (all tank cleanout), engine startup, compressor blowdown, acid gas flare, ESD flare, SRU acid gas flare and Amanda Booster Flare. The permitted PTE are based on worst case scenario and actual year-to-year emissions vary but are significantly less than the permitted emissions based on which SSM activities were carried out during the year:

Table 2. Eunice Plant 2016 EPN: SSM - Flare emission

Unit No.	NOx	SO_2
	ton/yr	ton/yr
Total SSM Emissions	0	0.68

NO_x emission is based on emission factor from AP-42 Table 13.5-1 (9/91) (Reformatted 1/95) and SO_2 emission is calculated based on gas analysis and an assumed 98% combustion of H_2S (conversion of H_2S to SO2 was assumed to be 100%).

Since the sources of SSM emission originates from normal plant activities, without decreasing number of causes (i.e. plant turnarounds and routine maintenance events), DCP notes that it's impractical to employ such measures in order to decrease flaring emissions. DCP further notes that Eunice plant currently has an existing BMP process and strive for continuous improvement on non-routine flare reduction.

Therefore, based on a comprehensive review of the non-steady state flaring emission sources, DCP concludes that there are no reasonable nor technically feasible emission reduction measures for flare sources subject to Four Factor Analysis at Eunice Gas Plant.

D.3 El Paso Natural Gas Company

Supporting documentation for El Paso Natural Gas Company is provided below. Facility-specific documentation is provided first, followed by documentation pertaining to multiple facilities and/or the owner/operator. The following documents are included in this section (in reading order):

- Blanco Compressor Station A:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (11/2019)
    - Follow-Up Submittal (2/14/2020)
    - Revised Four-Factor Analysis (6/5/2023)
- Pecos River Compressor Station:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (11/2019)
    - Follow-Up Submittal (2/14/2020)
- Washington Ranch Storage Facility:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (11/2019)
    - Follow-Up Submittal (2/14/2020)
- Multiple Facilities and/or Owner/Operator:
    - Follow-Up Submittal (2/23/2020)
    - Follow-Up Submittal (9/9/2020)
    - Follow-Up Submittal (10/9/2020)
    - Follow-Up Submittal (2/23/2021)
    - Follow-Up Submittal (5/26/2023)

NMED Final Cost Evaluation
El Paso Natural Gas Company - Blanco Compressor Station A

Facility Information

EPNG - Blanco A Comprressor Station	**Facility**
Fourteen 1950s vintage 2SLB RICE, 943 HP	**Units**
A01 through A14	**Unit IDs**
LEC Option 1	**Evaluated Pollution Control**
3.0	**Target Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2019	**Calendar year associated with cost estimates**
943	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		A01	A02	A03	A04	A05	A06	A07	A08	A09	A10	A11	A12	A13	A14	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 784,014	$ 784,014	$ 784,014	$ 784,014	$ 784,014	$ 784,014	$ 784,014	$ 784,014	$ 784,014	$ 784,014	$ 784,014	$ 784,014	$ 784,014	$ 784,014	EPNG FFA Update dated 6/5/23	Hoerbiger budgetary estimate dated 9/20/2019
Other Direct Capital Costs 1 ($)	ODC1	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	EPNG FFA Update dated 6/5/23	Per unit project costs for off-engine fuel system, automation panels, and new ignition system.
Other Direct Capital Costs 2 ($)	ODC2	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	EPNG FFA Update dated 6/5/23	Per unit project costs for project engineering, construction, installation, and commissioning.
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	EPNG FFA Update dated 6/5/23	Consistent with the methodology used by the EPA Cost Manual, this FFA evaluation is in terms of overnight costs.
Total Capital Costs - Direct ($)	TCC	$ 1,884,728	$ 1,884,728	$ 1,884,728	$ 1,884,728	$ 1,884,728	$ 1,884,728	$ 1,884,728	$ 1,884,728	$ 1,884,728	$ 1,884,728	$ 1,884,728	$ 1,884,728	$ 1,884,728	$ 1,884,728	-	PEC + ODC1 + ODC2 + IDC
Additional Capital ($)	AC	$ 188,473	$ 188,473	$ 188,473	$ 188,473	$ 188,473	$ 188,473	$ 188,473	$ 188,473	$ 188,473	$ 188,473	$ 188,473	$ 188,473	$ 188,473	$ 188,473	EPNG FFA Update dated 6/5/23	Contingency = 10% of TCC; mean value from EPA Cost Manual
Total Capital Investment ($)	TCI	$ 2,073,201	$ 2,073,201	$ 2,073,201	$ 2,073,201	$ 2,073,201	$ 2,073,201	$ 2,073,201	$ 2,073,201	$ 2,073,201	$ 2,073,201	$ 2,073,201	$ 2,073,201	$ 2,073,201	$ 2,073,201	-	TCC + AC
Interest Rate (%)	R	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	EPNG 2/23/2020 CFO letter and 10/9/2020 email	
Useful Life (yr)	Y	20	20	20	20	20	20	20	20	20	20	20	20	20	20	EPNG FFA Update dated 6/5/23	
Capital Recovery Factor	CRF	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 219,556	$ 219,556	$ 219,556	$ 219,556	$ 219,556	$ 219,556	$ 219,556	$ 219,556	$ 219,556	$ 219,556	$ 219,556	$ 219,556	$ 219,556	$ 219,556	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Engineering judgment	Incremental O&M of a LEC retrofit is expected to be negligible
Other Indirect Annual Costs ($/yr)	OAC	$ 82,928	$ 82,928	$ 82,928	$ 82,928	$ 82,928	$ 82,928	$ 82,928	$ 82,928	$ 82,928	$ 82,928	$ 82,928	$ 82,928	$ 82,928	$ 82,928	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 302,484	$ 302,484	$ 302,484	$ 302,484	$ 302,484	$ 302,484	$ 302,484	$ 302,484	$ 302,484	$ 302,484	$ 302,484	$ 302,484	$ 302,484	$ 302,484	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	46%	37%	26%	-119%	46%	46%	46%	46%	49%	46%	65%	46%	66%	46%	-	(Current actual emissions rate - Target emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	18.1	6.5	13.8	3.2	0.3	7.5	21.4	0.005	14.0	0.011	54.8	3.7	44.6	10.2	CY 2022/2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-	Not requested by EPNG
Projected Actual Emissions (ton/yr)	PAE	18.1	6.5	13.8	3.2	0.3	7.5	21.4	0.0	14.0	0.0	54.8	3.7	44.6	10.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	8.3	2.4	3.6	-3.8	0.1	3.5	9.9	0.002	6.8	0.005	35.9	1.7	29.2	4.7	-	PAE x Eff
2019$ Cost Effectiveness ($/ton)	**CE1**	**$36,273**	**$125,053**	**$84,397**	**($78,580)**	**$2,270,666**	**$87,255**	**$30,603**	**$135,785,836**	**$44,539**	**$61,720,835**	**$8,427**	**$179,421**	**$10,342**	**$64,207**	-	TAC/ER
Price Index	PI	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	-	CEPCI 2024* / CEPCI 2019 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$47,518**	**$163,820**	**$110,560**	**($102,940)**	**$2,974,573**	**$114,304**	**$40,090**	**$177,879,446**	**$58,346**	**$80,854,293**	**$11,039**	**$235,042**	**$13,548**	**$84,112**	-	CE1 x PI

NMED Final Cost Evaluation
El Paso Natural Gas Company - Blanco Compressor Station A

Facility Information

EPNG - Blanco A Comprressor Station	**Facility**
Fourteen 1950s vintage 2SLB RICE, 943 HP	**Units**
A01 through A14	**Unit IDs**
LEC Option 2	**Evaluated Pollution Control**
1.0	**Target Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2019	**Calendar year associated with cost estimates**
943	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		A01	A02	A03	A04	A05	A06	A07	A08	A09	A10	A11	A12	A13	A14	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 1,624,286	$ 1,624,286	$ 1,624,286	$ 1,624,286	$ 1,624,286	$ 1,624,286	$ 1,624,286	$ 1,624,286	$ 1,624,286	$ 1,624,286	$ 1,624,286	$ 1,624,286	$ 1,624,286	$ 1,624,286	EPNG FFA Update dated 6/5/23	Hoerbiger budgetary estimate dated 9/20/2019
Other Direct Capital Costs 1 ($)	ODC1	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	$ 350,714	EPNG FFA Update dated 6/5/23	Per unit project costs for off-engine fuel system, automation panels, and new ignition system.
Other Direct Capital Costs 2 ($)	ODC2	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	EPNG FFA Update dated 6/5/23	Per unit project costs for project engineering, construction, installation, and commissioning.
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	EPNG FFA Update dated 6/5/23	Consistent with the methodology used by the EPA Cost Manual, this FFA evaluation is in terms of overnight costs.
Total Capital Costs - Direct ($)	TCC	$ 2,975,000	$ 2,975,000	$ 2,975,000	$ 2,975,000	$ 2,975,000	$ 2,975,000	$ 2,975,000	$ 2,975,000	$ 2,975,000	$ 2,975,000	$ 2,975,000	$ 2,975,000	$ 2,975,000	$ 2,975,000	-	PEC + ODC1 + ODC2 + IDC
Additional Capital ($)	AC	$ 297,500	$ 297,500	$ 297,500	$ 297,500	$ 297,500	$ 297,500	$ 297,500	$ 297,500	$ 297,500	$ 297,500	$ 297,500	$ 297,500	$ 297,500	$ 297,500	EPNG FFA Update dated 6/5/23	Contingency = 10% of TCC; mean value from EPA Cost Manual
Total Capital Investment ($)	TCI	$ 3,272,500	$ 3,272,500	$ 3,272,500	$ 3,272,500	$ 3,272,500	$ 3,272,500	$ 3,272,500	$ 3,272,500	$ 3,272,500	$ 3,272,500	$ 3,272,500	$ 3,272,500	$ 3,272,500	$ 3,272,500	-	TCC + AC
Interest Rate (%)	R	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	EPNG 2/23/2020 CFO letter and 10/9/2020 email	
Useful Life (yr)	Y	20	20	20	20	20	20	20	20	20	20	20	20	20	20	EPNG FFA Update dated 6/5/23	
Capital Recovery Factor	CRF	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 346,564	$ 346,564	$ 346,564	$ 346,564	$ 346,564	$ 346,564	$ 346,564	$ 346,564	$ 346,564	$ 346,564	$ 346,564	$ 346,564	$ 346,564	$ 346,564	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Engineering judgment	Incremental O&M of a LEC retrofit is expected to be negligible
Other Indirect Annual Costs ($/yr)	OAC	$ 130,900	$ 130,900	$ 130,900	$ 130,900	$ 130,900	$ 130,900	$ 130,900	$ 130,900	$ 130,900	$ 130,900	$ 130,900	$ 130,900	$ 130,900	$ 130,900	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 477,464	$ 477,464	$ 477,464	$ 477,464	$ 477,464	$ 477,464	$ 477,464	$ 477,464	$ 477,464	$ 477,464	$ 477,464	$ 477,464	$ 477,464	$ 477,464	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	82%	79%	75%	27%	82%	82%	82%	82%	83%	82%	88%	82%	89%	82%	-	(Current actual emissions rate - Target emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	18.1	6.5	13.8	3.2	0.3	7.5	21.4	0.0	14.0	0.0	54.8	3.7	44.6	10.2	CY 2022/2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-	Not requested by EPNG
Projected Actual Emissions (ton/yr)	PAE	18.1	6.5	13.8	3.2	0.3	7.5	21.4	0.0	14.0	0.0	54.8	3.7	44.6	10.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	14.8	5.1	10.4	0.9	0.2	6.2	17.6	0.004	11.6	0.009	48.5	3.0	39.5	8.4	-	PAE x Eff
2019$ Cost Effectiveness ($/ton)	**CE1**	**$32,208**	**$92,770**	**$45,925**	**$542,677**	**$2,016,203**	**$77,477**	**$27,174**	**$120,568,938**	**$41,208**	**$54,804,063**	**$9,843**	**$159,314**	**$12,088**	**$57,012**	-	TAC/ER
Price Index	PI	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	-	CEPCI 2024* / CEPCI 2019 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$42,193**	**$121,529**	**$60,161**	**$710,907**	**$2,641,226**	**$101,494**	**$35,597**	**$157,945,309**	**$53,982**	**$71,793,322**	**$12,895**	**$208,702**	**$15,835**	**$74,686**	-	CE1 x PI

NMED Final Cost Evaluation
El Paso Natural Gas Company - Blanco Compressor Station A

Facility Information

EPNG - Blanco A Comprressor Station	**Facility**
Fourteen 1950s vintage 2SLB RICE, 943 HP	**Units**
A01 through A14	**Unit IDs**
LEC Option 3	**Evaluated Pollution Control**
0.5	**Target Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2019	**Calendar year associated with cost estimates**
943	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		A01	A02	A03	A04	A05	A06	A07	A08	A09	A10	A11	A12	A13	A14	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 1,334,282	$ 1,334,282	$ 1,334,282	$ 1,334,282	$ 1,334,282	$ 1,334,282	$ 1,334,282	$ 1,334,282	$ 1,334,282	$ 1,334,282	$ 1,334,282	$ 1,334,282	$ 1,334,282	$ 1,334,282	EPNG FFA Update dated 6/5/23	Hoerbiger budgetary estimate dated 9/20/2019
Other Direct Capital Costs 1 ($)	ODC1	$ 470,556	$ 470,556	$ 470,556	$ 470,556	$ 470,556	$ 470,556	$ 470,556	$ 470,556	$ 470,556	$ 470,556	$ 470,556	$ 470,556	$ 470,556	$ 470,556	EPNG FFA Update dated 6/5/23	Per unit project costs for off-engine fuel system, automation panels, and new ignition system.
Other Direct Capital Costs 2 ($)	ODC2	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	EPNG FFA Update dated 6/5/23	Per unit project costs for project engineering, construction, installation, and commissioning.
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	EPNG FFA Update dated 6/5/23	Consistent with the methodology used by the EPA Cost Manual, this FFA evaluation is in terms of overnight costs.
Total Capital Costs - Direct ($)	TCC	$ 2,804,838	$ 2,804,838	$ 2,804,838	$ 2,804,838	$ 2,804,838	$ 2,804,838	$ 2,804,838	$ 2,804,838	$ 2,804,838	$ 2,804,838	$ 2,804,838	$ 2,804,838	$ 2,804,838	$ 2,804,838	-	PEC + ODC1 + ODC2 + IDC
Additional Capital ($)	AC	$ 280,484	$ 280,484	$ 280,484	$ 280,484	$ 280,484	$ 280,484	$ 280,484	$ 280,484	$ 280,484	$ 280,484	$ 280,484	$ 280,484	$ 280,484	$ 280,484	EPNG FFA Update dated 6/5/23	Contingency = 10% of TCC; mean value from EPA Cost Manual
Total Capital Investment ($)	TCI	$ 3,085,321	$ 3,085,321	$ 3,085,321	$ 3,085,321	$ 3,085,321	$ 3,085,321	$ 3,085,321	$ 3,085,321	$ 3,085,321	$ 3,085,321	$ 3,085,321	$ 3,085,321	$ 3,085,321	$ 3,085,321	-	TCC + AC
Interest Rate (%)	R	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	EPNG 2/23/2020 CFO letter and 10/9/2020 email	
Useful Life (yr)	Y	20	20	20	20	20	20	20	20	20	20	20	20	20	20	EPNG FFA Update dated 6/5/23	
Capital Recovery Factor	CRF	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	0.1059	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 326,741	$ 326,741	$ 326,741	$ 326,741	$ 326,741	$ 326,741	$ 326,741	$ 326,741	$ 326,741	$ 326,741	$ 326,741	$ 326,741	$ 326,741	$ 326,741	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Engineering judgment	Incremental O&M of a LEC retrofit is expected to be negligible
Other Indirect Annual Costs ($/yr)	OAC	$ 123,413	$ 123,413	$ 123,413	$ 123,413	$ 123,413	$ 123,413	$ 123,413	$ 123,413	$ 123,413	$ 123,413	$ 123,413	$ 123,413	$ 123,413	$ 123,413	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 450,154	$ 450,154	$ 450,154	$ 450,154	$ 450,154	$ 450,154	$ 450,154	$ 450,154	$ 450,154	$ 450,154	$ 450,154	$ 450,154	$ 450,154	$ 450,154	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	91%	90%	88%	64%	91%	91%	91%	91%	91%	91%	94%	91%	94%	91%	-	(Current actual emissions rate - Target emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	18.1	6.5	13.8	3.2	0.3	7.5	21.4	0.0	14.0	0.0	54.8	3.7	44.6	10.2	CY 2022/2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-	Not requested by EPNG
Projected Actual Emissions (ton/yr)	PAE	18.1	6.5	13.8	3.2	0.3	7.5	21.4	0.0	14.0	0.0	54.8	3.7	44.6	10.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	16.4	5.8	12.1	2.1	0.3	6.8	19.5	0.004	12.8	0.010	51.7	3.3	42.1	9.3	-	PAE x Eff
2019$ Cost Effectiveness ($/ton)	**CE1**	**$27,372**	**$77,230**	**$37,203**	**$218,295**	**$1,713,480**	**$65,844**	**$23,094**	**$102,466,127**	**$35,208**	**$46,575,512**	**$8,714**	**$135,394**	**$10,702**	**$48,452**	-	TAC/ER
Price Index	PI	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	-	CEPCI 2024* / CEPCI 2019 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$35,858**	**$101,172**	**$48,736**	**$285,967**	**$2,244,659**	**$86,255**	**$30,253**	**$134,230,626**	**$46,122**	**$61,013,921**	**$11,415**	**$177,366**	**$14,020**	**$63,472**	-	CE1 x PI

NMED Final Cost Evaluation
El Paso Natural Gas Company - Blanco Compressor Station A

Facility Information

EPNG - Blanco A Comprressor Station	**Facility**
Fourteen 1950s vintage 2SLB RICE, 943 HP	**Units**
A01 through A14	**Unit IDs**
Replacement with new RICE	**Evaluated Pollution Control**
0.5	**Target Emissions Rate (g NOx/bhp-hr)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired spark ignited lean-burn RICE >500 and <1875 bhp.

Supporting Information

2020	**Calendar year associated with cost estimates**
943	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		A01	A02	A03	A04	A05	A06	A07	A08	A09	A10	A11	A12	A13	A14	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 3,043,061	$ 3,043,061	$ 3,043,061	$ 3,043,061	$ 3,043,061	$ 3,043,061	$ 3,043,061	$ 3,043,061	$ 3,043,061	$ 3,043,061	$ 3,043,061	$ 3,043,061	$ 3,043,061	$ 3,043,061	9/8/20 info from EPNG	All-in estimate ($/HP) x Maximum Capacity (HP)
Interest Rate (%)	R	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	8.53%	EPNG 2/23/2020 CFO letter and 10/9/2020 email	
Useful Life (yr)	Y	30	30	30	30	30	30	30	30	30	30	30	30	30	30	ERG experience based on discussions with RICE manufacturers	
Capital Recovery Factor	CRF	0.0933	0.0933	0.0933	0.0933	0.0933	0.0933	0.0933	0.0933	0.0933	0.0933	0.0933	0.0933	0.0933	0.0933	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Engineering judgment	Incremental O&M reasonably negligible
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	$ 283,936	-	ACC + OMC
NOx Control Efficiency (%)	Eff	91%	90%	88%	64%	91%	91%	91%	91%	91%	91%	94%	91%	94%	91%	-	(Current actual emissions rate - Target emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	18.1	6.5	13.8	3.2	0.3	7.5	21.4	0.0	14.0	0.0	54.8	3.7	44.6	10.2	CY 2022/2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-	Not requested by EPNG
Projected Actual Emissions (ton/yr)	PAE	18.1	6.5	13.8	3.2	0.3	7.5	21.4	0.0	14.0	0.0	54.8	3.7	44.6	10.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	16.4	5.8	12.1	2.1	0.3	6.8	19.5	0.004	12.8	0.010	51.7	3.3	42.1	9.3	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$17,265**	**$48,713**	**$23,466**	**$137,690**	**$1,080,782**	**$41,531**	**$ 14,566**	**$ 64,630,739**	**$ 22,207**	**$ 29,377,609**	**$ 5,496**	**$ 85,400**	**$ 6,750**	**$ 30,561**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 and thus assumed costs are in 2020$
Price Index	PI	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	-	CEPCI 2024* / CEPCI 2020 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$23,135**	**$65,276**	**$31,445**	**$184,505**	**$1,448,247**	**$55,652**	**$19,519**	**$86,605,190**	**$29,758**	**$39,365,995**	**$7,365**	**$114,436**	**$9,045**	**$40,952**	-	CE1 x PI

NMED Final Cost Evaluation
El Paso Natural Gas Company - Blanco Compressor Station A

Facility Information

EPNG - Blanco A Comprressor Station	**Facility**
Fourteen 1950s vintage 2SLB RICE, 943 HP	**Units**
A01 through A14	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Target Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2019	**Calendar year associated with cost estimates**
943	**Maximum Power Output (hp/unit)**
2195	**Operating Schedule (hr/yr, average)**

Economic Evaluation

Cost Component		All Units (Combined)	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	On 2/14/20, EPNG provided a $1469/hp all-in Total Capital Cost (TCC) metric for EMD. On 9/9/20, EPNG provided an alternate cost estimate developed using "the KM-Cost Estimating Group's Developmental Cost Estimating Tool". The alternate estimate applied an unusual and insufficiently documented methodology that involved a base cost estimate for replacement RICE that was adjusted using EMD-specific costs and RICE-specific costs. Using detailed cost information provided by other facilities, NMED developed a TCC metric of $2,084/hp (2023$) for the installation of EMD. Costs associated with requisite substation and utility line upgrades were estimated separately and added to TCC to estimate Total Capital Investment (TCI).
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ 21,002,266	See Note	
Additional Capital ($)	AC	$ 3,225,000	EPNG estimate dated 9/9/20 and ERG experience	0.3 miles of medium voltage line @ $750k/mile; $3M substation upgrade
Total Capital Investment ($)	TCI	$ 24,227,266	-	TCC + AC
Interest Rate (%)	R	8.53%	EPNG 2/23/2020 CFO letter and 10/9/2020 email	
Useful Life (yr)	Y	25	EPNG estimate dated 9/9/20	
Capital Recovery Factor	CRF	0.0980	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 2,373,198	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 616,597	-	AED + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 1,231,597	Engineering estimate	Assumes units at 60% load, 95% efficiency and a $0.10/kWh price
Associated non-electricity O&M ($/yr)	AOM	$ -	Engineering judgment	Assumed to be negligible
Annual Fuel Credit ($/yr)	AFC	$ (615,000)	EPNG 2/23/21 email	Cost of fuel based on calendar year 2016 operation
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 2,989,794	-	ACC + OMC
NOx Control Efficiency (%)	Eff	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	198.1	CY 2022/2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by EPNG
Projected Actual Emissions (ton/yr)	PAE	198.1	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	198.1	-	PAE x Eff
2019$ Cost Effectiveness ($/ton)	**CE1**	**$15,090**	-	TAC/ER
Price Index	PI	1.31	-	CEPCI 2024* / CEPCI 2019 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$19,768**	-	CE1 x PI

El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

November 1, 2019

FedEx Tracking No.: 7806 6602 2181

Ms. Liz Bisbey-Kuehn
Chief, Air Quality Bureau
New Mexico Environment Department
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505

Re: Submittal of Four-Factor Analysis on Control Measures under the Clean Air Act Regional Haze Program
El Paso Natural Gas Company, L.L.C.
Blanco Compressor Station A

Dear Ms. Bisbey-Kuehn,

On July 18, 2019 El Paso Natural Gas Company, L.L.C. (EPNG) received notification from New Mexico Environment Department (NMED) that the Blanco Compressor Station A in San Juan County, New Mexico is a facility subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

EPNG evaluated three technically feasible options for controls of nitrogen oxides (NOx) for the fourteen (14) Cooper Bessemer GMV10-TF reciprocating internal combustion engines that are located at the compressor station. The control options are listed in Table 1 of the enclosed four-factor analysis. Table 2 outlines the cost effectiveness (dollars per ton of pollutant reduction) of these control options based on 2016 emissions inventory data.

As requested by NMED, this four-factor analysis is being submitted no later than November 1, 2019. If you have any questions, please contact me at (719) 520-3786 or via email at Travis_Ray@kindermorgan.com.

Sincerely,
El Paso Natural Gas Company, L.L.C.

Travis Ray
EHS Specialist

Cc: Mark Jones, NMED
Kerwin Singleton, NMED

Enclosure



El Paso Natural Gas Company, L.L.C.
Blanco Compressor Station A
San Juan County, New Mexico

Four-Factor Analysis for Regional Haze Planning in New Mexico

November 2019

Prepared for:

El Paso Natural Gas Company, L.L.C.
2 North Nevada Avenue
Colorado Springs, CO 80903

El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

Prepared by:

Alliant Environmental, LLC
7804 Pan American Fwy. NE, Suite 5
Albuquerque, NM 87109

ALLIANT ENVIRONMENTAL, LLC

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ACRONYMS AND ABREVIATIONS

BACT	Best Available Control Technology
CAA	Clean Air Act
CIA	Class I Area
EFI	Electronic Fuel Injection
EPA	Environmental Protection Agency
gr/dscf	Grains per Dry Standard Cubic Foot
HAP	Hazardous Air Pollutant
lb/hr	Pounds per Hour
MACT	Maximum Achievable Control Technology
MID	Most Impaired Days
MMBtu/hr	Million British Thermal Units per Hour
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NMAC	New Mexico Administrative Code
NMED	New Mexico Environment Department
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
PTE	Potential to Emit
PSD	Prevention of Significant Deterioration
RICE	Reciprocating Internal Combustion Engine
SO_2	Sulfur Dioxide
tpy	Tons per Year
WRAP	Western Regional Air Partnership

EXECUTIVE SUMMARY

The Blanco Compressor Station A, owned and operated by El Paso Natural Gas Company, L.L.C. (EPNG), is located near Bloomfield in San Juan County, New Mexico. The Blanco Compressor Station A is a natural gas compressor station that compresses natural gas for the purpose of transportation to another facility or a major transportation pipeline.

The New Mexico Environment Department (NMED) has requested a report containing a complete Four-Factor Analysis for the Blanco Compressor Station A. The analysis has identified possible NO_x and SO_2 control options for the fourteen (14) compressor engines operating at the Blanco Compressor Station A and followed the Western Regional Air Partnership (WRAP) assessment protocol by assessing the following four factors:

Factor 1: Cost of compliance;
Factor 2: Time necessary for compliance;
Factor 3: Energy and non-air quality environmental impacts; and
Factor 4: Remaining useful life of the source.

NMED is requiring that a separate analysis be performed for each pollutant (nitrogen oxide and sulfur dioxide) with a potential to emit (PTE) greater than ten (10) pounds per hour (lb/hr). As sulfur dioxide (SO_2) emissions from the Blanco Compressor Station A are less than the 10 lb/hr threshold, an analysis of control options was not completed.

The evaluation concluded that there are no technically feasible options to reduce nitrogen oxide (NO_x) emissions for the engines at the Blanco Compressor Station A. Taking into account the age of the engines, the costs associated with the installation of controls or engine modifications, possible loss in engine efficiency, and the timeframes in which the modifications would be completed, any changes to reduce the NO_x emissions from the engines is not practicable at this time. NO_x control strategy options that are evaluated as part of the Four-Factor Analysis for the engines are included in Table 1. The table also shows the estimated NO_x emission rate for each control option.

TABLE 1: NO_X CONTROL OPTIONS FOR ENGINES

	Option 1	Option 2	Option 3
NO_x Target	3 g/bhp-hr	1 g/bhp-hr	Alt. low-NO_x Option to get 0.5 g/bhp-hr
Scope Summary	High-pressure EFI & electric blower	Same as Option 1 + Exhaust manifold replacement & catalytic silencer	High-pressure EFI with engine uprate of 9-units & retire 5-units
HyperFuel	X	X	X
Engine Auxiliary Cooling System	X	X	
Wet to Dry Manifold Conversion		X	
Muffler with Oxidation Catalyst		X	
Cylinder Heads with PCC		X	
Turbocharger			X
Compressor Cylinder Upgrade			X
Power Cylinder Upgrade			X
Cost per engine	$784,014	$1,624,286	$1,334,282
Subtotal	$10,976,196	$22,740,004	$12,008,538
Off-Engine Fuel System	$500,000	$500,000	$500,000
Automation Panels	$3,500,000	$3,500,000	$2,250,000
New Ignition System	$910,000	$910,000	$585,000
Pulsation Bottles	$0	$0	$900,000
Construction, Inspection, Commissioning, & Company Labor	$10,500,000	$14,000,000	$9,000,000
TOTAL COST	**$26,386,196**	**$41,650,004**	**$25,243,538**
Cost per Unit	$1,884,728.29	$2,975,000.29	$2,804,837.56
Cost Effectiveness ($/ton reduced, per engine)	See Table 2	See Table 2	See Table 2
Compliance Timeframe (after NSR permit issuance)	12 months	36 months	36 months
Energy and Non-Air Impacts	Waste generation and disposal, water consumption, electrical power use, combustion emissions from project equipment, potential decrease in engine efficiency	Waste generation and disposal, water consumption, electrical power use, combustion emissions from project equipment, potential decrease in engine efficiency	Waste generation and disposal, water consumption, electrical power use, combustion emissions from project equipment, potential decrease in engine efficiency
Remaining Useful Life	20 years (maximum)	20 years (maximum)	20 years (maximum)

TABLE 2: COST EFFECTIVENESS BASED ON 2016 EMISSIONS INVENTORY

		Option 1			Option 2			Option 3		
Unit ID	2016 NOx Emissions (TPY)	2016 NOx Emissions Based on 3.0 g/bhp-hr (TPY)	NOx Reduction (TPY)	Cost Effectiveness ($/ton reduced)	2016 NOx Emissions Based on 1.0 g/bhp-hr (TPY)	NOx Reduction (TPY)	Cost Effectiveness ($/ton reduced)	2016 NOx Emissions Based on 0.5 g/bhp-hr (TPY)	NOx Reduction (TPY)	Cost Effectiveness ($/ton reduced)
A01	73.711	20.993	52.718	$ 35,751.27	6.998	66.713	$ 44,593.96	3.499	70.212	$ 39,948.18
A02	0.025	0.007	0.018	$ 1,851,502.89	0.002	0.022	$ 2,908,631.75	0.001	0.023	$ 2,738,983.48
A03	54.915	15.640	39.275	$ 47,988.12	5.213	49.701	$ 59,857.46	2.607	52.308	$ 53,621.53
A04	1.093	0.311	0.782	$ 411,735.39	0.104	0.989	$ 32,661.78	0.052	1.041	$ 2,694,649.96
A05	3.081	0.878	2.204	$ 855,297.53	0.293	2.789	$ 1,066,846.07	0.146	2.935	$ 955,702.52
A06	0.613	0.175	0.439	$ 1,057,784.91	0.058	0.555	$ 1,323,161.13	0.029	0.584	$ 1,165,802.68
A07	65.341	18.609	46.732	$ 40,330.69	6.203	59.138	$ 50,306.05	3.102	62.240	$ 45,065.19
A08	0.019	0.005	0.014	$ 1,858,886.31	0.002	0.017	$ 2,923,380.32	0.001	0.018	$ 2,753,617.72
A09	27.382	7.798	19.584	$ 96,240.22	2.599	24.783	$ 120,044.19	1.300	26.082	$ 107,538.04
A10	0.019	0.005	0.014	$ 1,858,886.31	0.002	0.017	$ 2,923,380.32	0.001	0.018	$ 2,753,617.72
A11	48.253	13.743	34.511	$ 54,612.79	4.581	43.673	$ 68,120.68	2.290	45.963	$ 61,023.89
A12	0.016	0.005	0.012	$ 1,862,578.02	0.002	0.015	$ 2,930,754.60	0.001	0.016	$ 2,760,934.84
A13	82.061	23.371	58.690	$ 32,113.26	7.790	74.271	$ 40,056.13	3.895	78.166	$ 35,883.10
A14	0.019	0.005	0.014	$ 1,858,886.31	0.002	0.017	$ 2,923,380.32	0.001	0.018	$ 2,753,617.72
		Average Cost Effectiveness ($/ton reduced)		$ 851,613.86	Average Cost Effectiveness ($/ton reduced)		$ 1,243,941.05	Average Cost Effectiveness ($/ton reduced)		$ 1,351,429.04

SECTION 1.0 INTRODUCTION

In 1977, serious degradation of scenic views at national parks and wilderness areas prompted Congress to require the U.S. Environmental Protection Agency (EPA) to take action. Initial work was conducted to identify specific facilities whose emissions clearly caused regional haze in these nationally treasured places, and the eventual result was the 1999 Regional Haze Rule. This rule mandates gradual progress toward restoring "natural" visibility conditions by the year 2064 at designated national parks, wilderness areas, monuments, forests, seashores, and wildlife refuges, collectively referred to as Class I areas (CIA). The rule was revised in 2017 to strengthen visibility protection, emphasizing that states must reduce human-caused emissions of air pollutants that impair visibility at these special places held in the public trust.

On July 1, 1999, the EPA published regulations implementing Section 169A of the Clean Air Act (CAA), establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule). The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. The Regional Haze Rule established a schedule setting forth deadlines by which the States must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter. The second planning period Regional Haze SIPs must be submitted to EPA for review by July 31, 2021.

For the second planning period, EPA guidance recommends that each state should evaluate about 80 percent of emissions impact at each CIA from major and minor stationary sources along with area sources to ensure a reasonably large fraction of emissions potentially impacting CIA visibility deterioration. The over-arching goal in assessing emissions is to ensure states identify anthropogenic sources that are most likely impacting the 20 percent most impaired days (MID) at one or more Class I areas.

NMED identified twenty-four (24) Title V permitted facilities across New Mexico that may potentially have an impact on visibility at Federal Class I Areas protected by the Regional Haze Rule. This determination was based on a screening analysis, the Q/d evaluation, developed by the Western Regional Air Partnership (WRAP), along with guidance from the U.S. Environmental Protection Agency (EPA).

EPNG has prepared a Four-Factor Analysis for the control of nitrogen oxides (NO_x) emissions from the Blanco Compressor Station A. The evaluation is in response to the NMED letter dated July 18, 2019. The evaluation includes an assessment of potentially available emission reduction measures for the four statutory factors listed in 40 CFR 51.308(f)(2), and takes into consideration EPA's *Air Pollution Control Cost Manual, Assessment of Non-EGU NO_x Emission Controls, Cost of Controls, and Time for Compliance Final TSD,* and the EPA's RACT/BACT/LAER Clearinghouse. Technically feasible NO_x emission reduction measures are evaluated for the following four factors:

- Factor 1: The cost of compliance;
- Factor 2: The time necessary to achieve compliance;

• Factor 3: The energy and non-air quality environmental impacts; and
• Factor 4: The remaining useful life of any existing source subject to such requirements.

The Four-Factor Analysis for the Blanco Compressor Station A is presented in the following sections.

SECTION 2.0 SOURCE CATEGORY ANALYSIS

2.1 FACILITY DESCRIPTION

The Blanco Compressor Station A is a natural gas compressor station that compresses natural gas for the purpose of transportation to another facility or a major transportation pipeline. Emission sources located at the Blanco Compressor Station include fourteen (14) Cooper Bessemer GMV10-TF natural gas-fired reciprocating internal combustion engines (RICE).

The Blanco Compressor Station A currently operates under Title V permit number P048-R3 and New Source Review (NSR) permit number 0613-M10. NSR permit number 0613-M10 was issued jointly to three (3) companies as part of an NMED and EPA agreement that established common control between the three (3) companies and three (3) of their adjacent facilities. These companies include: EPNG, Harvest Midstream and Enterprise Products Operating, L.L.C.

2.2 CLEAN AIR ACT AND STATE REGULATIONS REQUIRING CONTROL

This Four-Factor Analysis is being requested by NMED and the EPA under the Federal Clean Air Act, 42 USC §7401; and the Code of Federal Regulations, 40 CFR §51.300 to §51.309 (regional Haze Rule).

There are currently no air pollution controls installed on the compressor engines evaluated in this report. The compressor engines at the Blanco Compressor Station A were constructed in 1953 and do not have any Federal or State regulatory requirements to control emissions. An air permit for the Blanco Compressor Station A is required under 20.2.74 NMAC (PSD construction permits) and 20.2.70 NMAC (operating permits) as the site is a major source of air pollutants.

2.3 NO_X AND SO_2 EMISSIONS FROM THE SOURCE CATEGORY

NO_x and SO_2 emissions are generated by the engines from the combustion of natural gas, which is used as fuel. Engine manufacturer emission factors, EPA developed emission factors (AP-42), engine manufacturer rated horsepower, and other engine manufacturer rated capacities are used to estimate emissions for RICE. As these engines are fired with natural gas and SO_2 emissions are based on the grains of Sulfur per dry standard cubic foot of gas (gr/dscf), there are negligible SO_2 emissions. The estimated and permitted value of NO_x emissions for the engines at the Blanco Compressor Station A are 21.9 lb/hr (each) and SO_2 emissions from the engines are estimated to be less than 1.0 lb/hr (each).

2.3.1 NO_X CONTROL OPTIONS

The engines do not currently have controls installed and operate under the original manufacturer design. The potential control options that were analyzed include:

- Option 1: High pressure electronic fuel injection to achieve a NOx target of 3 g/hp-hr
- Option 2: High-pressure electronic fuel injection plus exhaust manifold replacement and catalytic silencer to achieve a NOx target of 1 g/hp-hr

- Option 3: alternate option including high-pressure electronic fuel injection, engine uprate of 9 units and potential retirement of 5 units.

See Table 1 for more information. Selective Catalytic Reduction (SCR) was evaluated but eliminated due to technical infeasibility for this engine type.

SECTION 3.0 FOUR-FACTOR ANALYSIS

3.1 FACTOR 1: COST OF COMPLIANCE

Control costs include both the capital costs associated with the purchase and installation of retrofit and new control systems, as well as the net annual costs (annual recurring costs) associated with system operation. The basic components of total capital costs are direct capital costs, which includes purchased equipment and installation costs, and indirect capital expenses.

Direct capital costs consist of such items as purchased equipment, instrumentation and process controls, ductwork and piping, electrical components, and structural and foundation costs. Labor costs associated with construction and installation are also included in this category.

Indirect capital expenses are comprised of engineering and design costs, contractor fees, supervisory expenses, and startup and performance testing. Contingency costs – which represent such costs as construction delays, increased labor and equipment costs, and design modifications – are an additional component of indirect capital expenses. Capital costs also include the cost of process modifications. Annual costs include amortized costs of capital investment, as well as costs of operating labor, utilities, and waste disposal.

Only control options that are appropriate to the engines at the Blanco Compressor Station A were analyzed. See Table 1 for a list of the potential control costs.

3.2 FACTOR 2: TIME NECESSARY FOR COMPLIANCE

The time necessary for compliance is separate from the other three factors. The time necessary for compliance depends on reasonable installation times and compliance deadlines for selected control measures. Combustion modifications and post-combustion NO_x controls may require significant time for engineering, construction, and facility preparedness. As an exact timeframe cannot be projected for the analyzed control options, an estimate was made for each option. Furthermore, not all engines would be able to be modified simultaneously as pressure must be maintained within the transmission pipeline at all times. Estimates were made between 1 and 3 years, after the issuance of the revised construction permit from NMED, depending on the control selected. See Table 1 for the estimated time frames to fully implement each control option.

3.3 FACTOR 3: ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS

Various controls may impact energy use; equipment efficiency; fuel usage; non-air impacts such as noise pollution, odor, climate impacts, and solid, liquid, or hazardous waste generation; and deposition of atmospheric pollutants on land or water. The analyzed controls may impact waste generation and disposal, water consumption, electrical power use, and potentially decrease engine efficiency.

3.4 FACTOR 4: REMAINING USEFUL LIFE OF THE SOURCE

The remaining useful life of individual emissions units (engines) can vary greatly depending on

the age of the unit, size of the unit, maintenance frequency, and other factors. As the engines at the Blanco Compressor Station A are over 60 years old, it is difficult to estimate the remaining useful life of these sources. The EPA's Air Pollution Control Cost Manual suggests the remaining useful life should be based on the control method and not the emissions source itself; therefore, it is assumed that the remaining useful life of any chosen control or modification is 20 years.

SECTION 4.0 REFFERENCES

1. Western Regional Air Partnership and Western States Air Resources Council. *Overview of Regional Haze Planning.* May 7, 2019.

2. Western Regional Air Partnership and Western States Air Resources Council. *WRAP Reasonable Progress Source Identification and Analysis Protocol for Second 10-Year Regional Haze State Implementation Plans.* February 27, 2019.

3. U.S. EPA Office of Air Quality Planning and Standards. *EPA Air Pollution Control Cost Manual, Sixth Edition.* EPA/452/B-02-001. January 2002.

4. U.S. EPA Office of Air and Radiation. *Assessment of Non-EGU NO_x Emission Controls, Cost of Controls, and Time for Compliance Final TSD.* August 2016.

5. EPA's RACT/BACT/LAER Clearinghouse. https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information

El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

VIA E-MAIL: mark.jones@state.nm.us; kerwin.singleton@state.nm.us

February 14, 2020

Mr. Mark Jones
Mr. Kerwin Singleton
NMED Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

RE: Response to the Request for Additional Information for Four-Factor Analyses under the Regional Haze Program

Dear Mr. Jones and Mr. Singleton:

This letter addresses the additional information request for the El Paso Natural Gas Company, L.L.C. (EPNG) – Blanco A Compressor Station Four-Factor Analysis ("Analysis") received on December 23, 2019. For the Blanco A Compressor Station there were a total of fifteen item requests pertaining to the NO_X emissions for the engines. Please see the responses for each item request below.

a. *Please provide a discussion that explains the various control technologies listed in Table 1; why certain technologies are required for each options 1, 2, and 3; and the associated technical information for all of the listed technologies (e.g., HyperFuel, cylinder upgrades, wet to dry manifold conversion).*

   The attached proposal from Hoerbiger Engineered Solutions (HES) provides more details of the options listed in Table 1 of the Analysis. EPNG requested information on technologies to achieve 5 g/hp-hr NOx, 3 g/hp-hr NOx, and less than 1 g/hp-hr NOx. HES concluded that the technologies to achieve 5 g/hp-hr and 3 g/hp-hr NOx are the same so the 3 g/hp-hr option is noted as Option 1, the 1 g/hp-hr option is noted as Option 2, and the <1 g/hp-hr option is noted as Option 3.

   The listed options represent combustion controls that prevent NOx formation rather than an add-on control that reduces post-combustion NOx emissions. The components that are included in these retrofits (Hyperfuel, cylinder upgrades, wet to dry manifold conversion, etc.) work together to provide optimal air-fuel mixture to improve emissions performance.

b. *Oxidation catalysts are listed as a proposed NOx control, but controlling NOx emissions requires a technology that includes a reduction catalyst, such as Selective Catalytic Reduction (SCR). Please explain and clarify the inclusion of oxidation catalyst technology in Table 1.*

   To obtain NOx reduction with clean burn technology, the air-to-fuel ratio must be driven lean. There is a tradeoff relationship between NOx and CO when air fuel ratio is adjusted (i.e., as NOx is reduced, CO may increase). The oxidation catalyst is to prevent the CO from increasing beyond currently permitted levels when the NOx is reduced.

c. *Consider and include an analysis on typical retrofit low-emissions combustion technology (LEC) for internal combustion engines such as, air-fuel ratio controllers, improved combustion chamber design, enhanced air-fuel mixing, and improved ignition system.*

These items were all taken into consideration in the development of the three options. See attached proposal from Hoerbiger.

d. *Explain how engine efficiency is potentially lost due to the controls listed in Table 1 and specify which controls cause a loss in efficiency.*

The technology itself does not cause a loss in engine thermal efficiency; it is a result of the tradeoff between air fuel ratio and heat rate. As mentioned above, the air fuel ratio has to be driven lean to acquire the NOx reduction.

e. *Provide the basis for the costs used in the cost analysis in Table 1.*

Please see the attached Hoerbiger proposal for details of the costs

f. *Consider and include an analysis on CleanBurn™ Technologies (CBT), which are equivalent to LEC technologies, but designed specifically for Cooper Bessemer engines. Please identify any CBT that may be analogous to any of the technologies already listed in Table 1 of the November 2019 four-factor submittal.*

Please see item c above.

g. *Provide the manufacturer's and/or vendor's specifications and cost used for the four-factor analysis.*

Please see attached Hoerbiger proposal.

h. *Include a technical feasibility analysis for selective catalytic reduction (SCR).*

U.S. EPA, Ap-42, Section 3.2 "Natural Gas-Fired Reciprocating Engines" currently states:

> "For engines which typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia to gain the reductions needed."

A review of the RBLC tables found no examples of SCR being used as a control for 2SLB engines. The lack of availability or comparable use of an SCR on these Cooper-Bessemer engines presents the case that this control technology is considered technically infeasible.

i. *Consider Good Combustion Practice's (GCP) and routine maintenance as controls and provide the details of a maintenance schedule, employee training and operating procedures to achieve emissions reductions.*

EPNG employs GCP at Blanco A via the routine maintenance schedule pursuant to A314.B in NSR Permit No. 0613-M10. In addition, EPNG performs periodic testing on the compressor engines

pursuant to A314.A in order to monitor NO_X, CO, and VOC emissions. Additionally, employees are required to complete training on equipment before they are authorized to operate it, and standard operating procedures and maintenance practices have been developed based on manufacturer's recommendations to keep the equipment in operating condition.

Additionally, each employee has an Operator Qualification (OQ) Checklist that is completed and tracked in the OQ system. Operators are paired with other operators and work as trainees until they are deemed qualified on the piece of equipment and operation at the site. During the training period, they are exposed to station operations, responding to call outs with operators, station shutdowns, and purging and pressurizing stations. This training period lasts on average about one (1) year. A sample qualification checklist used to track employee training is attached.

j. Provide an explanation of why El Paso Natural Gas (EPNG) feels that the time necessary for compliance is too long when it is listed as 12 to 36 months? Are there plans to shut down all or portions of the facility? EPA guidance recommends a compliance time of up to five years from State Implementation Plan (SIP) approval.

In Section 3.2 of the November 1, 2019 submittal, EPNG states that the estimated time frame of 12 to 36 months. Not all engines would be able to be modified simultaneously as pressure must be maintained within the transmission pipeline at all times in order to meet our delivery obligations. EPNG concluded that the options presented are not cost effective but did not conclude that the time for compliance was too long.

There are no plans to shut down all or portions of the facility.

k. Please verify the waste generation and disposal and water consumption are considered in the cost analysis. If not, this should be included in the cost analysis.

Waste generation and disposal and water consumption are included in the cost analysis.

l. In Table 2, provide the basis for calculating the 2016 emissions inventory. For example, is this based on the emission limits and operating hours, or test data and operating hours?

The 2016 emissions inventory is based on the emission limits and operating hours of the engines.

m. Consider and include a discussion on the feasibility and cost of technology that limits engine capacity and reduce NOx emissions. Also evaluate limitations on engine operating hours or shutting down engines that are no longer needed to reduce emissions. Based on the emissions inventory for 2016, it appears that seven of the fourteen engines operated for very few hours during the year and other engines appear to have operated for only a portion of the year.

The compressor units at Blanco operate on a demand basis and full utilization of all of the units may be required at a given time. As such, EPNG is not able to limit operating hours. Because of the nature of storage and compression utilization on the EPNG lines, any operational restrictions could have the potential to have significant disruptions to operations on site as well as to our upstream and downstream customers.

n. *Consider and include a discussion on the feasibility of replacing natural-gas fueled engines with commercial electric powered compressors.*

The cost for replacing with electric compression can vary widely, depending on on-site conditions and the proximity to an existing high-voltage transmission line. A recent analysis for EPNG's Washington Ranch facility concluded replacement with electric compression would be approximately $2,676 per horsepower including additional electric utility line installation Using this assumption, replacement of the fourteen (14) 943-hp units at Blanco would cost approximately $35 million. Although a full four-factor analysis has not been performed for this replacement, this is cost prohibitive. No unit replacements are planned at this time.

o. *Please provide the electronic spreadsheets used for all cost analysis calculations.*

See attached spreadsheets.

If you have questions or need clarification, please contact me at (719) 520-3786 or via email at Travis_Ray@kindermorgan.com

Sincerely,
El Paso Natural Gas Company, L.L.C.

Travis Ray
EHS Specialist

Budgetary Estimate: HES-EH1213

HOERBIGER

Jon Goss
Kinder Morgan
Houston, Texas

September 20, 2019

Compression Technology

HOERBIGER Service North America Headquarters
3350 Gateway Drive
Pompano Beach, Florida 33069

Engineered Solutions
Houston, Texas

RE: Quote for optimization and emission retrofits for fourteen (14) GMV-10TF units located at the Blanco New Mexico Compressor Station.

Dear Mr. Goss,

HOERBIGER Engineering Services (HES) is pleased to respond to your request for a budgetary estimate concerning engine and compressor optimization retrofits for the Cooper GMV 10TF units located in Blanco New Mexico. This is a ***budgetary estimate*** for the scope of work listed in Section 1. Since no site visit has been made prior to this proposal, certain assumptions where made to be able to offer this estimate. It is not uncommon for final pricing to be within +/- 20% of this estimate after a site visit is conducted.

As a budgetary estimate, this proposal includes *all* of the expected materials and labor efforts required to meet the project guarantees. If the proposal, as written, fails to meet the guarantees, HES will bear the cost of any changes necessary to meet the requirements.

A detailed summary of this estimate can be found below within the Detailed Bid Description. HES reserves the right to correct clerical errors in this proposal. This proposal is valid for 90 days and acceptance is dependent upon reaching acceptable terms.

HES looks forward to the opportunity to work with Kinder Morgan on this project. If there are any questions concerning this estimate, please do not hesitate to call me at (512) 633-4001.

Sincerely,

Justin Spillman

_____

Justin Spillman
Solutions Specialist
HOERBIGER Engineered Solutions

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TECHNICAL DESCRIPTION

Customer currently has, in operation, fourteen (14) Cooper GMV-10TF units located at their Blanco, New Mexico Compressor Station. This station sits at an elevation of 5,605 ft above sea level and each unit is currently rated at 913 Hp for a station total of 12,782 Hp. The current emissions output for these units are between 12 – 15 g/bhp-hr for NOx and 1.4 g/bhp-hr for CO. The customer has requested solutions, pricing and options to reduce these limits to 5g, 3g and <1 g for NOx and not to exceed their baseline of 1.4 g/bhp-hr output for CO. After an Engineering review, HOERBIGER has put together the following options that will be needed to achieve the customer requests. To achieve the 5 g/bhp-hr or 3 g/bhp-hr emissions limits, the required technology is the same which will give the customer the potential savings and flexibility when considering other engine upgrades. At these levels, we will be able to meet or exceed the NOx requirement and avoid a negative impact on CO which will eliminate those associated expenses.

OPTION 1 - $784,014 per unit

Skid Mounted VFD Electric motor driven blower with Aftercooler
***HyperFuel*™ System**
Engine auxiliary cooling system

If the customer elects to achieve NOx levels of 1 g/bhp-hr or lower, on these units, additional technology will be needed to address the rise in baseline CO.

OPTION 2 - $1,624,286 per unit

Skid Mounted VFD Electric motor driven blower with Aftercooler
***HyperFuel*™ System**
Engine auxiliary cooling system
Wet to Dry Manifold Conversion
Muffler with Oxidation Catalyst
Cylinder Heads with PCC

In addition to the two options listed above, a third option has been discussed which would include uprating 9 units at this station and retiring the remaining 5. In order to maintain the overall station HP level of 12,782 each unit will be uprated to 1,463 Hp.

OPTION 3 - $1,334,282 per unit

Turbocharger
***HyperFuel*™ System**
Compressor Cylinder Upgrade
Power Cylinder Upgrade

1. Detailed Bid Description

HES agrees to provide the customer, Kinder Morgan, with all of the equipment, engineering, installation, and documentation necessary to perform engine and compressor optimization/emissions retrofits for the GMV-10TF at the Blanco New Mexico Compressor Station. This estimate includes the following parts and services but not limited to:

1.1 HES Scope of Work

This bid is provided as a fixed price "turn-key" bid, it includes the following parts and services:

1.1.1. All design and project engineering required for unit specific adaptation and installation of the following systems:
- 1.1.1.1. VFD Electric motor driven blower with Aftercooler
- 1.1.1.2. PCC Ignition System
- 1.1.1.3. *ePCC*™ System
- 1.1.1.4. *HyperFuel*™ System
- 1.1.1.5. Exhaust system
- 1.1.1.6. Dry exhaust manifold
- 1.1.1.7. Engine auxiliary cooling system

1.1.2. All manpower necessary to remove the replaced systems and install the new systems listed in section 1.1.1.

1.1.3. All commissioning and start up services.

1.1.4. All drawings necessary to document modifications and support the installation.

1.1.5. Training for maintenance and operations of the installed systems.

1.1.6. Disposal of removed/retired equipment and HES refuse.

1.2. HES Scope of Supply (On-engine)

HES will supply ALL of the components necessary to complete the installation of the systems listed in section 1.1 above. Following is a list of the primary components of the installed systems. It is not a comprehensive list and does not relieve HES of the obligation to supply unnamed but necessary components.

1.2.1. Electric Motor Driven Blower (Skid Mounted)
- 1.2.1.1. Inlet filter
- 1.2.1.2. Isolation valve
- 1.2.1.3. Check valve
- 1.2.1.4. Blow off silencer
- 1.2.1.5. Blow off valve
- 1.2.1.6. Coupling and guard
- 1.2.1.7. Expansion joint
- 1.2.1.8. Spool pieces
- 1.2.1.9. VFD motor
- 1.2.1.10. 6 stage blower
- 1.2.1.11. Structural base
- 1.2.1.12. Disconnect and/or motor starter

1.2.2. Aftercooler

1.2.2.1. Aftercooler heat exchanger core
1.2.2.2. Aftercooler inlet transitions
1.2.2.3. Aftercooler outlet transitions
1.2.2.4. New 3-way control valve and transitions for AMT control
1.2.2.5. Aftercooler flexible pipe joints
1.2.2.6. Aftercooler inlet automatic air bleeder valve
1.2.2.7. Aftercooler outlet automatic air bleeder valve
1.2.2.8. Aftercooler water inlet/outlet thermowell
1.2.2.9. Aftercooler water inlet/outlet temperature gauge
1.2.2.10. Aftercooler outlet pressure gauge
1.2.2.11. Fittings, flanges, bolts and gaskets for all piping
1.2.2.12. Cooling water inlet and outlet piping modifications

1.2.3. Ignition System (PCC)
1.2.3.1. One Cooper pre-chamber per cylinder or Eco-Jet System
1.2.3.2. One Modified Head (Not Eco-Jet System)
1.2.3.3. All bolts, Gaskets and washers to support installation (Not Eco-Jet System)
1.2.3.4. (For Eco-Jet) One Cooper EcoJet™ pre-chamber per cylinder
1.2.3.5. Coolant Pump (1.5HP, 3Φ, Explosion Proof)
1.2.3.6. Water filter
1.2.3.7. Spark plugs
1.2.3.8. Conduit, wiring, fittings and tubing

1.2.4. The *ePCC* System is a Class I, Division 2, Group D system and is installed according to those guidelines and it includes the following major components:
1.2.4.1. One *ePCC* Controller and HMI for each engine
1.2.4.2. One 110 VAC to 24 VDC power supply for each engine
1.2.4.3. One *ePCC* valve for each PCC
1.2.4.4. One fuel hose for each *ePCC*
1.2.4.5. All necessary tubing and fittings
1.2.4.6. All necessary conduit, wire and fittings

1.2.5. The *HyperFuel* Valve™ System is a Class I, Division 2, Group D system and is installed according to those guidelines and it includes the following major components:
1.2.5.1. One *HyperFuel Valve* for each cylinder
1.2.5.2. One *HyperFuel Valve* Control System for each engine
1.2.5.3. Fuel manifold
1.2.5.4. Excess flow safety valve
1.2.5.5. Pneumatically operated block and bleed valves
1.2.5.6. Unit level fuel filtration
1.2.5.7. Filter DP gauge
1.2.5.8. Unit level fuel pressure regulation
1.2.5.9. 110 Volt AC to 24 DC Volt power supply
1.2.5.10. Magnetic pickups
1.2.5.11. All necessary conduit, wire and fittings
1.2.5.12. All necessary tubing, hoses and fittings

1.2.6. Dry Exhaust Manifold
1.2.6.1. Segmented exhaust manifold

1.2.6.2. Water header
1.2.6.3. Transition outlet spool

1.3. HES Scope of Supply (Off-engine)

1.3.1. Exhaust system
1.3.1.1. Silencer/catalyst combination
1.3.1.2. Removable oxidation catalyst
1.3.1.3. Backfire relief valve
1.3.1.4. Insulation blankets
1.3.1.5. Tail pipe strakes
1.3.1.6. Exhaust pipes and transitions
1.3.1.7. Coating
1.3.2. Engine auxiliary cooling system
1.3.2.1. Air cooled heat exchanger
1.3.2.2. Expansion tank
1.3.2.3. 3 way control valve
1.3.2.4. Valves, pipes and fittings

1.4. Customer Scope of Supply

1.4.1. Unit Fuel Gas System to within 30' of engine (Conditioned and Heated)
1.4.1.1. Metered and Conditioned Fuel Gas to within 30 ft of unit. Provide 1" female NPT port ball valve for HES to connect. Pressure to be regulated to a minimum of 550 (psig)
1.4.1.2. The fuel gas measurement end devices for each unit will require an accuracy of ±1% with a flow rate update frequency of at least 1 Hertz.
1.4.1.3. Filtered to remove 99% of all particles and liquids greater than 1 micron.
1.4.1.4. HES recommends that the fuel gas be heated to a temperature above the highest ambient dew point (~100 °F) to prevent the formation of condensation on the fuel gas piping.
1.4.2. Fuel Gas Custody Transfer Metering and Reporting.
1.4.3. Supply all electrical requirements to station (MCC).
1.4.4. Engine operator to start, stop and operate the unit as necessary for testing and commissioning.
1.4.5. Environmental permitting.
1.4.6. Removal and disposal of Spectra Energy hazardous materials
1.4.6.1. Provide penetrations in transite siding and dispose of hazardous waste if required. At this point in the design phase HES does not expect to disturb any of the existing transite siding.
1.4.7. NDE testing and construction inspection as required.
1.4.8. Bring chromatograph from station to panel.
1.4.9. Supply necessary documentation to HES for engineering and automation changes.
1.4.10. Piping and Installation of the Exhaust system
1.4.11. Piping and Installation of the Aux Cooling system
1.4.12. Installation of pad for the Blower Package skid
1.4.13. Automation systems, hardware or programming required to support these upgrades

1.4.14. Customer will allow HES and it's subcontractors to use plant facilities for accumulation of parts.
1.4.15. The customer will make repairs to the unit or its support equipment if the equipment is not operating as designed.
1.4.15.1. Repair service may be requested of HES. Repairs will be quoted and billed on a time and material basis.
1.4.16. Supply Noise attenuation requirements.
1.4.17. Provide a chromatograph reading at the station.
1.4.18. Provide space for HES office trailers, restrooms, and connex buildings for the duration of the project.

2. Clarifications and Exceptions to HES Proposal

The following items have been identified as Exceptions to the project.

2.1.1. Time spent waiting by HES personnel or its sub-contractors due to delays caused by station problems or station non-preparedness are not included in the base proposal. Should such delays be encountered, HES shall be compensated in accordance with the attached rate sheets and schedule shall be extended by the length of the delay. Additional waiting time will be billed on a time and materials basis.
2.1.2. Price does not include any applicable sales, use, or other regulatory taxes. Such taxes will be calculated and billed at the time of HES invoicing.
2.1.3. Price does not include unit panel , unit panel programming or communication connects to the customer's Station PLC. This can be quoted separately upon request.

3. At Risk Items

The following items have been identified as marginally suitable (at risk) for the project. HES agrees to try and incorporate the existing items into the proposed upgrade to reduce the project cost. However, HES makes no guarantee as to the successful use of the identified items. If the at risk items prove unsuitable at the time of commissioning, the customer will be responsible for paying the cost of replacing the at risk item with components that are suitable for the application.

3.1. The following items are identified as "at risk" for this project:

3.1.1. No identified at risk items at this stage.

4. Minimum Unit Health and Performance Assumptions

4.1. Current Unit Condition

The following assumptions were made during preparation of this budgetary estimate. HES scope will have to be added to the project or the customer scope of supply will be amended if any of the assumptions are not valid.

4.1.1. Current unit hardware and configuration is meeting current emissions requirements.
4.1.2. Units have CPU-2000 or other flywheel referenced ignition system
4.1.3. Unit is in good health, with no mechanical defects.
4.1.4. The compressor building is rated Class I, Division 2, Group D.

4.1.5. Current unit valves and related limit switches are functioning properly.
4.1.6. Gas analysis with periodic updates

5. Compliance Statement and Exceptions to Bid Request

At the completion of this proposal HES has not identified exceptions to the Bid Request.

6. Proposed Installation Schedule

HOERBIGER will work with Kinder Morgan on an acceptable project schedule

7. Project Guarantees and General Warrantees

7.1. Performance Guarantees - TBD

HES guarantees that the addition of the equipment listed in section 1. Detail Bid Description will allow the unit to operate with the following brake specific emissions mass rates.

7.1.1. Emissions

NOx	Options given for 5 g/bhp-hr, 3 g/bhp-hr and < 1 g/bhp-hr
CO	Not to exceed baseline of 1.4 g/bhp-hr

7.2. Warranties

7.2.1. The standard manufacturer's warranties for all third party components are in place at the time of shipment.
7.2.2. The standard warranty for *ePCC* system (Valves and Controller) is 24 months, beginning at the start of commissioning.
7.2.3. The standard warranty for the *HyperFuel* Valve is 12 months, beginning at the start of commissioning.
7.2.4. The standard warranty for the *HyperFuel* Valve System Controller is 24 months, beginning at the start of commissioning.
7.2.5. Any exceptions to these warranties are noted on the cover page.

8. Payment and Invoicing Conditions

HES will invoice the customer directly for all work done in support of the project. HES contractors will invoice HES only, and will not submit invoices directly to the customer.

8.1. Project Invoicing

Invoicing will be agreed upon and detailed in the contract.

8.2. Cancellation

The Customer shall notify HES in writing at least twenty-four (24) hours in advance of termination. The Customer shall compensate HES for all documented costs if the Customer cancels the order. These costs include, but are not limited to, parts, engineering, shipping, down payments, restocking charges, labor and travel expenses.

8.3. Payment Terms

All HES invoices will be for the full amount owed. If the customer has a policy of retaining a percentage of contract price pending completion, the customer will be responsible for calculating the retainage. All retained monies are to be released within 30 days of final acceptance, not to exceed 60 days after completion of commissioning.

Retainages in excess of 10% are generally unacceptable to HES. Withholding in excess of 10% must be agreed to in writing at the time of contract execution.

8.3.1. All invoices are to be paid within 30 days from date of invoice.

9. Indemnification and Limits of Liability (Will be identified in contract)

10. Codes and Standards

All work shall be installed and tested in accordance with all applicable sections of the latest edition of the following codes and standards. Differences in company and code requirements could result in added charges:

NEC (NFPA 70)	National Electric Code
CFR Title 49, Part 192	Minimum Safety Standards for Gas Lines
ANSI 2223.1	National Fuel Gas Code
API 1104	Welding of Pipelines and Related Facilities
ANSI B31.8	Gas Transmission and Distribution Piping Systems
ANSI B31.3	Process Piping Systems
ANSI B16.5	Pipe Flanges and Flange Fittings
ASME Sections VIII & IX	Boiler and Pressure Vessel Code

OPERATOR QUALIFICATION
Appendix G
COVERED TASK ASSIGNMENTS - GAS
Revised 3/23/2017

Employee Name:	EE Number:	Date:
Supervisor's Name:	Region/Location:	
Date Discussed with Employee:	***Supervisor's Signature***	

Submit this form with assigned covered tasks checked in the *Yes* column to your Regional OQ Coordinator.

CT #	Covered Task Title	Yes
01.01.01	Abnormal Operating Conditions	☐
02.01.01	Gas Detection & Alarm System Maintenance & Performance Test	☐
02.02.01	Isolation of Compressor Units	☐
02.03.01	Compressor Station Inspection & Testing of Remote Control Shutdown Devices	☐
03.01.01	Operating Compressor Units: Remote	☐
03.01.02	Operating Compressor Units: Manual	☐
03.02.01	Shutting Down Compressor Units: Remote	☐
03.02.02	Shutting Down Compressor Units: Manual	☐
03.03.01	Starting Compressor Units: Remote	☐
03.03.02	Starting Compressor Units: Manual	☐
04.01.01	Measure Damage on Installed Pipe and Components	☐
04.01.02	Corrosion Monitoring – Atmospheric, External, and Internal: Offshore Pipelines	☐
04.01.03	Visual Inspection of Buried Pipe and Components When Exposed	☐
04.01.04	Visual Inspection of Internal Surface of Pipe	☐
04.01.05	Visual Inspection for External/Atmospheric Corrosion (effective 6/30/17)	☐
04.01.06	Insert and Remove Coupons/Probes for Internal Corrosion Monitoring	☐
04.01.07	Nondestructive Testing – Magnetic Particle Testing of Pipe	☐
04.02.01	Coating Maintenance /Application and Repair – Sprayed, Brushed, or Rolled	☐
04.02.02	Coating Maintenance/Repair – Wrapped	☐

CT #	Covered Task Title	Yes
05.01.01	Cathodic Protection System Maintenance: Rectifiers	☐
05.01.02	Cathodic Protection System Maintenance: Electrical Isolation	☐
05.01.03	Cathodic Protection System Maintenance: Anodes, Anode Ground Beds, & AC Voltage Mitigation (task name change)	☐
05.01.04	Inspect or Test Cathodic Protection Bonds (task name change)	☐
05.01.05	Cathodic Protection System Maintenance: Reverse Current Switches	☐
05.01.06	Cathodic Protection System Maintenance: Automatic Potential Controlled Protection Systems	☐
05.01.07	Cathodic Protection System Maintenance: AC Voltage Mitigation System	☐
05.01.08	Cathodic Protection: Read Rectifier (effective 5/1/17)	☐
05.02.01	Cathodic Protection Systems – Electrical Connections	☐
05.03.01	Cathodic Protection System Testing: Test Stations	☐
05.03.02	Cathodic Protection System Testing: Pipe to Soil	☐
06.01.01	Indirect Inspection: Close Interval Survey	☐
06.01.02	Indirect Inspection: Direct Current Voltage Gradient (DCVG) Survey	☐
06.01.03	Indirect Inspection: Voltage Gradient (ACVG) Survey	☐
06.01.04	Indirect Inspection: AC Current Attenuation (ACCA or PCM) Survey	☐
07.01.01	Locating, Installing & Protecting Customer Meters & Regulators: Residential & Small Commercial	☐
07.01.02	Locating, Installing & Protecting Customer Meters & Regulators: Large Commercial	☐
07.02.01	Customer Pressure Regulating, Limiting & Relief Device: Residential & Small Commercial	☐
07.02.02	Customer Pressure Regulating, Limiting & Relief Device: Large Commercial & Industrial	☐
08.01.01	Locating Pipelines	☐
08.02.01	Damage Prevention During Excavation Activities	☐
09.01.01	System Patrolling	☐
10.01.01	Plastic Pipe – Electrofusion: Couplings	☐
10.01.02	Plastic Pipe – Electrofusion: Sidewall	☐
10.02.01	Plastic Pipe – Butt Heat Fusion	☐
10.03.01	Plastic Pipe – Sidewall Heat Fusion	☐
10.04.01	Mechanical Joints: Stab Fittings	☐

CT #	Covered Task Title	Yes
10.04.02	Mechanical Joints: Compression Couplings 2” & Less	☐
10.04.03	Mechanical Joints: Compression Couplings Greater Than 2”	☐
10.05.01	Joining of Pipe - Flange Assembly	☐
10.05.02	Joining of Pipe/Tubing – Threaded Fittings	☐
10.07.01	Solvent Cement Joints	☐
11.01.01	Direct/Inspect In-service Pipeline Lowering	☐
11.02.01	Detect/Inhibit/Mitigate Pipeline Hydrate Formation in Pipeline	☐
12.01.01	Leakage Survey: Walking	☐
12.01.02	Leakage Survey: Mobile	☐
12.02.01	Outside Leakage Investigation, Pinpointing and Grading	☐
12.03.01	Inside Gas Leakage Investigation	☐
13.01.01	Leak & Strength Test – Service Lines, Mains & Transmission Lines: Gaseous: Test Pressures < = 100 psi	☐
13.01.02	Leak & Strength Test – Service Lines, Mains & Transmission Lines: Gaseous: Test Pressures $\geq$ 100 psi	☐
13.01.03	Leak & Strength Test – Service Lines, Mains & Transmission Lines: Hydrostatic Test	☐
13.01.04	Leak & Strength Test – Service Lines, Mains & Transmission Lines: Test at Operation Pressure	☐
14.01.01	Abandonment or Inactivation of Facilities	☐
14.02.01	Backfilling	☐
14.03.01	Installation of Steel Pipe – Field Bends	☐
14.04.01	Casing Vents and Seals	☐
14.05.01	Underground Clearances	☐
14.06.01	Installation of Plastic Pipe: Direct Burial	☐
14.06.02	Installation of Plastic Pipe: Boring	☐
14.06.03	Installation of Plastic Pipe: Plowing/Planting	☐
14.06.04	Installation of Plastic Pipe: Plowing/Pull-In	☐
14.06.05	Installation of Plastic Pipe: Above Ground	☐
14.06.06	Installation of Plastic Pipe: Insertion	☐
14.07.01	Installation of Steel Pipe: Direct Burial	☐
14.07.02	Installation of Steel Pipe: Boring	☐
14.07.03	Installation of Steel Pipe: Plowing/Pull-In	☐
14.07.04	Installation of Steel Pipe: Above Ground	☐

CT #	Covered Task Title	Yes
14.07.05	Installation of Steel Pipe: Insertion	☐
14.08.01	Cover – Service Lines, Mains & Transmission Lines	☐
14.08.02	Cover – Offshore Pipelines	☐
14.09.01	Inspection: Compliance with Procedures & Standards	☐
14.09.02	Inspection: Inspection of Materials	☐
14.10.01	Line Markers	☐
14.11.02	Pipeline Shutdown, Startup or Pressure Change: Stopple Fitting	☐
14.11.03	Pipeline Shutdown, Startup or Pressure Change: Operating Identified Valve(s)	☐
14.11.04	Pipeline Shutdown, Startup or Pressure Change: Method(s) Required for Other Pipe Materials	☐
14.11.05	Launching and Receiving Internal Devices	☐
14.12.01	Protection from Hazards	☐
14.13.01	Protection When Minimum Cover Not Met	☐
14.14.01	Purging: Large Volume, i.e. Segment of Main or Transmission Line, etc.	☐
14.14.02	Purging: Small Volume, i.e. Service Line, Short Pipeline Segments, Compressor, Component, etc.	☐
14.15.01	Uprating: Reinforce or Anchor Offsets, Bends and Dead Ends – Longitudinal Straps	☐
14.15.02	Uprating: Reinforce or Anchor Offsets, Bends and Dead Ends – Anchoring & Buttressing	☐
14.16.01	Installation of Steel Pipe – Repair of Imperfections or Damage: Grinding	☐
14.18.01	Support, Expansion Joint and Anchor Maintenance – Exposed Pipeline	☐
14.19.01	Tapping Steel and Plastic Pipe: Manual (Self-Tapping)	☐
14.19.02	Tapping Steel and Plastic Pipe: Mechanical Tapping Equipment	☐
14.20.01	DOT Inspection of Valves	☐
14.20.02	Repair Valves	☐
14.21.01	Segment Removal	☐
14.22.01	Leak Clamps & Sleeves: Bolt-On Type	☐
14.22.02	Leak Clamps & Sleeves: Composite Sleeve (Clock Spring)	☐
15.01.01	Odorization – Mains & Transmission Lines: Periodic Sampling	☐
15.01.02	Odorization – Mains & Transmission Lines: Odorizer Maintenance	☐
16.01.01	Gas Quality: Operate/Test/Maintain Carbon Dioxide (CO2) Analyzers	☐
16.01.02	Gas Quality: Maintain/Service Chromatographs	☐
16.01.03	Gas Quality: Operate/Test/Maintain Oxygen (O2) Analyzers	☐
16.01.04	Gas Quality: Operate/Test/Maintain Sulfur Analyzers	☐

CT #	Covered Task Title	Yes
16.01.05	Gas Quality: Operate/Test/Maintain Moisture Analyzers	☐
16.01.07	Gas Quality: Operate & Maintain Gas Samplers	☐
16.01.08	Gas Quality: Troubleshoot/Repair Chromatographs	☐
16.01.09	Gas Quality: Troubleshoot & Repair Sulfur Analyzers	☐
16.01.10	Gas Quality: Troubleshoot/Repair Moisture Analyzers	☐
16.01.11	Gas Quality: Troubleshoot/Repair Carbon Dioxide (CO2) Analyzers	☐
16.01.12	Gas Quality: Troubleshoot/Repair Oxygen (O2) Analyzers	☐
18.01.01	Overpressure Safety Devices – Inspect, Test, and Calibrate Relief Valves	☐
18.01.02	Pressure Limiting Devices – Inspect, Test and Calibrate	☐
18.02.01	Vault Maintenance	☐
20.01.01	Service Line Replacement	☐
20.01.02	Service Line Replacement: Underground Service Entrance (Prerequisite 20.01.01)	☐
20.03.01	Service Lines Not in Use and Service Discontinuance	☐
24.01.01	Welding Process	☐
24.02.01	Visual Inspection of Welds	☐
24.03.01	Nondestructive Testing of Welds	☐
24.04.01	Miter Joints	☐
25.01.01	Dehydration: Operate/Maintain Liquid Knock-out	☐
25.01.02	Dehydration: Maintain/Repair Gas Fired Dehydration System Controls	☐
25.01.03	Dehydration: Operate/Maintain Gas Dehydration System	☐
25.01.04	Dehydration: Start-up/Shutdown of Dehydration System	☐
25.01.05	Dehydration: Troubleshoot/Repair Gas Dehydration System	☐
25.01.06	Gas Treatment: Read/Verify/Maintain Operating Parameters for Gas Processing/Amine System	☐
25.01.07	Gas Treatment: Troubleshoot/Correct Gas Processing/Amine System	☐
25.01.08	Dehydration: Maintain/Repair Gas Fired Mole Sieve Dehydration System Controls	☐
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25.01.10	Dehydration: Start-up/Shutdown of Mole Sieve Dehydration System	☐
25.01.11	Dehydration: Troubleshoot/Repair Mole Sieve Dehydration System	☐
27.01.01	Gas Control	☐

El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

June 5, 2023 **FED EX 3992 0707 9199**

Ms. Kirby Sue Olson, Ph.D.
Planning Section Chief
Air Quality Bureau
New Mexico Environment Department
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

Re: EPNG's Blanco A Compressor Station Regional Haze Four Factor Analysis, Revised

Dear Ms. Olson:

El Paso Natural Gas Company, L.L.C. (EPNG) is submitting the enclosed revised Regional Haze Four Factor Analysis (4FA) for the Blanco A Compressor Station. This analysis replaces, in its entirety, the 4FA that was submitted by EPNG on or about November 1, 2019. EPNG appreciates the opportunity to correct deficiencies mutually identified in the original document.

As we discussed during our meeting on May 3, 2023, EPNG has recently submitted an Alternate Emission Standard (AES) Plan and is about to submit an Alternative Compliance Plan (ACP) in accordance with the New Mexico Ozone Precursor Rule 20.2.50 NMAC (Ozone Rule). The ACP in particular addresses the units at Blanco A that are analyzed in the enclosed 4FA. EPNG notes that the timeframe for action under the Ozone Rule is significantly sooner than under the Regional Haze Rule. As such, decisions made by NMED for implementation of the Ozone Rule could significantly alter the facts upon which the enclosed 4FA analysis is based.

Additionally, as we previously discussed, EPNG is concerned that different decisions may be reached under each of the two rules. To this end, and to the extent that controls or limitations may be required under either the Ozone Rule or the Regional Haze Rule, EPNG desires to be actively and continuously engaged with the pertinent New Mexico Environment Department review groups as the reviews progress under both rules.

If you have any questions on any of this information, please contact me at 713.420.3463 or at tom_mitchell@kindermorgan.com.

Sincerely,

R. Thomas Mitchell

Digitally signed by R. Thomas Mitchell
DN: cn=R. Thomas Mitchell, o=Kinder Morgan, ou, email=tom_mitchell@kindermorgan.com, c=US
Date: 2023.06.05 15:25:15 -05'00'

R. Thomas Mitchell
Manager, Air Permitting & Compliance
El Paso Natural Gas Company, L.L.C.

Enclosure

El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

Regional Haze Four-Factor Analysis

El Paso Natural Gas Company, L.L.C.
Blanco A Compressor Station
San Juan County, New Mexico

October 2019

Revision June 2023

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1. EXECUTIVE SUMMARY

The Blanco A Compressor Station (Blanco A), owned and operated by El Paso Natural Gas Company, L.L.C. (EPNG), is located near Bloomfield in San Juan County, New Mexico. Blanco A is a natural gas compressor station that compresses natural gas for the purpose of transportation to a local distribution company, an industrial facility or another transportation pipeline.

The New Mexico Environmental Department (NMED) has requested a report containing a complete Four-Factor Analysis (4FA) for the Blanco A under the Regional Haze requirements of the Clean Air Act. The analysis has identified possible NOx control options for 14 reciprocating internal combustion engines operating at the Blanco A using the Western Regional Air Partnership (WRAP) assessment protocol by assessing the following four factors:

- Cost of the control;
- Time necessary to install the control;
- Energy and non-air quality impacts of the control; and
- The remaining useful life of the emission point.

The evaluation concluded that:

- Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) are technologically infeasible.
- Low Emission Combustion (LEC) Retrofit is economically infeasible with a cost effectiveness ranging from $18,356 to $97,332,475 depending on the LEC option and engine.
- Good Combustion Practices (GCP) are technically and economically feasible and constitute Best Available Retrofit Technology (BART).

EPNG notes that GCP is already employed for the subject engines.

However, as noted in the report, there is overlap between the New Mexico Ozone Precursor Rule 20.2.50 NMAC and the Regional Haze Rule. Although not required under either rule, EPNG proposes that NMED allow EPNG to retire seven units at Blanco A if, an only if, the retirement is approved as a compliance strategy under both regulations and by FERC. Importantly, this solution would allow EPNG to decrease NOx emissions in a manner that allows it to meet its FERC obligations (subject to FERC approval). While not economically feasible as defined by the Regional Haze Rule, this solution is lower cost than other more-costly or technically infeasible NOx-reduction options. Accordingly, EPNG requests that NMED consider this environmentally advantageous solution under both rules even though it is not mandated by either rule.

2. BACKGROUND INFORMATION

In the 1977 amendments to the Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across the United States, known as Federal Class I areas. The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

(1) *Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A)*

This is known as a four-factor analysis.

(2) *Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B).*

The uniform rate of progress or improvement is sometimes referred to as the glidepath and is part of the state's Long Term Strategy (LTS).

The second implementation planning period (2018-2028) for national regional haze efforts is currently underway. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural or biogenic and manmade or anthropogenic sources of emissions. Using a Photochemical Grid Model (PGM), the Western Region Air Partnership (WRAP), in coordination with the EPA, is tasked with comparing anthropogenic source contributions against natural background concentrations.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this, the NMED reviewed 2016 emission inventory data for major sources and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I area. From this analysis, 24 facilities were identified by the NMED. On July 18, 2019 the NMED informed EPNG that the Blanco A was identified as one of the sources contributing to regional haze at the nearest Mesa Verde National Park Class I area. On 1 November 2019, EPNG provided its initial analysis to NMED. This report replaces that 1 November 2019 submission.

In coordination with WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. In the NMED's July 18, 2019 notification letter to EPNG, it specifies that any single piece of equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and/or 5 tons

per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The equipment at Blanco A subject to the 4FA is summarized in Table 1. Because SO_2 emissions from the 14 reciprocating engines at Blanco A Compressor Station are less than the 10 lb/hr threshold, NOx is the only pollutant subject to evaluation in this four-factor analysis.

Table 1. EPNG Blanco A – RH Second Planning Period 4FA – Subject Sources

Equipment Type	Max Capacity*	NMED Unit No.	Make Model	Construction Date
2SLB Reciprocating Engine	943 HP	A-01	Cooper Bessemer, GMV10-TF	8/1/1953
2SLB Reciprocating Engine	943 HP	A-02	Cooper Bessemer, GMV10-TF	8/1/1953
2SLB Reciprocating Engine	943 HP	A-03	Cooper Bessemer, GMV10-TF	8/1/1953
2SLB Reciprocating Engine	943 HP	A-04	Cooper Bessemer, GMV10-TF	8/1/1953
2SLB Reciprocating Engine	943 HP	A-05	Cooper Bessemer, GMV10-TF	8/1/1953
2SLB Reciprocating Engine	943 HP	A-06	Cooper Bessemer, GMV10-TF	8/1/1953
2SLB Reciprocating Engine	943 HP	A-07	Cooper Bessemer, GMV10-TF	8/1/1953
2SLB Reciprocating Engine	943 HP	A-08	Cooper Bessemer, GMV10-TF	8/1/1953
2SLB Reciprocating Engine	943 HP	A-09	Cooper Bessemer, GMV10-TF	8/1/1953
2SLB Reciprocating Engine	943 HP	A-10	Cooper Bessemer, GMV10-TF	8/1/1953
2SLB Reciprocating Engine	943 HP	A-11	Cooper Bessemer, GMV10-TF	8/1/1953
2SLB Reciprocating Engine	943 HP	A-12	Cooper Bessemer, GMV10-TF	8/1/1953
2SLB Reciprocating Engine	943 HP	A-13	Cooper Bessemer, GMV10-TF	8/1/1953
2SLB Reciprocating Engine	943 HP	A-14	Cooper Bessemer, GMV10-TF	8/1/1953

*The site rating for each engine is 913 HP at the site elevation of 5,605 ft above sea level.

Once the applicability of equipment and pollutants has been determined, potential retrofit control technologies must be identified. In accordance with 40 CFR 51 Appendix Y and at the recommendation of the NMED,[1] this is primarily achieved by utilizing the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) data. In order to determine the most relevant and current retrofit controls available, the RBLC is queried for the previous ten years. A summary of identified available retrofit controls along with a technical feasibility assessment for each control is provided in Section 3. The four-factor analysis is then conducted for those controls that are technically feasible.

[1] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

3.1. TWO-STROKE LEAN-BURN ENGINES

The Blanco A Compressor Station compresses natural gas for the purpose of transportation to a local distribution company, an industrial facility or another transportation pipeline. Emission sources located at the Blanco A Compressor Station include 14 natural gas-fired two-stroke lean-burn (2SLB) reciprocating internal combustion engines (RICE), all of which are subject to this four-factor analysis. The two-stroke design completes the power cycle in a single revolution of the crankshaft. NO_X is formed in reciprocating engines via three mechanisms:

(1) Thermal NO_X - the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion,
(2) Fuel NO_X - the evolution and reaction of fuel-bound nitrogen compounds with oxygen, and
(3) Prompt NO_X - the early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The Blanco A reciprocating engines use pipeline quality natural gas fuel, which contains a negligible amount of nitrogen compounds. Therefore, the formation of prompt and fuel NO_X will be insignificant. This analysis will focus on thermal NO_X. The rate of NO_X formation through the thermal NO_X mechanism is highly dependent upon the air-to-fuel ratio, combustion temperature, and residence time at the combustion temperature. Maximum thermal NO_X formation occurs near the stoichiometric air-to-fuel mixture ratio because combustion temperatures are greatest at this ratio.[2] Lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1), with exhaust oxygen levels of 12 % or more.[3]

NO_X reduction in natural gas-fired RICE can be accomplished by three general methods, as follows:

(1) Operational control methods, such as adjusting the timing or other operating parameters.
(2) Combustion control techniques, for example reducing the peak flame temperature by introducing inserts that limit initial NO_X formation.
(3) Post-combustion NO_X control technologies, which employ various strategies to chemically reduce NO_X.

3.2. POTENTIAL NOX CONTROLS FOR 2SLB ENGINES

To identify all feasible control technologies, the RBLC database, WRAP guidance, as well as available technical literature was reviewed. Using these sources, potentially applicable NOx control technologies for 2SLB engines were identified and are summarized in Table 2. A detailed description and discussion of the technical feasibility and anticipated performance of each control are provided below.

[2] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
[3] "Emission Control Technology for Stationary Internal Combustion Engines," Manufacturers of Emission Controls Association, 2015

Table 2. Potential Control Options for 2SLB RICE

Control Equipment	Technically Feasible	NO_X Control Efficiency
Selective Catalytic Reduction	**No**	**N/A**
Low Emission Combustion	**Yes**	**27% - 82%**
Good Combustion Practices and Fuel Selection	**Yes**	**Base Case**
Reduce Capacity and/or Operating Hours	**No**	**N/A**
Selective Non-Catalytic Reduction	**No**	**N/A**

3.2.1. Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust stream of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[4] The chemical reactions for this process are shown in the equations below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

An SCR system includes the catalyst, reagent storage tank, reagent injector, reagent pump, pressure regulator, and electronic controls to accurately meter the quantity of reagent injected as a function of engine load, speed, temperature, and NOx emissions to be achieved. The lifespan of the catalyst is primarily determined by the erosion caused by the flue gas, deactivation caused by ammonium bisulfate (NH_4HSO_4) poisoning, as well as the build-up and fouling by the catalyst.

The characteristic exhaust temperature for 2SLB engines shows higher excess O_2 in the exhaust stack. For 2SLB engines, with typical exhaust O_2 from 14 to 16% (depending on make, model and operating condition), typical exhaust temperature is in the range of 450 to 600°F. Exhaust temperature is a critical design parameter for SCR performance, and accordingly, the catalyst material is selected based on the design temperature of the exhaust. Based on current technology and practices, SCR's optimal exhaust temperature is between 600 - 850°F for base-metal catalyst and 750 – 1100°F for zeolite catalysts. Therefore, SCR's use as a control technology is limited to sources where the exhaust temperature is within those ranges.

Precious metal catalyst may perform at temperatures below 450°F, however complications such as reagent decomposition, reagent slip, catalyst contamination due to unreacted reagent (salt formation), etc. may arise. Temperatures below the desired range reduce the reduction efficiency – i.e., increase NO_X and ammonia emissions.

At higher temperatures, ammonia may "slip," meaning that a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. Unreacted reagent in the exhaust can form ammonium sulfates, which may plug or corrode downstream equipment, and/or catalyst damage may

[4] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

occur. Streams carrying large amounts of ammonium sulfates may blind the catalyst and may necessitate the application of a soot blower.

When compared to the typical 450 – 600°F temperature range for 2SLB engines, no single catalyst material offers high, stable performance across that range. Thus, even if other SCR technical issues (e.g., associated with reagent control) are addressed, current catalysts are not adequate to ensure stable, high-level performance for 2SLB engines.

In addition to the temperature issues, use of an aqueous reagent is common for engine applications. The water associated with aqueous urea (or ammonia) injection for an engine with higher NO_X emissions (e.g., NO_X is not controlled) could decrease exhaust temperature by 5 to 20 °F. This further complicates system engineering and catalyst material requirements.

For engines that typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia injection to gain the reductions needed.[5] In the case of the Blanco A, the 14 reciprocating engines run at ongoing variable loads.

Finally, there has been no application of SCR on this model of Cooper Bessemer engines (see attached RBLC results). A thorough twenty-year review of the RBLC tables was conducted and there were no examples of an SCR being used as a control for 2SLB engines at this time. The lack of availability or comparable use of an SCR on these Cooper Bessemer engines presents the case that this control technology is considered technically infeasible. Consequently, SCR is not evaluated further in this four-factor analysis.

3.2.2. Low Emission Combustion (LEC) Retrofit

LEC retrofit, including the Cooper Bessemer trademark name Clean Burn Technology (CBT), is another term for utilizing combustion mixtures in engines with fuel-lean air-to-fuel ratios. This method of reducing NO_X emissions involves reconfiguring the engines by adding or enhancing an air-to-fuel ratio controller, making the unit capable of operating at optimal air-to-fuel ratios.

As described in Section 3.1 of this report, lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1). A combustion mixture with a higher air-to-fuel ratio results in reduced NO_X emissions because fuel-lean mixtures lowers the combustion temperature by diluting energy input. There is a tradeoff between air-fuel ratio and heat rate; higher air-to-fuel ratio in lean burn engine results in lower heat rate (energy input into the system), causing a loss in engine thermal efficiency.

Many 2SLB engines, such as naturally aspirated engines at the Blanco A, do not have identical air-to-fuel ratios in each cylinder, which can result in limited ability to vary the air-to-fuel ratio. To maintain acceptable engine performance at lean conditions, high-energy ignition systems (HEIS) have been developed that promote flame stability at very lean conditions.[6]

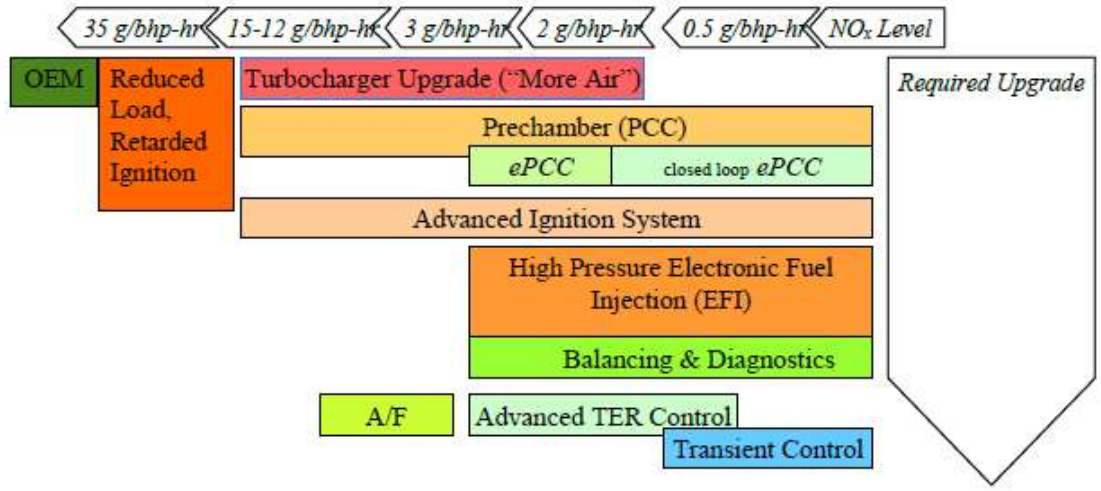
2SLB engines are mechanically capable of being retrofitted with more sensitive air-to-fuel ratio controllers and running on higher air-to-fuel ratio combustion to control NO_X emissions. Therefore, it has been determined that this method of NO_X control is feasible for the 2SLB engines at the Blanco A

[5] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
[6] Ibid

Compressor Station. Air-to-fuel ratio adjustment generally achieves a 5 to 30% reduction in NO_X emissions; however, this reduction is very specific to each engine and typical loading[7].

The 14 reciprocating engines at the Blanco A currently do not have controls installed and operate under the original manufacturer design. EPNG obtained an estimate from Hoerbiger Engineering Services (HES) for retrofitting the 14 reciprocating engines at the Blanco A with LEC technology. Hoerbiger utilizes a "Layered Approach Strategy" (Figure 1) to efficiently run the units while reducing NOx formation. The layered approach includes a turbocharger, advanced ignition system, Pre-Combustion Chambers (PCC) System, High Pressure Fuel Injection, and an Automatic Balancing Platform. Based on manufacturer guidance, the addition of these clean burn technologies allows the engines to range from 3 to 0.5 g/hp-hr in NO_X emissions. Further assessment of these control practices is discussed below.

Figure 1. Hoerbiger's Layered Approach Strategy for Clean Burn Technologies



3.2.2.1. LEC Option 1 (LEC 1) – Target NOx Emissions of 3 g/hp-hr

Based on the Hoerbiger Budgetary Estimate from September 2019, LEC 1 would include adding skid mounted VFD electric motor driven blower with Aftercooler, *HyperFuel*™ System, and Engine auxiliary cooling system. With the LEC 1 control option, the reciprocating engines at the Blanco A would achieve 3 g/hp-hr for NOx output. HES has indicated that it will be able to meet the NOx requirement and avoid a negative impact on CO emissions with LEC 1.

To maintain acceptable engine performance at lean conditions, a high energy ignition system is required for ignition of the air fuel charge in the LEC design that promotes flame stability at very lean conditions. The *HyperFuel Valve*™ System is an all-electronic high pressure fuel injection system that improves engine performance and emissions through enhanced mixing.

After-cooling is a technology to lower the intake charge air temperature thereby lowering peak cylinder temperatures and NOx formation. Cooler intake temperatures offer the potential for increased power output and improved fuel economy.

[7] Ibid

3.2.2.2. LEC Option 2 (LEC 2) – Target NOx Emissions of 1 g/hp-hr

LEC 2 would include adding Wet to Dry Manifold Conversion, Muffler with Oxidation Catalyst, and Cylinder Heads with PCC to the LEC 1 base option. With the LEC 2 control option, the reciprocating engines at the Blanco A would achieve 1 g/hp-hr for NOx output while maintaining CO emissions at the current permitted level.

LEC is combustion of a very fuel lean mixture. A fuel lean mixture acts as a heat sink, lowers cylinder temperatures and further reduces NOx formation. There is a tradeoff relationship between NOx and CO when air fuel ratio is adjusted. Lower NOx level will result in higher CO level. To address the concerns for elevated CO emissions in LEC, oxidation catalyst is added to prevent the CO emission from increasing beyond the currently permitted level when the NOx emission is reduced.

Pre-combustion chambers (PCC) have been utilized for improved mixing and enhanced ignition. The purpose of the PCC is to speed the combustion process, and to increase power output by increasing engine speed. The addition of a PCC increases heat loss to the cooling system and thereby lowers engine efficiency.

3.2.2.3. LEC Option 3 (LEC 3) – Target NOx Emissions of 0.5 g/hp-hr

LEC 3 would include uprating nine (9) engines at the Blanco A and retiring the remaining five (5) engines. In order to maintain the overall station horsepower (HP) level of 13,202, each of the 9 engines would be uprated to 1,463 HP. LEC 3 would include adding a *HyperFuel*™ System, Turbocharger, Compressor Cylinder Upgrade, and Power Cylinder Upgrade.

In the lean burn engines, increasing the air to fuel ratio decreases the NOx emissions. Extra air dilutes the combustion gases, thus lowering peak flame temperature and reducing thermal NOx formation. In order to avoid de-rating, combustion air to the engine must be increased at constant fuel flow, requiring a turbocharger. Turbocharger compresses more air flow into the engine's cylinder**.** When air is compressed the oxygen molecules are packed closer together. This increase in air means that more fuel can be added for the same size naturally aspirated engine. This then generates increased mechanical power and overall efficiency improvement of the combustion process. Turbochargers are added to provide the additional combustion air to achieve the ultra-low NOx emission level. The turbochargers proposed by HES are of high efficiency design which provides for the widest possible operating range. Intercoolers are installed to complement the turbocharging. This will keep the air manifold temperature at a fixed temperature at all operating and ambient conditions.

3.2.3. Good Combustion Practices and Fuel Selection

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review for the control of NO_X emissions from large natural gas-fired lean-burn stationary internal combustion engines; therefore, it has been determined that this method of NO_X control is feasible for the 2SLB engines at the Blanco A. EPNG

has an operation and maintenance program for the reciprocating engines, which is based on manufacturer recommendation, and EPNG has systems in place to ensure that the engines are operated in accordance with the program at the Blanco A. No further assessment of these control practices is included in this report.

3.2.4. Reducing Capacity

These engines, and in fact, the entire fleet of ENPG's engines and turbines, are part of interstate natural gas pipelines that are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the federal Natural Gas Act. See, e.g., 18 C.F.R.§284.7(a) (setting forth requirements for interstate natural gas firm transportation service). FERC approves or "certificates" the pipeline to deliver natural gas. EPNG's pipeline system, as certificated by FERC, so that EPNG can move gas 24 hours a day, 365 days a year at its designed capacity. Reducing capacity of one or more of EPNG's engines or turbines would require that EPNG seek and obtain approval from FERC. Abandonment proceedings can take up to 11-13 months.

Additionally, as noted in Section 3.2.6 below, replacement of units, and by extension retirement of existing units, is beyond the scope of the Regional Haze Rule. The Clean Air Act, 42 USC Section 7491(g)(2) and elsewhere uses the term "best available retrofit technology." The term "retrofit" denotes modifications to existing equipment and not replacement of equipment. EPA itself acknowledged this in Appendix Y to 40 CFR Part 51 entitled "Guidelines for BART Determinations under the Regional Haze Rule".

However, in evaluating its response to both the New Mexico Ozone Precursor Rule 20.2.50 NMAC and the Regional Haze Rule, EPNG notes that both rules potentially affect Blanco A. In brief, under the Alternative Compliance Plan (ACP) soon to be submitted to the State, EPNG is proposing to retire seven units at Blanco A as part of the overall emission reduction efforts even though the engines are not technically subject to the Ozone Precursor Rule if, an only if, the retirement is approved as a compliance strategy under both regulations and by FERC. Part of the retirement plan is the good will reduction in NOx emissions beyond what is required by the Ozone Precursor Rule. The retirement would also provide benefits under the Regional Haze Rule. While not economically feasible as defined by the Regional Haze Rule, this solution is lower cost than other more-costly or technically infeasible NOx-reduction options.

Accordingly, EPNG requests that NMED consider this environmentally advantageous solution under both rules even though it is not mandated by either rule.

3.2.5. Selective Non-Catalytic Reduction (SNCR)

SNCR is applicable to lean burn natural gas fired engines. SNCR involves injecting ammonia or urea into exhaust with temperatures greater than 1400-1500°F. The NOx in the exhaust are reduced to nitrogen and water vapor. The exhaust temperatures from these engines at the Blanco A are typically in the range of 450-600°F, thus, SNCR is not feasible to reduce NOx emissions in these engines.

3.2.6. Replacement with Electric Drive Motors

NMED's "Recommended Format for Four-Factor Analyses for Regional Haze Planning in New Mexico[9]" provides guidance on selection process for NOx emissions control options. Specifically, it requests affected source to "[D]escribe all of the existing and potential control options to be analyzed (e.g., combustion modifications, post-combustion NOx controls, or fuel substitution…". (Emphasis added.)

The use of "control" here contemplates that emissions sources will evaluate the cost-effectiveness of technically feasible controls on the existing emission sources to reduce emissions – not eliminate or replace those emissions sources altogether. NMED's evaluation of technical feasibility and cost-effective control measures have been limited to specific control technologies available for the existing units. This is an appropriate scope, and EPNG agrees that replacement of the compressor engines with electric drive motors would be beyond the scope of the requirement of the RHR and NMED's authority.

4.1. FACTOR 1: COST OF COMPLIANCE

Control costs include both the capital costs associated with the purchase and installation of retrofit and control systems, as well as the net annual costs (annual recurring costs) associated with system operation. The basic components of total capital costs are direct capital costs, which includes purchased equipment and installation costs, and indirect capital expenses.

Direct capital costs consist of such items as purchased equipment, instrumentation and process controls, ductwork and piping, electrical components, and structural and foundation costs. Labor costs associated with construction and installation are also included in this category.

Indirect capital expenses are comprised of engineering and design costs, contractor fees, supervisory expenses, and startup and performance testing. Contingency costs – which represent such costs as construction delays, increased labor and equipment costs, and design modifications – are an additional component of indirect capital expenses. Capital costs also include the cost of process modifications.

Annual costs include amortized costs of capital investment, as well as cost of operating labor, additional operation and maintenance cost associated with the controls, additional utility costs, and waste disposal.

Only control options deemed technically feasible to the engines at the Blanco A were analyzed. Detailed calculations for each option can be found in Appendix B.

4.1.1. Low Emission Combustion Option 1

The cost of compliance for LEC 1 was analyzed using vendor cost estimates along with the procedures found in the EPA Air Pollution Control Cost Manual (CCM) as applicable. The LEC 1 assumes a NOx emissions rate of 3 g/hp-hr after controls.

Overall, economic feasibility is evaluated on a dollar-per-ton (2019 $/ton)[8] basis using the annual operating cost ($/yr) divided by the annual emission reduction achieved by the control device (ton/yr). The initial total capital investment (TCI) was annualized over a 20-year period and added to the annual operating costs, and the interest rate reflects EPNG's actual cost of borrowing**.** This approach is consistent with EPA's Cost Control Manual (CCM) Section 1, Chapter 2, where EPA states that "…if firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates…" Therefore, in keeping with EPA's CCM, using firm-specific interest rate to develop the cost analysis is appropriate. For the cost analysis, EPNG reviewed the operating data and emission test data from 2015-2019; the highest actual test data and the highest annual operating hours were used to calculate the projected uncontrolled annual emissions (ton/yr). This approach of projecting uncontrolled annual emissions is more conservative than assigning a 5% increase to the average of 2016-2018 actual emissions. The findings of the cost effectiveness of LEC 1 is summarized in Table 3.

[8] NMED Recommended Format for Four-Factor Analysis for Regional Haze Planning in New Mexico

Table 3. Summary of Cost Effectiveness for LEC 1

Unit ID	Uncontrolled NOx Emissions (tpy)	Controlled NOx Emissions (tpy)	NOx Emissions Reduction (tpy)	Total Annualized Cost ($/yr)	Cost Effectiveness ($/ton reduced)
A-01	24.22	20.98	3.24	$435,943	$134,528
A-02	1.92	6.86	No Reduction*	$367,978	--
A-03	36.70	18.57	18.14	$424,314	$23,394
A-04	0.23	1.59	No Reduction*	$342,638	--
A-05	0.80	0.88	No Reduction*	$339,202	--
A-06	29.76	17.36	12.40	$418,519	$33,762
A-07	40.38	25.96	14.42	$459,914	$31,900
A-08	0.01	0.01	No Reduction*	$335,012	--
A-09	12.96	9.79	3.16	$382,112	$120,854
A-10	0.02	0.02	No Reduction*	$335,079	--
A-11	32.73	26.24	6.49	$461,228	$71,045
A-12	13.94	11.10	2.84	$388,407	$136,939
A-13	20.08	23.36	No Reduction*	$447,381	--
A-14	6.07	22.80	No Reduction*	$444,706	--

*The highest test results for units 2, 4, 5, 13, and 14 are less than the NOx target of 3 g/hp-hr; therefore LEC 1 would not achieve NOx emission reductions for these units. Units 8 and 10 have limited projected hours to show any NOx emission reductions.

Therefore the cost per ton of NOx reductions for LEC 1 is between $23,394 and $136,939 per engine. Based on a cost effectiveness threshold of $7,500/ton, LEC 1 is economically infeasible for all engines.

4.1.2. Low Emission Combustion Option 2

The cost of compliance for LEC 2 was analyzed using the same approach as that of LEC 1. LEC 2 assumes a NOx emissions rate of 1 g/hp-hr after controls. The findings of the cost effectiveness of LEC 2 is summarized in Table 4.

Table 4. Summary of Cost Effectiveness for LEC 2

Unit ID	Uncontrolled NOx Emissions (tpy)	Controlled NOx Emissions (tpy)	NOx Emissions Reduction (tpy)	Total Annualized Cost ($/yr)	Cost Effectiveness ($/ton reduced)
A-01	24.22	6.99	17.23	$713,721	$41,427
A-02	1.92	2.29	No Reduction*	$576,554	--
A-03	36.70	6.19	30.51	$690,252	$22,620
A-04	0.23	0.53	No Reduction*	$525,414	--
A-05	0.80	0.29	0.50	$518,479	$1,029,568
A-06	29.76	5.79	23.97	$676,261	$28,213
A-07	40.38	8.65	31.73	$762,098	$24,021
A-08	0.01	0.00	0.01	$510,022	$97,332,475
A-09	12.96	3.26	9.69	$605,081	$62,433
A-10	0.02	0.01	0.01	$510,156	$39,628,377
A-11	32.73	8.75	23.98	$764,751	$31,887
A-12	13.94	3.70	10.24	$617,784	$60,340
A-13	20.08	7.79	12.29	$736,804	$59,957
A-14	6.07	7.60	No Reduction*	$731,406	--

*The highest test results from units 2, 4, and 14 are less than the NOx target of 1 g/hp-hr; therefore LEC 2 would not achieve NOx emission reduction for these units.

Therefore the cost per ton of NOx reductions for LEC 2 is between $22,620 and $97,332,475 per engine. Based on a cost effectiveness threshold of $7,500/ton, LEC 2 is economically infeasible for all engines.

4.1.3. Low Emission Combustion Option 3

LEC 3 would include the retirement of five engines at the Blanco A while uprating the remaining nine engines in order to maintain the overall station HP level of 13,202. LEC 3 assumes a NOx emissions rate of 0.5 g/hp-hr. Note the 0.5 g/hp-hr NOx emission rate is difficult to sustain on a consistent basis due to

operational variations in natural gas compressor applications. The findings of the cost effectiveness of LEC 3 is summarized in Table 5.

Table 5. Summary of Cost Effectiveness for LEC 3

Unit ID	Uncontrolled NOx Emissions (tpy)	Controlled NOx Emissions (tpy)	NOx Emissions Reduction (tpy)	Total Annualized Cost ($/yr)	Cost Effectiveness ($/ton reduced)
A-01	24.22	3.50	20.73	$636,317	$30,702
A-02	1.92	1.14	0.78	$523,034	$669,495
A-03	36.70	3.09	33.61	$616,934	$18,356
A-04	0.23	0.27	No Reduction*	$480,798	--
A-05	0.80	0.15	0.65	$475,071	$731,144
A-06	29.76	2.89	26.86	$604,981	$22,521
A-07	40.38	4.33	36.05	$676,271	$18,757
A-08	0.01	0.00	0.01	$468,087	$75,013,871
A-09	12.96	1.63	11.32	$546,593	$48,268
A-10	0.02	0.00	0.02	$468,196	$28,808,988
A-11	32.73	4.37	28.36	$678,461	$23,927
A-12	13.94	1.85	12.09	$557,085	$46,083
A-13	20.08	3.89	16.18	$655,381	$40,501
A-14	6.07	3.80	2.27	$650,923	$286,897

*The highest emission test result for unit 4 is less than the NOx target of 0.5 g/hp-hr; therefore LEC 3 would not achieve NOx emission reduction for unit 4.

Therefore the cost per ton of NOx reductions for LEC 3 is between $18,356 and $75,013,871 per engine. Based on a cost effectiveness threshold of $7,500/ton, LEC 3 is economically infeasible for all engines.

4.1.4. Good Combustion Practices

Utilizing good combustion practices and fuel selection were identified as technical feasible for the control of NOx emissions. EPNG has developed Engine Inspection and Maintenance Schedules Best Practices procedures based on manufacturer recommendation, and EPNG has systems in place to ensure that its engines are operated in accordance with the schedules. These practices are currently in used at the Blanco A. By maintaining good combustion practices and using pipeline quality natural gas as fuel, the units will operate as intended with the lowest NO_X emissions possible. No further assessment of these control practices is included in this report.

4.2. FACTOR 2: TIME NECESSARY FOR COMPLIANCE

The time necessary for compliance is separate from the other three factors. The time necessary for compliance depends on reasonable installation times and compliance deadlines for selected control measures. Combustion modifications and post-combustion NOx controls may require significant time for engineering, construction, and facility preparedness. As an exact timeframe cannot be projected for the analyzed control options, an estimate was made for each option. Furthermore, not all engines would be able to be modified simultaneously as pressure must be maintained within the transmission pipeline at all times. Estimates were made between 1 and 3 years, after the issuance of the revised permit from NMED, depending on the control selected.

4.3. FACTOR 3: ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS

The proposed emission reduction strategies include high-pressure fuel injection systems, which take electricity to operate over and above the electricity usage of the facility in its current configuration. The proposed use of a catalyst in LEC 2 would generate waste and disposal issues when the catalyst is cleaned or replaced. The construction phase of the project would also generate solid and potentially hazardous waste for disposal, potentially create odor and noise pollution, and additional temporary combustion emissions from equipment. The LEC control technology may also decrease engine efficiency.

4.4. FACTOR 4: REMAINING USEFUL LIFE OF THE SOURCE

Slow speed engines such as the Cooper Bessemer GMV10-TF installed at Blanco A are very robust engines. The oldest engines in the Kinder Morgan fleet were designed and installed in the 1940s. When properly maintained, these engines will continue to operate for the foreseeable future with periodic routine maintenance. Cooper continues to make parts for replacement. Additionally, the EPA's Air Pollution Control Cost Manual suggests the remaining useful life should be based on the control method and not the emissions source itself. Therefore, it is assumed that the remaining useful life of any chosen control or modification is 20 years.

5. SUMMARY & CONCLUSIONS

NMED has indicated costs in excess of $7,500/ton of pollutant reduced are economically infeasible. This cost threshold is cited in the preamble to rulemaking for 20.2.50 NMAC and has been utilized by other States to define an acceptable level for determination of cost effectiveness for control technologies. As shown in this analysis, the economic feasibility values are above $7,500/ton of pollutant reduced for each of the technological feasible emission controls for the 14 engine units at the Blanco A. Based on a comprehensive review of the RBLC, available literature, and vendor input of available control technologies for the natural gas fired engines located at the Blanco A, EPNG has determined that good combustion practices and using pipeline quality natural gas as fuel are the only technically feasible control options for the 14 reciprocating engines.

However, EPNG recognizes that there is overlap between the New Mexico Ozone Precursor Rule and the Regional Haze Rule. Although not required under either rule, EPNG proposes that NMED allow EPNG to retire seven units at Blanco A if, an only if, the retirement is approved as a compliance strategy under both regulations and by FERC.

In summary, subject to FERC approval and if, and only if, NMED approves this compliance strategy under both the Ozone Precursor Rule and the Regional Haze Rule EPNG is proposing for compliance with the Regional Haze Rule:

- Retirement of seven of the 14 engines at Blanco A, and
- Continued implementation of GCP on the remaining seven engines.

6. SUPPORTING DOCUMENTATION

Appendix A – RBLC Table

Appendix B – Cost Analysis

APPENDIX A – RBLC TABLE

RBLC Analysis for Natural Gas-Fired Lean-Burn Stationary Internal Combustion Engines – NO_x

	Control Technology	Selective Catalytic Reduction (SCR) [a,b]	Non-Selective Catalytic Reduction (NSCR) [b]	Clean Burn Technology	Good Combustion Practices and Fuel Selection [c]
IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	A nitrogen-based reagent (e.g., ammonia, urea) is injected into the exhaust stream downstream of the combustion unit. The reagent reacts selectively with NO_x to produce molecular N_2 and water in a reactor vessel containing a metallic or ceramic catalyst.	This technique uses residual hydrocarbons and CO in rich-burn engine exhaust as a reducing agent for NO_x. In an NSCR, hydrocarbons and CO are oxidized by O_2 and NO_x. The excess hydrocarbons, CO, and NO_x pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H_2O and CO_2, while reducing NO_x to N_2. [b]	Natural gas fueled engines that operate with a fuel-lean air/fuel ratio are capable of low NO_x emissions.	NO_x emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following EPA's "Good Combustion Practices" guidance document, good combustion practices can be maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices the unit will operate as intended with the optimal NO_x emissions.
	Other Considerations	Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as "ammonia slip." Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.	N/A	N/A	N/A
ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Not included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Not included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.
	Feasibility Discussion	Technically infeasible. For engines which typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia to gain the reductions needed.	Technically infeasible. The NSCR technique is limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes 4-stroke rich-burn naturally aspirated engines and some 4-stroke rich-burn turbocharged engines. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures.	Technically feasible.	Technically feasible.
RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency			27% - 82%	Base Case

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
b. U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
c. EPA Guidance document "Good Combustion Practices" available at: http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf.

APPENDIX B – COST ANALYSIS

EPNG Blanco A Compressor Station Uncontrolled 2028 Emissions Projection

Unit No.	Operating Hours (hr/yr)					NOx EF (lb/hr) Based on the Highest Test Data (2015-2019)	Projected 2028 Hours Based on Highest (2015-2019) Hrs/yr	Projected 2028 NOx Emissions (tpy) based on Highest Test Data and Actual Hours from 2015-2019
	2015	2016	2017	2018	2019			
A-1	2655.4	6728.5	5123.0	579.0	3787.0	7.2	6728.5	24.22
A-2	1.8	2.3	14.8	4.3	2199.0	1.75	2199.0	1.92
A-3	5884.8	5012.8	5953.5	3182.0	5181.5	12.33	5953.5	36.70
A-4	1.5	99.8	2.5	2.0	510.3	0.9	510.3	0.23
A-5	1.8	281.3	5.0	9.5	2.5	5.66	281.3	0.80
A-6	195.1	56.0	5567.3	2155.3	1.5	10.69	5567.3	29.76
A-7	8326.0	5964.5	6666.3	1371.0	3690.8	9.7	8326.0	40.38
A-8	2.0	1.8	1.3	1.3	1.5	7.24	2.0	0.01
A-9	367.3	2499.5	183.5	866.5	3141.0	8.25	3141.0	12.96
A-10	1.3	1.8	1.8	6.5	1.3	6.04	6.5	0.02
A-11	8413.6	4404.7	3239.5	7450.8	6580.3	7.78	8413.6	32.73
A-12	2.5	1.5	2.3	3560.5	2.3	7.83	3560.5	13.94
A-13	899.0	7490.8	6827.8	6108.8	7129.8	5.36	7490.8	20.08
A-14	2.0	1.8	1.3	7312.5	3259.0	1.66	7312.5	6.07

Cost Analysis for Low Emission Controls for Engine A-1

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	6,729	6,729	6,729	Projection based on the highest actual of 2015-2019
EQUIPMENT COST (EC)					
Cost per engine		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Pulsation Bottles		$0	$0	$900,000	
Total Cost per engine (TC)		$1,884,728	$2,975,000.29	$2,804,837.56	
Contingency Cost per unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Cost		$26,386,196	$41,650,004	$25,243,538	
Total Capital Investment per Unit (TCI)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		972	972	972	15% of operator
Maintenance Labor & Material Cost [1, 3]		$95,915	$198,713	$163,234	
Testing		$10,000	$10,000	$10,000	Annual Reference Method Test
Added Electricity Cost	5 kW/hr	$5,046	$5,046	$5,046	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$118,414**	**$221,211**	**$185,733**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [2]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$435,943**	**$713,721**	**$636,317**	
Uncontrolled NOx Emissions Projection	tpy	24.22	24.22	24.22	Projection based on highest test data and highest actual hours from 2015-2019
Controlled NOx Emissions	tpy	20.98	6.99	3.50	
Controlled NOx Concentration	g/hp-hr	3.0	1.0	0.5	
NOx Emissions Removed	tpy	3.24	17.23	20.73	
Cost Effectiveness	$/ton	**$134,528**	**$41,427**	**$30,702**	

[1] Per EPA Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engine" EPA-453/R93-032, page 6-37, total maintenance (labor and materials) is calculated to be equal to 10% of the purchased equipment cost, prorated based on the operating hours, adjusted to 2019 dollars.

[2] Capital Recovery Factor :

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

[3] Chemical Engineering Plant Cost Index

Year	Index
1990	357.6
1995	381.1
2019	607.0

Cost Analysis for Low Emission Controls for Engine A-2

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	2,199	2,199	2,199	Projection based on the highest actual of 2015-2019
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Investment per Unit (TCI)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Maintenance Labor & Material Cost [1, 3]		$31,347	$64,943	$53,348	
Testing		$10,000	$10,000	$10,000	Annual Reference Method Test
Added Electricity Cost	5 kw/hr	$1,649	$1,649	$1,649	City of Farmington rate = $0.15/kWh
Total O&M Costs		**$50,448**	**$84,044**	**$72,449**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [2]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$367,978**	**$576,554**	**$523,034**	
Uncontrolled NOx Emissions Projection	tpy	1.92	1.92	1.92	Projection based on highest test data and highest actual hours from 2015-2019
Controlled NOx Emissions	tpy	6.86	2.29	1.14	
Controlled NOx Concentration	g/hp-hr	3.0	1.0	0.5	
NOx Emissions Removed	tpy	-4.93	-0.36	0.78	
Cost Effectiveness	$/ton	**Not effective**	**Not effective**	**$669,495**	

[1] Per EPA Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engine" EPA-453/R93-032, page 6-37, total maintenance (labor and materials) is calculated to be equal to 10% of the purchased equipment cost, prorated based on the operating hours, adjusted to 2019 dollars.

[2] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

[3] Chemical Engineering Plant Cost Index

Year	Index
1990	357.6
1995	381.1
2019	607.0

Cost Analysis for Low Emission Controls for Engine A-3

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	5,954	5,954	5,954	Projection based on the highest actual of 2015-2019
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Constrution, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Pulsation Bottles		$0	$0	$900,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Investment per Unit (TCI)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Maintenance Labor & Material Cost [1, 3]		$84,868	$175,825	$144,433	
Testing		$10,000	$10,000	$10,000	Annual Reference Method Test
Added Electricity Cost	5 kW/hr	$4,465	$4,465	$4,465	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$106,785**	**$197,742**	**$166,350**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [2]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$424,314**	**$690,252**	**$616,934**	
Uncontrolled NOx Emissions Projection	tpy	36.70	36.70	36.70	Projection based on highest test data and highest actual hours from 2015-2019
Controlled NOx Emissions	tpy	18.57	6.19	3.09	
Controlled NOx Concentration	g/hp-hr	3.0	1.0	0.5	
NOx Emissions Removed	tpy	18.14	30.51	33.61	
Cost Effectiveness	$/ton	**$23,394**	**$22,620**	**$18,356**	

[1] Per EPA Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engine" EPA-453/R93-032, page 6-37, total maintenance (labor and materials) is calculated to be equal to 10% of the purchased equipment cost, prorated based on the operating hours, adjusted to 2019 dollars.

[2] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

[3] Chemical Engineering Plant Cost Index

Year	Index
1990	357.6
1995	381.1
2019	607.0

Cost Analysis for Low Emission Controls for Engine A-4

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	510	510	510	Projection based on the highest actual of 2015-2019
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Investment per Unit (TCI)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required	hrs/day	$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Maintenance Labor & Material Cost [1, 3]		$7,274	$15,069	$12,379	
Testing		$10,000	$10,000	$10,000	Annual Reference Method Test
Added Electricity Cost	5 kW/hr	$383	$383	$383	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$25,108**	**$32,904**	**$30,213**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [2]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$342,638**	**$525,414**	**$480,798**	
Uncontrolled NOx Emissions Projection	tpy	0.23	0.23	0.23	Projection based on highest test data and highest actual hours from 2015-2019
Controlled NOx Emissions	tpy	1.59	0.53	0.27	
Controlled NOx Concentration	g/hp-hr	3.0	1.0	0.5	
NOx Emissions Removed	tpy	-1.36	-0.30	-0.04	
Cost Effectiveness	$/ton	**Not effective**	**Not effective**	**Not effective**	

[1] Per EPA Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engine" EPA-453/R93-032, page 6-37, total maintenance (labor and materials) is calculated to be equal to 10% of the purchased equipment cost, prorated based on the operating hours, adjusted to 2019 dollars.

[2] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

[3] Chemical Engineering Plant Cost Index

Year	Index
1990	357.6
1995	381.1
2019	607.0

Cost Analysis for Low Emission Controls for Engine A-5

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	281	281	281	Projection based on the highest actual of 2015-2019
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Pulsation Bottles		$0	$0	$900,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	from Good Neighbor cost estimate of similar unit
Total Capital Cost per Unit (TCC)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Maintenance Labor & Material Cost [1, 3]		$4,009	$8,306	$6,823	
Testing		$10,000	$10,000	$10,000	Annual Reference Method Test
Added Electricity Cost	5 kW/hr	$211	$211	$211	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$21,672**	**$25,969**	**$24,486**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [2]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$339,202**	**$518,479**	**$475,071**	
Uncontrolled NOx Emissions Projection	tpy	0.80	0.80	0.80	Projection based on highest test data and highest actual hours from 2015-2019
Controlled NOx Emissions	tpy	0.88	0.29	0.15	
Controlled NOx Concentration	g/hp-hr	3.0	1.0	0.5	
NOx Emissions Removed	tpy	-0.08	0.50	0.65	
Cost Effectiveness	$/ton	**Not effective**	**$1,029,568**	**$731,144**	

[1] Per EPA Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engine" EPA-453/R93-032, page 6-37, total maintenance (labor and materials) is calculated to be equal to 10% of the purchased equipment cost, prorated based on the operating hours, adjusted to 2019 dollars.

[2] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

[3] Chemical Engineering Plant Cost Index

Year	Index
1990	357.6
1995	381.1
2019	607.0

Cost Analysis for Low Emission Controls for Engine A-6

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	5,567	5,567	5,567	Projection based on the highest actual of 2015-2019
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles (14 units)		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Investment per Unit (TCI)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Maintenance Labor & Material Cost [1, 3]		$79,362	$164,418	$135,062	
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost	5 kW/hr	$4,175	$1,882	$1,882	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$100,989**	**$183,752**	**$154,396**	
Admin, insurance, taxes	4% of TCI	$87,053	$135,025	$123,531	
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [2]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$418,519**	**$676,261**	**$604,981**	
Uncontrolled NOx Emissions Projection	tpy	29.76	29.76	29.76	Projection based on highest test data and highest actual hours from 2015-2019
Controlled NOx Emissions	tpy	17.36	5.79	2.89	
Controlled NOx Concentration	g/hp-hr	3.0	1.0	0.5	
NOx Emissions Removed	tpy	12.40	23.97	26.86	
Cost Effectiveness	$/ton	**$33,762**	**$28,213**	**$22,521**	

[1] Per EPA Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engine" EPA-453/R93-032, page 6-37, total maintenance (labor and materials) is calculated to be equal to 10% of the purchased equipment cost, prorated based on the operating hours, adjusted to 2019 dollars.

[2] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

[3] Chemical Engineering Plant Cost Index

Year	Index
1990	357.6
1995	381.1
2019	607.0

Cost Analysis for Low Emission Controls for Engine A-7

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	8,326	8,326	8,326	Projection based on the highest actual of 2015-2019
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles (14 units)		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit	10% of TC	$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Cost per Unit (TCC)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required (.5 hr/shift, similar to EPA example)		$6,480	$6,480	$6,480	
Supervisor labor		$972	$972	$972	15% of operator
Maintenance Labor & Material Cost [1, 3]		$118,688	$245,892	$201,990	
Testing		$10,000	$10,000	$10,000	Annual Reference Method Test
Added Electricity Cost	5 kW/hr	$6,245	$6,245	$6,245	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$142,384**	**$269,589**	**$225,686**	
Admin, insurance, taxes	4% of TCI	$87,053	$135,025	$123,531	
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [2]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$459,914**	**$762,098**	**$676,271**	
Uncontrolled NOx Emissions Projection	tpy	40.38	40.38	40.38	Projection based on highest test data and highest actual hours from 2015-2019
Controlled NOx Emissions	tpy	25.96	8.65	4.33	
Controlled NOx Concentration	g/hp-hr	3.0	1.0	0.5	
NOx Emissions Removed	tpy	14.42	31.73	36.05	
Cost Effectiveness	$/ton	**$31,900**	**$24,021**	**$18,757**	

[1] Per EPA Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engine" EPA-453/R93-032, page 6-37, total maintenance (labor and materials) is calculated to be equal to 10% of the purchased equipment cost, prorated based on the operating hours, adjusted to 2019 dollars.

[2] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

[3] Chemical Engineering Plant Cost Index

Year	Index
1990	357.6
1995	381.1
2019	607.0

Cost Analysis for Low Emission Controls for Engine A-8

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	2	2	2	Projection based on the highest actual of 2015-2019
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$910,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Pulsation Bottles		$0	$0	$900,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit	10% of TC	$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Investment per Unit (TCI)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Maintenance Labor & Material Cost [1, 3]		$29	$59	$49	
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost	5 kW/hr	$2	$2	$2	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$17,482**	**$17,513**	**$17,502**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life		20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [2]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$335,012**	**$510,022**	**$468,087**	
Uncontrolled NOx Emissions Projection	tpy	0.01	0.01	0.01	Projection based on highest test data and highest actual hours from 2015-2019
Controlled NOx Emissions	tpy	0.01	0.00	0.00	
Controlled NOx Concentration	g/hp-hr	3.0	1.0	0.5	
NOx Emissions Removed	tpy	0.00	0.01	0.01	
Cost Effectiveness	$/ton	**$333,933,778**	**$97,332,475**	**$75,013,871**	

[1] Per EPA Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engine" EPA-453/R93-032, page 6-37, total maintenance (labor and materials) is calculated to be equal to 10% of the purchased equipment cost, prorated based on the operating hours, adjusted to 2019 dollars.

[2] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

[3] Chemical Engineering Plant Cost Index

Year	Index
1990	357.6
1995	381.1
2019	607.0

Cost Analysis for Low Emission Controls for Engine A-9

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	3,141	3,141	3,141	Projection based on the highest actual of 2015-2019
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Investment per Unit (TCI)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Maintenance Labor & Material Cost [1, 3]		$44,775	$92,763	$76,201	
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost	5 kW/hr	$2,356	$2,356	$2,356	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$64,583**	**$112,571**	**$96,009**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [2]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$382,112**	**$605,081**	**$546,593**	
Uncontrolled NOx Emissions Projection	tpy	12.96	12.96	12.96	Projection based on highest test data and highest actual hours from 2015-2019
Controlled NOx Emissions	tpy	9.79	3.26	1.63	
Controlled NOx Concentration	g/hp-hr	3.0	1.0	0.5	
NOx Emissions Removed	tpy	3.16	9.69	11.32	
Cost Effectiveness	$/ton	**$120,854**	**$62,433**	**$48,268**	

[1] Per EPA Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engine" EPA-453/R93-032, page 6-37, total maintenance (labor and materials) is calculated to be equal to 10% of the purchased equipment cost, prorated based on the operating hours, adjusted to 2018 dollars.

[2] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

[3] Chemical Engineering Plant Cost Index

Year	Index
1990	357.6
1995	381.1
2019	607.0

Cost Analysis for Low Emission Controls for Engine A-10

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	7	7	7	Projection based on the highest actual of 2015-2019
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	from Good Neighbor cost estimate of similar unit
Total Capital Cost per Unit (TCC)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Maintenance Labor & Material Cost [1, 3]		$93	$192	$158	
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost	5 kW/hr	$5	$2	$2	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$17,550**	**$17,646**	**$17,612**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [2]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$335,079**	**$510,156**	**$468,196**	
Uncontrolled NOx Emissions Projection	tpy	0.02	0.02	0.02	Projection based on highest test data and highest actual hours from 2015-2019
Controlled NOx Emissions	tpy	0.02	0.01	0.00	
Controlled NOx Concentration	g/hp-hr	3.0	1.0	0.5	
NOx Emissions Removed	tpy	0.00	0.01	0.02	
Cost Effectiveness	$/ton	**($523,961,738)**	**$39,628,377**	**28,808,988**	

[1] Per EPA Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engine" EPA-453/R93-032, page 6-37, total maintenance (labor and materials) is calculated to be equal to 10% of the purchased equipment cost, prorated based on the operating hours, adjusted to 2018 dollars.

[2] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

[3] Chemical Engineering Plant Cost Index

Year	Index
1990	357.6
1995	381.1
2019	607.0

Cost Analysis for Low Emission Controls for Engine A-11

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	8,414	8,414	8,414	Projection based on the highest actual of 2015-2019
EQUIPMENT COST (EC)					
Cost per engine		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Cost per Unit (TCC)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Maintenance Labor & Material Cost [1, 3]		$119,936	$248,479	$204,115	
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost	5 kW/hr	$6,310	$6,310	$6,310	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$143,698**	**$272,241**	**$227,877**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [2]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$461,228**	**$764,751**	**$678,461**	
Uncontrolled NOx Emissions Projection	tpy	32.73	32.73	32.73	Projection based on highest test data and highest actual hours from 2015-2019
Controlled NOx Emissions	tpy	26.24	8.75	4.37	
Controlled NOx Concentration	g/hp-hr	3.0	1.0	0.5	
NOx Emissions Removed	tpy	6.49	23.98	28.36	
Cost Effectiveness	$/ton	**$71,045**	**$31,887**	**$23,927**	

[1] Per EPA Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engine" EPA-453/R93-032, page 6-37, total maintenance (labor and materials) is calculated to be equal to 10% of the purchased equipment cost, prorated based on the operating hours, adjusted to 2018 dollars.

[2] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

[3] Chemical Engineering Plant Cost Index

Year	Index
1990	357.6
1995	381.1
2019	607.0

Cost Analysis for Low Emission Controls for Engine A-12

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure fuel injection & turbocharger & compressor cylinder and power cylinder upgrade + engine uprate of 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	3,561	3,561	3,561	Projection based on the highest actual of 2015-2019
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Cost per Unit (TCC)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Maintenance Labor & Material Cost [1, 3]		$50,755	$105,152	$86,378	
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost	5 kW/hr	$2,670	$2,670	$2,670	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$70,878**	**$125,275**	**$106,501**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [2]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$388,407**	**$617,784**	**$557,085**	
Uncontrolled NOx Emissions Projection	tpy	13.94	13.94	13.94	Projection based on highest test data and highest actual hours from 2015-2019
Controlled NOx Emissions	tpy	11.10	3.70	1.85	
Controlled NOx Concentration	g/hp-hr	3.0	1.0	0.5	
NOx Emissions Removed	tpy	2.84	10.24	12.09	
Cost Effectiveness	$/ton	**$136,939**	**$60,340**	**$46,083**	

[1] Per EPA Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engine" EPA-453/R93-032, page 6-37, total maintenance (labor and materials) is calculated to be equal to 10% of the purchased equipment cost, prorated based on the operating hours, adjusted to 2019 dollars.

[2] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

[3] Chemical Engineering Plant Cost Index

Year	Index
1990	357.6
1995	381.1
2019	607.0

Cost Analysis for Low Emission Controls for Engine A-13

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	7,491	7,491	7,491	Projection based on the highest actual of 2015-2019
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissionsing, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Cost pe Unit (TCC)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Maintenance Labor & Material Cost [1, 3]		$106,781	$221,225	$181,727	
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost		$5,618	$5,618	$5,618	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$129,851**	**$244,295**	**$204,797**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [2]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$447,381**	**$736,804**	**$655,381**	
Uncontrolled NOx Emissions Projection	tpy	20.08	20.08	20.08	Projection based on highest test data and highest actual hours from 2015-2019
Controlled NOx Emissions	tpy	23.36	7.79	3.89	
Controlled NOx Concentration	g/hp-hr	3.0	1.0	0.5	
NOx Emissions Removed	tpy	-3.28	12.29	16.18	
Cost Effectiveness	$/ton	**Not effective**	**$59,957**	**$40,501**	

[1] Per EPA Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engine" EPA-453/R93-032, page 6-37, total maintenance (labor and materials) is calculated to be equal to 10% of the purchased equipment cost, prorated based on the operating hours, adjusted to 2019 dollars.

[2] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

[3] Chemical Engineering Plant Cost Index

Year	Index
1990	357.6
1995	381.1
2019	607.0

Cost Analysis for Low Emission Controls for Engine A-14

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	7,313	7,313	7,313	Projection based on the highest actual of 2015-2019
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	from Good Neighbor cost estimate of similar unit
Total Capital Cost per Unit (TCC)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		972	972	972	15% of operator
Maintenance Labor & Material Cost [1, 3]		$104,240	$215,960	$177,402	
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost	5 kW/hr	$5,484	$5,484	$5,484	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$127,177**	**$238,897**	**$200,339**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [2]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$444,706**	**$731,406**	**$650,923**	
Uncontrolled NOx Emissions Projection	tpy	6.07	6.07	6.07	Projection based on highest test data and highest actual hours from 2015-2019
Controlled NOx Emissions	tpy	22.80	7.60	3.80	
Controlled NOx Concentration	g/hp-hr	3.0	1.0	0.5	
NOx Emissions Removed	tpy	-16.73	-1.53	2.27	
Cost Effectiveness	$/ton	**Not effective**	**Not effective**	**$286,897**	

[1] Per EPA Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engine" EPA-453/R93-032, page 6-37, total maintenance (labor and materials) is calculated to be equal to 10% of the purchased equipment cost, prorated based on the operating hours, adjusted to 2019 dollars.

[2] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

[3] Chemical Engineering Plant Cost Index

Year	Index
1990	357.6
1995	381.1
2019	607.0

NMED Final Cost Evaluation
El Paso Natural Gas Company - Pecos River Compressor Station

Facility Information

EPNG - Pecos River CS	**Facility**
Three 1950s vintage NG CT, 7,150 hp	**Units**
A-01, A-02, A-03	**Unit IDs**
SCR	**Evaluated Pollution Control**
80%	**SCR Control efficiency**

Supporting Information

2024	**Calendar year associated with cost estimates**
7150	**Maximum Power Output (hp/unit)**
60.7	**MMBtu HHV (heat input)**

Economic Evaluation

Cost Component		A-01	A-02	A-03	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	Included in TCC
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	Included in TCC
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	Included in TCC
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	Included in TCC
Total Capital Costs - Direct ($)	TCC	$ 3,352,801	$ 3,352,801	$ 3,352,801	EPA SCR Tool (2024$)	
Additional Capital ($)	AC	$ 3,275,000	$ 3,275,000	$ 3,275,000	EPNG initial FFA submittal	Turbine housing reconfiguration (2019$ adjusted to 2024$ using CEPCI)
Total Capital Investment ($)	TCI	$ 6,627,801	$ 6,627,801	$ 6,627,801	-	TCC + AC
Interest Rate (%)	R	8.53%	8.53%	8.53%	EPNG 2/23/2020 CFO letter and 10/9/2020 email	
Useful Life (yr)	Y	20	20	20	EPNG initial FFA submittal and 5/26/2023 email	
Capital Recovery Factor	CRF	0.1059	0.1059	0.1059	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 701,897	$ 701,897	$ 701,897	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 47,399	$ 64,571	$ 61,062	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 2,829	$ 2,829	$ 2,829	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 752,125	$ 769,297	$ 765,788	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	80%	80%	80%	EPA SCR Tool	Consistent with EPA and industry documentation
Baseline Actual NOx Emissions (ton/yr)	BAE	70.1	116.0	112.2	CY 2022/2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by EPNG
Projected Actual Emissions (ton/yr)	PAE	70.1	116.0	112.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	56.1	92.8	89.8	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 13,409**	**$ 8,290**	**$ 8,531**	-	TAC/ER

NMED Final Cost Evaluation
El Paso Natural Gas Company - Pecos River Compressor Station

Facility Information

EPNG - Pecos River CS	**Facility**
Three 1950s vintage NG CT, 7,150 hp	**Units**
A-01, A-02, A-03	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
15.0	**Target Emissions Rate (ppmvd @ 15% O2)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired CT >=4,100 hp and <15,900 hp.

Supporting Information

2023	**Calendar year associated with cost estimates**
7150	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		A-01	A-02	A-03	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 23,166,858	$ 23,166,858	$ 23,166,858	9/8/20 info from EPNG (2020$ converted to 2023$ with CEPCI)	All-in estimate ($/HP) x Maximum Capacity (HP)
Interest Rate (%)	R	8.53%	8.53%	8.53%	EPNG 2/23/2020 CFO letter and 10/9/2020 email	
Useful Life (yr)	Y	30	30	30	ERG experience based on discussions with CT manufacturers	
Capital Recovery Factor	CRF	0.0933	0.0933	0.0933	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 2,161,607	$ 2,161,607	$ 2,161,607	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 89,127	$ 89,127	$ 89,127	Other FFA submittals	Average difference in retrofit and conventional O&M costs provided by other companies
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 2,250,734	$ 2,250,734	$ 2,250,734	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	84%	86%	84%	-	(Current actual emissions rate - Target emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	70.1	116.0	112.2	CY 2022/2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by EPNG
Projected Actual Emissions (ton/yr)	PAE	70.1	116.0	112.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	58.9	100.0	94.2	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 38,185**	**$ 22,512**	**$ 23,884**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January - September data
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 38,185**	**$ 22,512**	**$ 23,884**	-	CE1 x PI

NMED Final Cost Evaluation
El Paso Natural Gas Company - Pecos River Compressor Station

Facility Information

EPNG - Pecos River CS	**Facility**
Three 1950s vintage NG CT, 7,150 hp	**Units**
A-01, A-02, A-03	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Target Emissions Rate (lb/hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
7150	**Rated Power Capacity (hp/unit)**
5156	**Operating Schedule (hr/yr, average)**

Economic Evaluation

Cost Component		All Units (Combined)	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	On 2/14/20, EPNG provided a $1469/hp all-in Total Capital Cost (TCC) metric for EMD. On 9/9/20, EPNG provided an alternate cost estimate developed using "the KM-Cost Estimating Group's Developmental Cost Estimating Tool". The alternate estimate applied an unusual and insufficiently documented methodology that involved a base cost estimate for replacement turbines that was adjusted using EMD-specific costs and turbine-specific costs. Using detailed cost information provided by other facilities, NMED developed a TCC metric of $2,084/hp (2023$) for the installation of EMD. Costs associated with requisite substation and utility line upgrades were estimated separately and added to TCC to estimate Total Capital Investment (TCI).
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ 44,701,800	See Note	
Additional Capital ($)	AC	$ 15,270,000	EPNG estimate dated 9/9/20 and ERG experience	15 miles of medium voltage line @ $750k/mile; substation upgrade ($3M in 2020$ converted to 2023$ using CEPCI)
Total Capital Investment ($)	TCI	$ 59,971,800	-	TCC + AC
Interest Rate (%)	R	8.53%	EPNG 2/23/2020 CFO letter and 10/9/2020 email	
Useful Life (yr)	Y	25	EPNG estimate dated 9/9/20	Consistent with other FFAs
Capital Recovery Factor	CRF	0.098	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 5,874,577	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 2,488,648	-	AED + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 5,208,648	ERG calculation	Assumes units at 60% load, 95% efficiency and a $0.10/kWh price
Associated non-electricity O&M ($/yr)	AOM	$ -	Engineering judgment	Assumed to be negligible
Annual Fuel Credit ($/yr)	AFC	$ (2,720,000)	EPNG 2/23/21 email	Cost of fuel based on calendar year 2016 operation
Other Indirect Annual Costs ($/yr)	OAC	$ -		4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 8,363,225	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	298.3	CY 2022/2023 emissions testing and average operating hours (2016-2021)	Sum of BAE of all units
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by EPNG
Projected Actual Emissions (ton/yr)	PAE	298.3	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	298.3	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 28,034**	-	TAC/ER
Price Index	PI	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January - September data
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 28,034**	-	CE1 x PI

NMED Final Cost Evaluation
El Paso Natural Gas Company - Pecos River Compressor Station

Unit A-01: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	61.8	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	212,973,230	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 2900 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.6392	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1278	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft³/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft³
29.4% aqueous NH_3	56 lbs/ft³

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	8.53	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit A-01: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	62	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	525,090,204	scf/Year	
Actual Annual fuel consumption (Mactual) =		212,973,230	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.406	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3553	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	31.60	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	56.14	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.11		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3064	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	268.91	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	12	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	42	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	6	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,000	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.1059

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	36.59	kW

Unit A-01: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$3,352,801	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$47,399 in 2024 dollars
Indirect Annual Costs (IDAC) =	$357,891 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$405,290 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$16,764 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$10,632 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$12,999 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$7,003 in 2024 dollars
Direct Annual Cost =		$47,399 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,829 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$355,062 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$357,891 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$405,290 per year in 2024 dollars
NOx Removed =	56 tons/year
Cost Effectiveness =	$7,220 per ton of NOx removed in 2024 dollars

Unit A-02: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	61.8	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	382,308,826	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	2900	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.5886	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1177	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft³/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft³
29.4% aqueous NH_3	56 lbs/ft³

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	8.53	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit A-02: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	62	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	525,090,204	scf/Year	
Actual Annual fuel consumption (Mactual) =		382,308,826	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.728	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6378	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	29.10	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	92.80	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.11		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3064	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	264.78	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	11	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	39	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,800	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.1059

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	36.59	kW

NMED Final Cost Evaluation
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Unit A-02: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$3,352,801	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$64,571 in 2024 dollars
Indirect Annual Costs (IDAC) =	$357,891 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$422,461 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$16,764 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$17,576 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$23,335 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$6,896 in 2024 dollars
Direct Annual Cost =		$64,571 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,829 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$355,062 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$357,891 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$422,461 per year in 2024 dollars
NOx Removed =	93 tons/year
Cost Effectiveness =	$4,553 per ton of NOx removed in 2024 dollars

Unit A-03: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	61.8	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	331,897,769	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	2900	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365	days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.6558	lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1312	lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050		Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
			Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	20	Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK ft^3/min-MMBtu/hour

* For industrial boilers, the typical equipment life is between 20 and 25 years.

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	8.53	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit A-03: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	62	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	525,090,204	scf/Year	
Actual Annual fuel consumption (Mactual) =		331,897,769	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.632	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5537	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	32.42	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	89.77	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.11		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3064	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	270.27	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	13	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	43	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	6	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,000	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.1059

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	36.59	kW

Unit A-03: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$3,352,801	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$61,062 in 2024 dollars
Indirect Annual Costs (IDAC) =	$357,891 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$418,953 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$16,764 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$17,002 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$20,258 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$7,039 in 2024 dollars
Direct Annual Cost =		$61,062 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,829 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$355,062 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$357,891 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$418,953 per year in 2024 dollars
NOx Removed =	90 tons/year
Cost Effectiveness =	$4,667 per ton of NOx removed in 2024 dollars

REGIONAL HAZE FOUR-FACTOR ANALYSIS

El Paso Natural Gas Company LLC
Pecos River Compressor Station

Prepared By:

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1. INTRODUCTION

In the 1977 amendments to the Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across the United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

> *(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A).*
>
> This is known as a four-factor analysis.
>
> *(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B).*
>
> The uniform rate of progress or improvement is sometimes referred to as the glidepath and is part of the state's Long-Term Strategy (LTS).

The second implementation planning period (2018-2028) for national regional haze efforts is currently underway. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural or biogenic and manmade or anthropogenic sources of emissions. Using a Photochemical Grid Model (PGM), the Western Region Air Partnership (WRAP), in coordination with the EPA, is tasked with comparing anthropogenic source contributions against natural background concentrations.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for major sources and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I area. From this analysis, 24 facilities were identified by the NMED. On July 18, 2019 the NMED informed El Paso Natural Gas Company LLC (EPNG) that its Pecos River Compressor Station (Pecos River) facility was identified as one of the sources potentially contributing to regional haze at the Carlsbad National Park Class I area.

In coordination with WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. In the NMED's July 18, 2019 notification letter to EPNG, it specifies that any equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The equipment at Pecos River, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant are reported in Table 1.

Table 1. Summary of Equipment and Applicability to a Four-Factor Analysis

Equipment	NO_X Hourly PTE (lb/hr)	NO_X Annual PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
Natural Gas-Fired Regenerative Cycle Turbine (Unit A-01)	53.10	232.58	Yes	0.43	1.87	No
Natural Gas-Fired Regenerative Cycle Turbine (Unit A-02)	53.10	232.58	Yes	0.43	1.87	No
Natural Gas-Fired Regenerative Cycle Turbine (Unit A-03)	53.10	232.58	Yes	0.43	1.87	No

NO_X is the only pollutant subject to evaluation in this four-factor analysis for the three turbines located at Pecos River: Units A-01, A-02 and A-03. These units are General Electric (GE) model M3712R (also known as Model A turbines) natural gas-fired, regenerative cycle turbines. They are rated at 7,150 horsepower each and were manufactured in 1953.

Once the applicability of equipment and pollutants has been determined, potential retrofit control technologies must be identified. In accordance with 40 CFR 51 Appendix Y and at the recommendation of the NMED[1], this is primarily achieved by utilizing the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) data. In order to determine the most relevant and current retrofit controls available, the RBLC is queried for the previous ten years. A summary of identified available retrofit controls along with a technical feasibility assessment for each control is provided in Section 2. The four-factor analysis is then conducted for those controls that are technically feasible.

[1] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

2.1. COMBUSTION TURBINE BACKGROUND

A gas turbine is an internal combustion engine that operates with a rotary, rather than reciprocating, motion and is composed of three primary components: a compressor, a combustor, and a power turbine. The compressor draws in ambient air and compresses it up to 30 times the ambient pressure, then directs it into the combustor where fuel is introduced, ignited, and burned. Exhaust gas from the combustor is then diluted with additional air and sent to the power turbine at temperatures up to 2600 °F. The hot exhaust gas expands in the power turbine section, generating energy in the form of shaft horsepower.[2]

The treatment of the exhaust gases exiting the turbine dictate the cycle designation of these units. The heat content can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).[3] The units at Pecos River are regenerative cycle turbines, which are essentially simple cycle gas turbines with an added heat exchanger.

NO_X is formed in turbines via three mechanisms:

(1) Thermal NO_X - the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion,
(2) Fuel NO_X - the evolution and reaction of fuel-bound nitrogen compounds with oxygen, and
(3) Prompt NO_X - the early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The Pecos River turbines use natural gas fuel, which contains a negligible amount of nitrogen compounds. Therefore, the formation of prompt and fuel NO_X will be insignificant. This analysis will focus on thermal NO_X. The rate of NO_X formation through the thermal NO_X mechanism is highly dependent upon the air-to-fuel ratio, combustion temperature, and residence time in the combustion chamber. Maximum thermal NO_X formation occurs near the stoichiometric air-to-fuel mixture ratio because combustion temperatures are greatest at this ratio.[4]

The PTE from each turbine is reported in the facility's New Source Review (3260M1) and Title V (P129R3M1) permits, as well as summarized in Table 1 of this report.

2.2. POTENTIAL NO_X CONTROLS FOR COMBUSTION TURBINES

There are three general methods of controlling NO_X emission from gas turbines; (1) dry controls, which use advanced combustor design to suppress NO_X formation, (2) wet controls that use steam or water injection to reduce combustion temperatures and NO_X formation, and (3) post-combustion, catalytic controls to selectively reduce NO_X.[5]

[2] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"
[3] Ibid.
[4] Ibid.
[5] Ibid.

The retrofit control equipment that was identified for combustion turbines during a comprehensive review of the RBLC, available literature, and manufacturer's input is reported in Table 2. A more detailed table summarizing the RBLC review is provided in Appendix A. A detailed discussion, including a description, the technical feasibility, and the anticipated performance of each control is provided below.

Table 2. Potential Control Options for Combustion Turbines

Control Equipment	Technically Feasible?	NO_X Control Efficiency
Good Combustion Practices	Yes	Base Case
Lean Head End Liner	No	N/A
Improved Combustion Technology	No	N/A
Water/Steam Injection	No	N/A
Selective Catalytic Reduction	Yes	65% - 90%

2.2.1. Good Combustion Practices

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from combustion turbines; therefore, it has been determined that this method of NO_X control is feasible for the units at Pecos River. EPNG has developed Turbine Inspection/Maintenance Schedules Best Practices procedures, included in Appendix B of this report, which are based on manufacturer recommendation, and EPNG has systems in place to ensure that its engines are operated in accordance with this. These practices are currently in use at Pecos River as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices is included in this report.

2.2.2. Lean Head End Combustion Liner

The key factors affecting thermal NO_X formation are the combustion temperature and residence time of fuel in the combustor. Maximum thermal NO_X formation occurs near the stoichiometric air-to-fuel mixture ratio because combustion temperatures are greatest at this ratio. "Lean" combustion refers to combustion occurring at a high air-to-fuel ratio, which reduces the firing temperature.

A Lean Head End (LHE) Combustion Liner is an enhanced liner for the combustion chamber that increases the air-to-fuel ratio by adjusting the number, diameter, and location of the mixing and dilution holes in the chamber.

This diverts excess air toward the flame end, thereby reducing the flame temperature and NO_X formation. GE estimates that NO_X reduction from this control method varies from 15% to 40%, depending upon the design.[6]

Based on communications with GE, there are currently no LHE liner control options for the GE Model A turbines. The earliest model on which the LHE liner can be installed is the Model J generation, which was produced starting in 1969 and has significant design differences to the Model A fleet. The LHE liner control technology has never been installed on units older than the Model J, and there is no way to determine what, if any, emissions reduction could be achieved through a retrofit.

Per 40 CFR Part 51, Appendix Y, "a technology is considered 'available' if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term."[7] Further, source owners are not expected to "construct a process or control device that has not already been demonstrated in practice."[8] Because LHE liners are not currently available for and have never been installed on the Model A fleet of turbines, there is no historical data to support that installation of these controls would result in significant reductions of NO_X emissions. For this reason, it has been determined that this control technology is infeasible for the turbines located at Pecos River.

2.2.3. Improved Combustion Technology

The improved combustion technology control option, commonly referred to as Dry Low NO_X (DLN) control, also seeks to reduce the combustion temperature and residence time of fuel in the combustor (thereby decreasing NO_X formation) by increasing the air-to-fuel ratio in the combustion chamber. There are several levels of improvements that can be made to the combustion chamber, which achieve this NO_X control at varying efficiencies.

Based on communications with GE, the DLN control option involves a thorough overhaul of the combustion section of the turbine, including replacement of the air and fuel injection nozzles, modifications to, or complete replacement, of the combustion chamber, and replacement of the electrical control system for the unit.

As with the LHE liners, there are currently no developed improved combustion controls available for the Model A fleet of GE turbines. The earliest model on which the DLN technology can be installed is the Model J turbines, and the technology has never been retrofitted for units older than the Model J. There is no way to determine what, if any, emissions reduction could be achieved through a retrofit. As there is no historical data to support that significant reductions of NO_X emissions would result from installation of this control, it has been determined that this control technology is infeasible for the turbines located at Pecos River.

2.2.4. Water/Steam Injection

Water or steam injection is a control technology for gas turbines that has been demonstrated to effectively suppress NO_X emissions. Injection of steam and water has the effect of increasing the thermal mass by dilution and thereby reducing the peak temperature in the flame zone. There is an additional benefit of absorbing the latent heat of vaporization from the flame zone when water injection is utilized. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.[9]

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[6] General Electric Power Systems, GER-4211, "Gas Turbine Emissions and Control", 03/2001
[7] 40 CFR 51, Appendix Y, Section IV.D.2
[8] 40 CFR 51, Appendix Y, Section IV.D.1
[9] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"

Water/steam injection was not identified in this review of RBLC as a potential control of NO_X emissions from natural gas-fired combustion turbines; however, AP-42 Section 3.1 does list water/steam injection as an available control technique for gas turbines.[10]

However, communications with GE have indicated that water/steam injection is not currently available for the Model A turbines located at Pecos River. The technology has never been retrofit for units older than the Model J, and there is no way to determine what, if any, emissions reduction could be achieved through a retrofit. Furthermore, GE has indicated that they have since retired this control option and do not recommend water injection be installed to control emissions from any of their turbine units. As this technology has never been installed on any GE Model A turbine, there is no historical data to support that installation of these controls would result in significant reductions of NO_X emissions. For this reason, it has been determined that this control technology is infeasible for the turbines located at Pecos River.

2.2.5. Selective Catalytic Reduction Systems

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[11] The chemical reactions for this process are shown in the equations below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

An SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and an electronic control system. The electronic controls regulate the quantity of reagent injected as a function of turbine load, speed, and temperature, so NO_X emissions reductions can be achieved. The lifespan of the catalyst is primarily determined by poisoning of active sites by flue gas constituent, thermal sintering, or compacting, of active sited due to high temperatures in the reactor, fouling caused by ammonia-sulfur salts and particulate matter in the gas, and erosion due to high gas velocities.[12]

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as ammonia slip. Unreacted ammonia in the exhaust can form ammonium sulfates which may plug or corrode downstream equipment. As urea is an ammonia precursor, ammonia slip will occur regardless of the reagent employed. Ammonium sulfate-laden streams may blind the catalyst and may necessitate the application of a soot blower.[13]

In order for the SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 and 850 °F), dependent on the material of the catalyst. Exhaust gas temperatures greater than the upper limit will cause the NO_X and ammonia to pass through the catalyst unreacted.[14] The exhaust temperature of the turbines assessed here is approximately 580 °F.

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[10] Ibid.
[11] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
[12] Ibid.
[13] Ibid.
[14] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"

SCR is considered a technically feasible control option for the turbines located at Pecos River. SCR units typically achieve 65% to 90% NO_X reduction, dependent on the exhaust temperature and upstream NO_X concentration.[15]

[15] Ibid.

3. COST OF COMPLIANCE

EPNG has evaluated the costs of implementing the technically feasible control technologies as thoroughly as possible in the time provided to complete this assessment. These cost estimates are calculated according to the methods and recommendations in the EPA Air Pollution Control Cost Manual.[16] Cost effectiveness considerations for the turbines are discussed below, with costs summarized in Table 3.

Table 3. Cost Analysis Summary of Technically Feasible Control Options for Combustion Turbines

Control Equipment	Unit	SCR Capital Cost ($)	Building Modifications ($)	Total Annual Cost ($)*	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Selective Catalytic Reduction	A-01	3,802,798	2,500,000	656,640	36.0	18,252
	A-02	3,802,798	2,500,000	664,748	66.9	9,931
	A-03	3,802,798	2,500,000	662,707	61.0	10,858

*Total Annual Cost includes the annualized SCR capital and building modification costs, as well as the direct and indirect annual operating costs.

EPNG has selected to use the EPA Air Pollution Control Cost Spreadsheet for SCR to estimate the costs associated with implementing an SCR control system on the turbines at Pecos River. The estimate incorporates direct capital cost for equipment and vendor labor, direct annual costs (maintenance, operating labor, reagent cost, electricity cost, and catalyst cost), and indirect costs associated with EPNG's internal labor, overhead and capital recovery for the project.

In addition, there are site-specific space limitations that prevent the installation of the necessary equipment for this control method (i.e., SCR module and reagent storage systems). Based on the current configuration of the turbines, the exhaust system ducting would require significant modifications in order to install the catalyst. Specifically, the stack for each unit would need to be relocated and additional ducting would be required. At this time, EPNG believes that there is insufficient room within the existing building that houses the turbines to complete the necessary modifications and installation of the catalyst. The cost necessary to modify the turbine housing has been estimated by EPNG and is accounted for in this cost effectiveness calculation.

This cost estimate assumes that the SCR will reduce NO_X emissions with a 70% efficiency.[17] There is no historical data to support a higher control efficiency assumption. In addition, due to the age of the units and current availability of control equipment for them, it is assumed that there would be significant difficulties retrofitting each of these turbines with an SCR control. Therefore, a retrofit difficulty factor of 1.5 is used for this analysis.

These cost estimates have been developed based on the actual emissions from each unit assessed here, calculated using June 2016 stack test data for each unit and the actual hours of operation from the 2016 Emission Inventory submittal for Pecos River. The stack test data utilized for these calculations is included in Appendix C of this report and a copy of the EPA Air Pollution Control Cost Spreadsheet for each unit is included in Appendix D.

[16] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

[17] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

4. TIME NECESSARY FOR COMPLIANCE

The second factor in this analysis is the time necessary for compliance. Consideration of this factor involves estimating the time required for a source to implement a potential control measure. This information is provided here in order to advise the NMED of EPNG's projection of a reasonable compliance timeline based on the equipment and site-specific considerations that could affect the time necessary to comply.

EPNG estimates that approximately 36 months will be necessary to make the building modifications and install the SCR control equipment. Factors that have been considered for this anticipated timeline include project development, engineering, lead time to acquire the necessary materials, construction, and commissioning.

5. ENERGY AND NON-AIR ENVIRONMENTAL IMPACTS

This section addresses the potential energy and non-air environmental impacts that installation of the technically feasible control options poses on a source. The consideration of energy impacts involves assessing the impact of a control measure on the energy that is consumed by the source. Non-air environmental impacts are assessed based on the effect of the control on non-air environmental media. Some examples of non-air environmental impacts include water resource depletion, solid waste generation, increased noise and odor pollution, and increased land usage.

The implementation of SCR on the turbines at Pecos River would result in several energy and non-air impacts. The primary impact of this control would be a significant increase in energy consumption, which would be necessary to power the units. The estimated energy consumption for each unit is summarized in Table 4, and is based on the EPA Air Pollution Control Cost Manual.[18] The calculation for these values is included in Appendix E of this report. EPNG does not anticipate any issues with meeting this increased energy burden.

Table 4. Energy Consumption Analysis Summary

Unit	Annual Energy Consumption (MWh)
A-01	158.3
A-02	227.7
A-03	206.6
Total	592.6

In addition to the increased energy burden, there are several non-air environmental impacts associated with the handling and storage of the reagent used in the SCR system, typically ammonia or urea. Ammonia is a Toxic Air Pollutant (TAP) regulated under 20.2.72.502 NMAC with an occupational exposure limit (OEL) of 18 mg/m^3. In both soil and water, urea is hydrolyzed quickly to ammonia and carbon dioxide by urease, an extracellular enzyme that originates from microorganisms and plant roots.[19] Short-term inhalation exposure to high levels of ammonia in humans can cause irritation and serious burns in the mouth, lungs, and eyes. Chronic exposure to airborne ammonia can increase the risk of respiratory irritation, cough, wheezing, tightness in the chest, and impaired lung function in humans. Animal studies also suggest that exposure to high levels of ammonia in air may adversely affect other organs, such as the liver, kidney, and spleen.[20]

Unavoidable releases of ammonia could have significant and irreversible impacts on the living and physical environment affected. Storage and handling of urea or ammonia onsite would result in an increased risk to the health and safety of facility operators. Pecos River is a natural gas compressor station, which already maintains a high level of health and safety risk. EPNG considers any increase to this risk unacceptable.

[18] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

[19] U.S. EPA, EPA/635/R-10/005F, "Toxilogical Report of Urea", July 2011

[20] U.S. EPA, EPA/635/R-16/163Fc, "Toxicological Review of Ammonia Noncancer Inhalation: Executive Summary", September 2016

6. REMAINING USEFUL LIFE OF SOURCES

The anticipated remaining useful life of each source is addressed here for the NMED's consideration. The assessment of this factor involves estimating how long the sources analyzed will remain in operation and the lifetime of potential control measures, accounting for equipment and site-specific limitations.

40 CFR Part 51, Appendix Y includes guidance on the characterization of this factor, stating that the remaining useful life of a source will typically be longer than the useful life of the emission control system. Therefore, it is appropriate to annualize compliance costs based on the useful life of the control equipment, rather than the life of the source.[21]

Based on their current age and operating efficiency, it is estimated that the remaining useful life of the turbines will be longer than the SCR units. The turbines have operated for more than 65 years without any significant deterioration in operating efficiency; therefore, this analysis of the remaining useful life of the equipment will be based on the anticipated useful life of the SCR control device installed.

The estimated useful life of the SCR equipment is 20 years, based on default values from the EPA Air Pollution Control Cost Manual.[22]

[21] 40 CFR 51, Appendix Y, Section II.B.4.f

[22] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

7. SUMMARY & CONCLUSIONS

Based on a comprehensive review of the RBLC, available literature, and manufacturer's input of the available control technologies for the natural-gas fired turbines located at Pecos River, EPNG has determined that SCR is the only technically feasible control option for these units. The cost of compliance to install SCR controls on each of these units has been estimated based on the EPA Air Pollution Control Cost Manual.[23] The estimated cost effectiveness and NO_X emission reduction for each unit are summarized in Table 5, below.

Table 5. Summary of Cost Effectiveness and NO_X Reduction for SCR Control of the Turbines

Control Equipment	Unit	NO_X Reduction (tpy)	Cost Effectiveness ($/ton)
Selective Catalytic Reduction	A-01	36.0	18,252
	A-02	66.9	9,931
	A-03	61.0	10,858

It is projected that the useful life of these units will be 20 years, based on the life expectancy of the SCR controls. The primary energy and non-air impacts from this control method will be increased energy consumption and health and safety risk. EPNG estimates that 36 months would be an achievable compliance timeline for this control.

[23] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

8. SUPPORTING DOCUMENTATION

Appendix A – RBLC Tables
Appendix B – June 2016 Stack Test Data
Appendix C – Cost Analysis Calculations
Appendix D – Energy Consumption Calculation

APPENDIX A – RBLC TABLES

RBLC Analysis for Natural Gas Fired Turbines – NO_X Control

	Control Technology	Good Combustion Technique	Improved Combustion Technology (Low-NO_X Combustors, Ultra-Low NO_X Combustors and other improved combustion technology)[a]	Water/Steam Injection[b]	Selective Catalytic Reduction (SCR)[c]
IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. Primary combustion occurs at lower temperatures under oxygen-deficient conditions. By following EPA's "Good Combustion Practices" guidance document, good combustion practices can be maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices the unit will operate as intended with the optimal NO_X emissions.	Low-NO_X burners employ multi-staged combustion to inhibit the formation of NO_X. Primary combustion occurs at lower temperatures under oxygen-deficient conditions; secondary combustion occurs in the presence of excess air. This category includes Improved Combustion Technology Lean Head End Liners for the GE turbines assessed here.	Injected water/steam acts as a heat sink, lowering combustion zone peak temperatures, resulting in a decrease in thermal NO_X.	A nitrogen-based reagent (e.g., ammonia, urea) is injected into the exhaust stream downstream of the combustion unit. The reagent reacts selectively with NO_X to produce molecular N_2 and water in a reactor vessel containing a metallic or ceramic catalyst.
	Other Considerations	N/A	N/A	Results in a small efficiency penalty but an increase in power output. May increase CO and VOC emissions. Not available in certain models.	Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as "ammonia slip." Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.
	RBLC Database Information	Included in RBLC for control of NO_X emissions from combustion turbines.	Included in RBLC for the control of NO_X emissions from combustion turbines.	Not included in RBLC for the control of NO_X emissions from combustion turbines; identified as a control option based on AP-42 Section 3.1.	Included in RBLC for the control of NO_X emissions from combustion turbines.
ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	Feasibility Discussion	Technically feasible.	Technically infeasible. This option is not available for the turbine model.	Technically infeasible. This option is not available for the turbine model.	Technically feasible.
RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	Base Case			65-90%

a. California EPA, Air Resources Board, "Section 311 - Non-Selective Catalytic Reduction and Other NO_X Controls," http://www.arb.ca.gov/cap/manuals/cntrldev/sncr_etc/311nscr.htm
b. U.S. EPA, AP-42 Section 3.1, "Stationary Gas Turbines"
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

RBLCID	FACILITY NAME	EPA REGION	PERMIT NUM	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	COST EFFECTIVENESS	INCREMENTAL COST EFFECTIVENESS	Cost Verified	DOLLAR YEAR USED IN COST ESTIMATES
AK-0083	KENAI NITROGEN OPERATIONS	10	AQ0083CPT06	Five (5) Natural Gas Fired Combustion Turbines	16.11	Natural Gas	37.6	MMBTU/H	Five (5) Natural Gas-Fired Solar Combustion Turbines rated at 37.6 MMBtu/hr each. Installed in 1976.	Nitrogen Oxides (NOx)	A	Selective Catalytic Reduction	0			0	0	N	
CA-1215	QUALCOMM INC.	9	2012--APP-002100	Cogeneration gas turbine	16.11	natural gas	4.37	MW	Manufacturer: Solar Turbines- Model: Mercury 50-6400R	Nitrogen Oxides (NOx)	A	SoLoNOx burner (Ultra lean Premix)	0			0	0	N	
LA-0331	CALCASIEU PASS LNG PROJECT	6	PDS-LA-805	Aeroderivative Simple Cycle Combustion Turbine	16.11	Natural Gas	263	MM BTU/h		Nitrogen Oxides (NOx)	B	Selective Catalytic Reduction (SCR), exclusive combustion of fuel gas, and good combustion practices.	0			0	0	N	
MI-0410	THETFORD GENERATING STATION	5	191-12	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	16.11	natural gas	171	MMBTU/H	Two natural gas fired simple cycle combustion turbines each with an electrical generator (nominal 13MW each; 171 MMBtu/hr heat input rating each). Each turbine is limited to 343 MMscf of natural gas per 12-month rolling time period as determined at the end of each calendar month. Both turbines combined are limited to 5.15 MMscf of natural gas each calendar day.	Nitrogen Oxides (NOx)	P	Dry low-NOx combustors	0			0	0	N	
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	5	185-15	FG-TURBINES	16.11	Natural gas	10504	HP	Five (5) simple cycle natural gas-fired combustion turbines (CTs) to drive compressors that will be used to transport natural gas through pipelines. The turbines are identified as EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, and EUTURBINE5 within the flexible group FGTURBINES. There shall be no more than a combined total of 5 events (startup or shutdown) per clock hour. The total number of startup events for all units combined shall not exceed 500 events per 12-month rolling time period. The total number of shutdown events for all units combined shall not exceed 500 events per 12-month rolling time period. The maximum nominal rating of each turbine shall not exceed 10,504 HP (ISO).	Nitrogen Oxides (NOx)	A	Dry ultra-low NOx burners	0			0	0	N	
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	5	185-15A	FGTURNBINES (5 Simple Cycle CTs: EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5]	16.11	Natural gas	10504	HP	Five simple cycle natural gas-fired combustion turbines (CTs) to drive compressors that will be used to transport natural gas through pipelines (EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5 in FGTURBINES). There shall be no more than a combined total of 5 events (startup or shutdown) per clock hour. The total number of startup events for all units combined shall not exceed 500 events per 12-month rolling time period. The total number of shutdown events for all units combined shall not exceed 500 events per 12-month rolling time period. The maximum nominal rating of each turbine shall not exceed 10,504 HP (ISO).	Nitrogen Oxides (NOx)	A	Dry ultra-low NOx burners.	0			0	0	N	
NV-0050	MGM MIRAGE	9	825	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	16.11	NATURAL GAS	4.6	MMBTU/H	THE TWO UNITS ARE IDENTICAL SOLAR MERCURY COMBUSTION GAS TURBINES FOR ELECTRIC POWER GENERATION. EACH UNIT IS RATED AT 4.6 MMBTU/HR, AND IS ALLOWED TO OPERATE 24 HOURS/DAY AND 8,760 HOURS/YEAR.	Nitrogen Oxides (NOx)	P	LEAN PRE-MIX TECHNOLOGY AND LIMITING THE FUEL TO NATURAL GAS ONLY	0.178	LB/MMBTU		0	0	N	
OK-0148	BUFFALO CREEK PROCESSING PLANT	6	2012-1026-C PSD	Small Combustion Turbines (&It;25MW)	16.11	Natural Gas	10179	Horsepower	Solar Taurus 70-10802S times 2.	Nitrogen Oxides (NOx)	P	Dry-Low NOx Combustion	0			0	0	N	
OK-0153	ROSE VALLEY PLANT	6	2012-1393-C PSD	TURBINES 5,443 HP SIEMENS SGT-200-2S	16.11	NATURAL GAS	9443	HP	THESE ARE TO BE LIKE-KIND TURBINES.	Nitrogen Oxides (NOx)	P	DRY LOW-NOx COMBUSTION.	0			0	0	N	
*PA-0314	BEECH HOLLOW	3	63-00922D	COMBUSTION TURBINE without DUCT BURNERS UNIT	16.11	Natural Gas	2433	MMBtu/hr	CEMS for NOx, CO	Nitrogen Oxides (NOx)	A	SCR	0			0	0	N	
TX-0642	SINTON COMPRESSOR STATION	6	PSDTX1304	Compression Turbine	16.11	natural gas	20000	hp	Two (2) 20,000 horsepower Solar Titan 130S turbines in natural gas pipeline compression service	Nitrogen Oxides (NOx)	P	Solar's SoLoNOx dry emission control technology	0			0	0	N	
TX-0685	GUADALUPE GENERATING STATION	6	106051 PSDTX1310	(2) simple cycle turbines	16.11	natural gas	190	MW	Four models are approved: GE7FA.03, GE7FA.04, GE7FA.05, or Siemens SW 5000FS. 383 MW to 454 MW total plant capacity.	Nitrogen Oxides (NOx)	B	DLN burners, limited operation	0			0	0	N	
*WI-0283	AFE, INC. â€"LCM PLANT	5	17-JIW-207	P90 â€" Natural Gas-Fired Emergency Generator	16.11	Natural Gas	9.51	mmBTU/hr	750 kW or 1,114 brake horsepower	Nitrogen Oxides (NOx)	P	Good Combustion Practices and the Use of Turbocharger and Aftercooler	0			0	0	N	
WY-0067	ECHO SPRINGS GAS PLANT	8	MD-7837	TURBINES S35-S36	16.11	NATURAL GAS	12555	HP	TWO (2) 12,555 HP SOLAR MARS 100-15000S TURBINES	Nitrogen Oxides (NOx)	N	SOLONOX	0			0	0	N	
WY-0067	ECHO SPRINGS GAS PLANT	8	MD-7837	TURBINE S34	16.11	NATURAL GAS	3856	HP	SOLAR CENTAUR 40-T4700S	Nitrogen Oxides (NOx)	N	SOLONOX	0			0	0	N	

APPENDIX B – EPNG TURBINE BEST PRACTICES PROCEDURES

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1. Scope

1.1. General

Historically, some “Best Practices” documents were developed to cover specific regions, pipelines, or other limited-scope situations. While such documents may not agree with all provisions of Company Operating and Maintenance (O&M) Procedures, they contain vital information and considerations that may prove useful to many users.

Best Practices documents are intended to *complement* Company O&M Procedures. As such, this procedure provides *recommendations* and *guidance* to supplement the Company and Code Requirements defined within O&M Procedures, Engineering Standards, and other Company Compliance Documents.

In all applications, Company O&M Procedures and Engineering Standards shall prevail as Company Requirements.

1.2. G.E. Gas Turbine Inspection/Maintenance Schedules

Regular analysis, inspection, and maintenance of G.E. gas turbines contribute to a reliable, efficient, and safe operation of the Company turbine fleet.

2. Recommendations

G.E. gas turbines should be maintained following the maintenance programs set forth below. These are minimum recommendations and should be adjusted for each location as operating conditions warrant.

A) Typically, the life-limiting components are in the hot section. Parameters affecting the schedules for inspection and repair or replacements are material erosion, including oxidation and corrosion, stress rupture, and fatigue. Each engine component will have different critical limits and may react differently to specific environments and/or deviation from the basic design condition. Therefore, each location should monitor the condition of their unit and take necessary actions to ensure a safe and reliable operation.

B) It is recommended that a start counter be installed on each unit and all full load trips be logged in order to ensure applicable maintenance scheduling. Repeated starts and trips from full load impose large thermal stresses on parts leading to an increased potential for Low Cycle Fatigue (LCF) failure. These high thermal stresses are common in most gas turbine materials because the alloying elements used to achieve material strength at high temperatures are the same ones that produce low thermal conductivity. Thus, it is important to account for all starts and trips on all units.

   Anything that can be done to reduce trips at full load will reduce the potential for component failures resulting from low cycle fatigue.

3. Procedure

A) General Electric Frame 3 and Frame 5 Turbines

   1) Every 800-1,200 Fired Hours Operated

      a. Take lube oil sample for laboratory analysis.

b. Check oil level in the oil sump. Verify that no oil is present in the skid sump vent line.

2) Every 8,000 Fired Hours Operated

a. Check controls and recalibrate if necessary.
b. Calibrate recycle valve positioner and ensure valve operates at required speed.

3) 8,000-11,000 E.H.O.* - Combustor Inspection

*For GE Frame 3 Turbines: E.H.O. = hours operated + (# of starts x 10) + (# of full load trips x 100) (A full load trip is any trip of the turbine when operating above 75% load.)

Combustor inspection should include:

a. Boroscope of blading, buckets, and nozzles
b. Inspection of the combustion liners
c. Inspection of the cowl caps
d. Inspection of the transition pieces
e. Inspection of the Axial Flow Compressor (AFC) and stator blading including the washing
f. Removal of fuel nozzles for cleaning and inspection for cracks/other defects
g. Check of igniters and flame detectors
h. Greasing all the auxiliary couplings
i. Repair of any maintenance items required
j. Inspect all tubing, hoses, and fittings.

4) 26,000-28,000 E.H.O.* - Hot Gas Path Inspection

*For GE Frame 3 Turbines: E.H.O. = hours operated + (# of starts x 10) + (# of full load trips x 100) (A full load trip is any trip of the turbine when operating above 75% load.)

Hot gas path inspection should include:

a. Inspection of the combustion liners
b. Inspection of the cowl caps
c. Inspection of the transition pieces
d. Inspection of the Axial Flow Compressor (AFC) and stator blading including the washing
e. Removal of the shell half
f. Inspection of the first stage nozzles
g. Check alignment from the turbine to compressor.
h. Grease all the auxiliary couplings.
i. Repair any maintenance items required.
j. The turbine should be cleaned and inspected for cracks, chips, hot spots, or other damage.
k. Damaged or defective parts will be repaired or replaced, as required.

5) Overhaul - 38,000 - 42,000 E.H.O. for units with composite wheels,

Overhaul - 48,000 - 50,000 E.H.O. for units with non-composite wheels.

Each Overhaul should include:

a. Inspection of the combustion liners
b. Inspection of the cowl caps
c. Inspection of the transition pieces
d. Inspection of the Axial Flow Compressor (AFC) and stator blading including the washing
e. Removal of the shell half
f. Inspection of the First stage nozzles
g. Removal of all the rotating assemblies
h. Inspection of the accessory gear section
i. Inspection of the load coupling
j. Grease all the auxiliary couplings.
k. Inspection of the Second Stage nozzles

l. Inspection of the starting means
m. Inspection of the high-speed coupling
n. Removal and inspection of the air and oil seals
o. Removal and inspection of all the bearings
p. Check alignment from the turbine to compressor.
q. Bump check compressor.
r. Calibrate all logic controls at major overhaul.

B) GE LM500 TURBINES

1) Weekly -

a. Check oil levels.
b. Check oil pressure.
c. Check engine air pressure (P-3).
d. Check for leaks (air, oil, etc.).
e. Check for signs of hot spots on case.
f. Check for excessive noises or vibrations.
g. Check air and oil filter differentials.
h. Check for loose bolts, fittings, etc.
i. Check control gauges and transmitters for leaks.

2) Every 1,000 - 1,200 Hours Operated -

a. Conduct a thorough visual inspection of outer parts.
b. Take lube oil sample for laboratory analysis.
c. Check fuel and start gas lines for leaks.
d. Change oil filters with high differential pressure.
e. Change air inlet pre-filters if oily.
f. Check package air inlet filters.
g. Check V.G. control cable for wear or slack.
h. Check lock-wires on bolts and nuts for breaks.
i. Check chip detectors in lube oil lines.

3) Every 7,000-8,000 Fired Hours Operated -

a. Boroscope hot and cold ends and gas compressor.
b. Pull fuel nozzles and check for wear.
c. Pull and inspect half of low pressure power turbine case.

4) Annual not to exceed 15 months -

a. Check calibrations on all transmitters.
b. Check calibrations on controls (speed, EGT, P-3, etc.).
c. Check calibrations on Woodward governor fuel slopes.
d. Check calibration of vibration and shutdown devices.
e. Check and test all safety shutdowns.
f. Calibrate recycle valve positioner and ensure valve operates at required speed.

5) Overhauls on LM500 turbines are to be conducted as needed, based on Boroscope inspections.

a. Calibrate all logic controls at major overhaul.

4. Documentation

Some Pipelines and related Field Staff use one or more of the following:

- MAXIMO as an activities scheduling utility
- COMET for Compressor Data tracking

- Other Legacy Forms and Data Logs

Until such time as these systems (MAXIMO, COMET, etc.) are superseded, the following information is provided for user reference:

MAXIMO PM

- GE Frame 3 & Frame 5 - Oil Analysis - Every 2 months NTE 75 days or 1200 Fired Operated Hours
- GE Frame 3 & Frame 5 – Controls Calibration
- GE Frame 3 & Frame 5 - Combustor Inspection - 8000 NTE 11,000 E.H.O.
- GE Frame 3 & Frame 5 - Hot Gas Path Inspection - 26,000 NTE 28,000 E.H.O.
- GE Frame 3 & Fame 5 - Major Overhaul (Composite Turbine Wheels) - 38,000 NTE 42,000 E.H.O.
- GE Frame 3 & Frame 5 - Major Overhaul (Non-Composite Turbine Wheels) - 48,000 NTE 50,000 E.H.O.
- GE LM500 - Weekly Inspection - Weekly
- GE LM500 - 1,000 Hour Inspection - 1,000 NTE 1,200 Fired Hours Operated
- GE LM500 - 7000 Hour Inspection - 7000 NTE 8000 Fired Hours Operated
- GE LM500 - Controls Calibration - 1 Year NTE 15 Months

Engine Oil Analysis Report - Vendor Form (Refer to **Best Practices COMP203-3 - Turbine Oil Analysis**)

- Retention - 1 Year Plus Current Year
- Retention Location - Station

Protective Device Check Gas Turbines – (COMP-0178)

- Retention – 1 Year Plus Current Year
- Retention Location - Station

Turbine Inspection Forms Workbook (Frame & Model Specific) - (COMP-2008 through COMP-2018), OR:
GE Combustion Liner Inspection Report - Vendor Form
GE Hot Gas Path Inspection Report - Vendor Form
GE Major Overhaul Inspection Report - Vendor Form

- Retention - Life of the Equipment
- Retention Location, Turbine Inspection Forms Workbook – Livelink
- Retention Location, G.E. Vendor Forms - Station

5. References

- **Best Practices COMP202-6 - Turbine Filter Replacement**
- **Best Practices COMP203-1 - Turbine Maintenance Analysis**
- **Best Practices COMP203-3 - Turbine Oil Analysis**
- **Best Practices COMP204-1 - Unit Protective Device Check - Turbine Engines**
- **Environmental, Health, and Safety Policy Manual**
- **O&M Procedures Manual**

APPENDIX C – JUNE 2016 STACK TEST DATA

SUMMARY OF TEST RESULTS PECOS RIVER STATION

Permit P129R2M1 – October 4, 2011

Pecos River Station unit S001 GE Model M3712R A S/N95025

Annual performance testing was performed on unit 1 exhaust for NOx, CO, and O2 on July 12, 2016. Maximum achievable load compliance consisted of three (20) twenty minute sampling events which were used to calculate the average for the emission values. These averages were then compared with the unit permitted limits to determine the performance status. **Based on the test results, unit S001 PASSED the Performance Test Audit**

Parameter	Measured	Permit	Status
Emission Load (% HP)	94.09	n/a	n/a
NOx (lb/hr)	20.63	53.10	PASS
NOx (TPY)	89.79	233	PASS
CO (lb/hr)	4.36	8.00	PASS
CO (TPY)	19.00	35	PASS

SUMMARY OF TEST RESULTS PECOS RIVER STATION

Permit P129R2M1 – October 4, 2011

Pecos River Station unit S002 GE Model M3712R A S/N95053

Annual performance testing was performed on unit 2 exhaust for NOx, CO, and O2 on June 21, 2016. Maximum achievable load compliance consisted of three (20) twenty minute sampling events which were used to calculate the average for the emission values. These averages were then compared with the unit permitted limits to determine the performance status. **Based on the test results, unit S002 PASSED the Performance Test Audit**

Parameter	Measured	Permit	Status
Emission Load (% HP)	105.62	n/a	n/a
NOx (lb/hr)	26.69	53.10	PASS
NOx (TPY)	116.21	233	PASS
CO (lb/hr)	3.67	8.00	PASS
CO (TPY)	15.97	35	PASS

SUMMARY OF TEST RESULTS PECOS RIVER STATION

Permit P129R2M1 – October 4, 2011

Pecos River Station unit S003 GE Model M3712R A S/N95055

Quarterly performance testing was performed on unit 3 exhaust for NOx, CO, and O2 on June 21, 2016. Maximum achievable load compliance consisted of three (20) twenty minute sampling events which were used to calculate the average for the emission values. These averages were then compared with the unit permitted limits to determine the performance status. **Based on the test results, unit S003 PASSED the Performance Test Audit**

Parameter	Measured	Permit	Status
Emission Load (% HP)	91.00	n/a	n/a
NOx (lb/hr)	26.82	53.10	PASS
NOx (TPY)	116.80	233	PASS
CO (lb/hr)	4.11	8.00	PASS
CO (TPY)	17.87	35	PASS

APPENDIX D – COST ANALYSIS CALCULATIONS

El Paso Natural Gas Company, LLC

Pecos River Compressor Station

Turbine Cost Analysis Interest Rate: 5.50%

All Units Period (yrs): 20

Control Equipment	Unit	SCR Capital Cost ($)	Building Modification ($)	Total Annual Cost* ($)	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Selective Catalytic Reduction (SCR)	A-01	3,802,798	2,500,000	656,640	36.0	18,252
	A-02	3,802,798	2,500,000	664,748	66.9	9,931
	A-03	3,802,798	2,500,000	662,707	61.0	10,858

* Total Annual Cost includes the annualized capital cost as well as the direct and indirect annual operating costs.

El Paso Natural Gas Company, LLC

Pecos River Compressor Station

GE Model M3712R Turbine	Interest Rate:	5.50%	
A-01	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:	20.63 lb/hr		<-- June 2016 stack test results
NO_x tpy:	51.39 tpy		<-- Calculated using 2016 stack test and 2016 EI actual operating hours.
SCR			
NO_x Reduction:	70%		<-- Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032
NO_x lb/hr:	6.19 lb/hr		
NO_x tpy:	15.42 tpy		
Turbine Housing Reconfiguration	$ 2,500,000		<-- Estimated cost from EPNG
SCR Capital Investment	$ 3,802,798		<-- EPA Cost Control Spreadsheet
Total Capital Investment	$ 6,302,798		
Annualized TCI:	$ 527,414		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 129,227		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$ 656,640		
Emissions Reduction:	36.0 tpy		
Cost Effectiveness:	**$ 18,252.11**	**$/ton**	

Unit A-01: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new turbine or retrofit of an existing turbine?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?[1]	61.8	MMBtu/hour
What is the higher heating value (HHV) of the fuel?[1,2]	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	298,551,855	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 2900 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the Cost Estimate tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Fuel consumption adjusted for actual 2016 operating hours, per the 2016 Emission Inventory submittal (524.9 MMscf/yr * 4982.50/8760 hours/year = 298.55 MMscf/yr)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the turbine operates (tplant)	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR[2]	0.3338	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR[3]	0.1001	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})[4]	35103.70	ft^3/min-MMBtu/hour

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Permitted NO_x emission rate / permitted heat input (53.1 lb/hr / 61.8 Mmbtu/hr)

[3] Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032; 70% efficiency

[4] Calculated based on the estimated actual annual fuel consumption and maximum heat input rate.

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh			* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

Unit A-01: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	61.8	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	525,090,204	scf/Year	
Actual Annual fuel consumption (Mactual) =		298,551,855	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.569	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4981	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	14.44	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	35.96	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.88		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,075,900	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	9,383.94	/hour	
Residence Time	1/V_{space}	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.11		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia	
Retrofit Factor (RF)	Retrofit to existing turbine	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1), where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	221.22	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,162	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	2,487	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	49.9	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	6	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	19	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	900	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	31.78	kW

Unit A-01: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Turbines

For Oil and Natural Gas-Fired Utility turbines between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility turbines >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial turbines between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial turbines >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$3,802,798	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$126,370 in 2018 dollars
Indirect Annual Costs (IDAC) =	$321,150 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$447,521 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$19,014 in 2018 dollars
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600 in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$3,773 in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$10,699 in 2018 dollars
Annual Catalyst Replacement Cost =		$5,284 in 2018 dollars
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	
Direct Annual Cost =		$126,370 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,856 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$318,294 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$321,150 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$447,521 per year in 2018 dollars
NOx Removed =	36.0 tons/year

El Paso Natural Gas Company, LLC

Pecos River Compressor Station

GE Model M3712R Turbine	Interest Rate:	5.50%	
A-02	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:	26.69 lb/hr		<-- June 2016 stack test results
NO_x tpy:	95.62 tpy		<-- Calculated using 2016 stack test and 2016 EI actual operating hours.
SCR			
NO_x Reduction:	70%		<-- Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032
NO_x lb/hr:	8.01 lb/hr		
NO_x tpy:	28.69 tpy		
Turbine Housing Reconfiguration	$ 2,500,000		<-- Estimated cost from EPNG
SCR Capital Investment	$ 3,802,798		<-- EPA Cost Control Spreadsheet
Total Capital Investment	$ 6,302,798		
Annualized TCI:	$ 527,414		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 137,334		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$ 664,748		
Emissions Reduction:	66.9 tpy		
Cost Effectiveness:	**$ 9,931.02**	**$/ton**	

Unit A-02: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new turbine or retrofit of an existing turbine?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?[1]	61.8	MMBtu/hour
What is the higher heating value (HHV) of the fuel?[1,2]	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	429,357,414	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 2900 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the Cost Estimate tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Fuel consumption adjusted for actual 2016 operating hours, per the 2016 Emission Inventory submittal (524.9 MMscf/yr * 7165.5/8760 hours/year = 429.3 MMscf/yr)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days	Number of SCR reactor chambers (n_{scr})	1
Number of days the turbine operates (tplant)	365	days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR[2]	0.4319	lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR[3]	0.1296	lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050		Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.			Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours		
Estimated SCR equipment life	20	Years*	Gas temperature at the SCR inlet (T)	650 °F
* For industrial turbines, the typical equipment life is between 20 and 25 years.			Base case fuel gas volumetric flow rate factor (Q_{fuel})[4]	50483.81 ft^3/min-MMBtu/hour
Concentration of reagent as stored (C_{stored})	29	percent*		
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*		
Number of days reagent is stored ($t_{storage}$)	14	days		

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Permitted NO_x emission rate / permitted heat input (53.1 lb/hr / 61.8 Mmbtu/hr)

[3] Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032; 70% efficiency

[4] Calculated based on the estimated actual annual fuel consumption and maximum heat input rate.

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh			* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

Unit A-02: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	62	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	525,090,204	scf/Year	
Actual Annual fuel consumption (Mactual) =		429,357,414	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.818	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7163	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	18.68	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	66.91	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.88		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,985,421	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	13,066.96	/hour	
Residence Time	1/V_{space}	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.11		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia	
Retrofit Factor (RF)	Retrofit to existing turbine	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1), where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	228.47	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	3,110	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	3,576	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	59.8	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	7	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	25	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,200	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	31.78	kW

Unit A-02: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Turbines

For Oil and Natural Gas-Fired Utility turbines between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility turbines >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial turbines between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial turbines >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$3,802,798	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$134,478 in 2018 dollars
Indirect Annual Costs (IDAC) =	$321,150 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$455,628 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$19,014 in 2018 dollars
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600 in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$7,019 in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$15,387 in 2018 dollars
Annual Catalyst Replacement Cost =		$5,458 in 2018 dollars
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	
Direct Annual Cost =		$134,478 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,856 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$318,294 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$321,150 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$455,628 per year in 2018 dollars
NOx Removed =	66.9 tons/year
Cost Effectiveness =	$6,809.34 per ton of NOx removed in 2018 dollars

El Paso Natural Gas Company, LLC

Pecos River Compressor Station

GE Model M3712R Turbine	Interest Rate:	5.50%	
A-03	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_X lb/hr:	26.82 lb/hr		<-- June 2016 stack test results
NO_x tpy:	87.19 tpy		<-- Calculated using 2016 stack test and 2016 EI actual operating hours.
SCR			
NO_X Reduction:	70%		<-- Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032
NO_X lb/hr:	8.05 lb/hr		
NO_X tpy:	26.16 tpy		
Turbine Housing Reconfiguration	$ 2,500,000		<-- Estimated cost from EPNG
SCR Capital Investment	$ 3,802,798		<-- EPA Cost Control Spreadsheet
Total Capital Investment	$ 6,302,798		
Annualized TCI:	$ 527,414		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 135,293		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$ 662,707		
Emissions Reduction:	61.0 tpy		
Cost Effectiveness:	**$ 10,858.37**	**$/ton**	

Unit A-03: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new turbine or retrofit of an existing turbine?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?[1]	61.8	MMBtu/hour
What is the higher heating value (HHV) of the fuel?[1,2]	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	389,585,454	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 2900 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the Cost Estimate tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Fuel consumption adjusted for actual 2016 operating hours, per the 2016 Emission Inventory submittal (524.9 MMscf/yr * 6501.75/8760 hours/year = 389.6 MMscf/yr)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the turbine operates (tplant)	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR[2]	0.4340 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR[3]	0.1302 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours		
Estimated SCR equipment life	20 Years*	Gas temperature at the SCR inlet (T)	650 °F
* For industrial turbines, the typical equipment life is between 20 and 25 years.		Base case fuel gas volumetric flow rate factor (Q_{fuel})[4]	45807.42 ft^3/min-MMBtu/hour
Concentration of reagent as stored (C_{stored})	29 percent*		
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*		
Number of days reagent is stored ($t_{storage}$)	14 days		

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Permitted NO_x emission rate / permitted heat input (53.1 lb/hr / 61.8 Mmbtu/hr)

[3] Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032; 70% efficiency

[4] Calculated based on the estimated actual annual fuel consumption and maximum heat input rate.

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh			* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

Unit A-03: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	62	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	525,090,204	scf/Year	
Actual Annual fuel consumption (Mactual) =		389,585,454	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.742	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6499	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	18.77	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	61.01	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.88		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,708,877	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	11,848.48	/hour	
Residence Time	1/V_{space}	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.11		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia	
Retrofit Factor (RF)	Retrofit to existing turbine	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1), where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	228.63	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,822	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	3,245	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	57.0	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	7	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	25	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,200	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	31.78	kW

Unit A-03: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Turbines

For Oil and Natural Gas-Fired Utility turbines between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility turbines >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial turbines between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial turbines >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$3,802,798	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$132,437 in 2018 dollars
Indirect Annual Costs (IDAC) =	$321,150 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$453,588 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$19,014 in 2018 dollars
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600 in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$6,400 in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$13,962 in 2018 dollars
Annual Catalyst Replacement Cost =		$5,461 in 2018 dollars
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	
Direct Annual Cost =		$132,437 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,856 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$318,294 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$321,150 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$453,588 per year in 2018 dollars
NOx Removed =	61.0 tons/year

APPENDIX E – ENERGY CONSUMPTION CALCULATION

El Paso Natural Gas Company, LLC

Pecos River Compressor Station

SCR Energy Usage Calculation

Unit: A-01

Equation:	Electricity Consumption, kW =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$			Source: EPA Cost Spreadsheet
Where:	A =	0.1 x QB			EPA Cost Spreadsheet for industrial turbines
	QB =	61.8	MMBTU/hr		Maximum Annual Heat Input Rate
	CoalF =	1.0			EPA Cost Spreadsheet value for Oil and Natural Gas
	Heat Rate Factor (HRF) =	NPHR / 10			
	Net Plant Heat Input Rate (NPHR) =	8.2	MMBtu/MW		Default EPA Cost spreadsheet value
Calculation:	HRF =	0.82			
	A =	6.18			
	Unit A-01 2016 Operating hours =	4982.5	hours		2016 EI Submittal
	Electricity Consumption =	31.8	kW		
	Annual Electricity Consumption =	158.3	MWh/yr		

El Paso Natural Gas Company, LLC

Pecos River Compressor Station

SCR Energy Usage Calculation

Unit: A-02

Equation:	Electricity Consumption, kW =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$			Source: EPA Cost Spreadsheet
Where:	A =	0.1 x QB			EPA Cost Spreadsheet for industrial turbines
	QB =	61.8	MMBTU/hr		Maximum Annual Heat Input Rate
	CoalF =	1.0			EPA Cost Spreadsheet value for Oil and Natural Gas
	Heat Rate Factor (HRF) =	NPHR / 10			
	Net Plant Heat Input Rate (NPHR) =	8.2	MMBtu/MW		Default EPA Cost spreadsheet value
Calculation:	HRF =	0.82			
	A =	6.18			
	Unit A-02 2016 Operating hours =	7165.5	hours		2016 EI Submittal
	Electricity Consumption =	31.8	kW		
	Annual Electricity Consumption =	227.7	MWh/yr		

El Paso Natural Gas Company, LLC

Pecos River Compressor Station

SCR Energy Usage Calculation

Unit: A-03

Equation:	Electricity Consumption, kW =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$			Source: EPA Cost Spreadsheet
Where:	A =	0.1 x QB			EPA Cost Spreadsheet for industrial turbines
	QB =	61.8	MMBTU/hr		Maximum Annual Heat Input Rate
	CoalF =	1.0			EPA Cost Spreadsheet value for Oil and Natural Gas
	Heat Rate Factor (HRF) =	NPHR / 10			
	Net Plant Heat Input Rate (NPHR) =	8.2	MMBtu/MW		Default EPA Cost spreadsheet value
Calculation:	HRF =	0.82			
	A =	6.18			
	Unit A-03 2016 Operating hours =	6501.75	hours		2016 EI Submittal
	Electricity Consumption =	31.8	kW		
	Annual Electricity Consumption =	206.6	MWh/yr		

El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

February 14, 2020

Mr. Mark Jones
Mr. Kerwin Singleton
NMED Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

RE: El Paso Natural Gas LLC - Pecos River Compressor Station
Regional Haze Four-factor Analysis December 23, 2019 Request for Additional Information

Dear Mr. Jones and Mr. Singleton:

This letter addresses the additional information request received on December 23, 2019 regarding the El Paso Natural Gas (EPNG) - Pecos River Compressor Station Four-Factor Analysis report. For the Pecos River Compressor Station there were a total of seven item requests pertaining to the assessment for the turbines, units A-01, A-02, and A-03. Please see the responses for each item request below.

1. *Provide details of the training curriculum and schedule for employees that ensure Good Combustion Practices utilized continue to be implemented at the plant. Clarify whether these best practices are fully optimized or conform to permit conditions alone.*

   Pecos River complies with the routine maintenance schedule pursuant to A205.B in Title V Permit No. P129R3. Pecos River complies with periodic testing pursuant to A205.A in order to monitor NO_X and CO emissions. Standard operating procedures and maintenance practices have been developed based on manufacturer's recommendations to keep the equipment in operating condition.

   Additionally, each employee has an Operator Qualification (OQ) Checklist that is completed and tracked in the OQ system. Operators are paired with other operators and work as trainees until they are deemed qualified on the piece of equipment and operation at the site. During the training period, they are exposed to station operations, responding to call outs with operators, station shutdowns, and purging and pressurizing stations. This training period lasts on average about one (1) year. Attached is a sample OQ qualification checklist used to track employee training (Attachment 1).

2. *Provide documentation of your communications with GE that supports the conclusion that Lean Head End Liner, improved combustion technology and water injection is not technically feasible for these units.*

   Please see Attachments 2 and 3. Per Thomas Hadden, Outage Performance Manager at GE/Baker Hughes, due to the age of the units (original construction in the 1950s), there was no technology that had been developed to improve emissions on the units. GE recommended either performing engineering studies in order to determine the potential emissions improvement for emissions, or upgrade the units from an A model to an F/J model in order to subsequently install emissions controls on the units.

3. *Provide the documentation to support El Paso Natural Gas's (EPNG's) cost estimates for building modifications required to install and house a SCR system.*

   The proposed cost was projected by the EPNG Engineering Department based on similar historical projects. The total estimated cost included mobilization, crane and other rental equipment, removal of existing equipment (including modifications to the building skin/roof), excavations and new foundations, backfill, and demobilization. No formal documentation was compiled to support this estimate.

4. *Please expand on the difficulties that may result due to the age of equipment and the availability of control equipment that led to using a retrofit difficulty factor of 1.5.*

   Based on conversations with the manufacturer, there appears to have been minimal market demand for control technology for these older model turbines. The 1.5 difficulty factor is used because it is anticipated that the project would require an engineering study prior to supply of the control, in addition to physical adjustments to the unit to accommodate the installation. The manufacturer has not been available to support this assessment, however. Therefore, the cost of compliance calculations have been update to utilize the default 1.0 difficulty factor. The updated cost of compliance for each unit is shown below.

Unit	Cost Effectiveness ($/ton)
A-01	24,607.04
A-02	9,491.17
A-03	9,974.19

5. *Provide a discussion regarding the varying operating hours across the three units and compare 2016 operating hours to the unit's five year average (i.e., 2014-2018) to evaluate if this is a representative scenario for estimating cost of compliance.*

   The varying operating hours across the three units and five years is due to fluctuations in production and market demand. Hours of operation are certificated by the U.S. Federal Energy Regulatory Commission (FERC) to ensure effective operation of the facility to meet customer demands. EPNG must maintain the permitted loads and operating hours for the units in order to effectively operate and satisfy supply contracts in place.

   The operating hours for each unit from 2014 to 2018 are shown below.

Operating Hours Per Year			
Yr/Unit	A-01	A-02	A-03
2014	6,920.92	5,983.92	7126.67
2015	5,602.33	4,018.83	5585.25
2016	4,982.50	7,165.50	6501.75
2017	754.75	7,916.25	7693.25
2018	5,323.25	3,813.75	5,031.50

Based on guidance received from the NMED in email correspondence on September 13, 2019, the original Four Factor Analysis was submitted using actual emissions from 2016 as a representative year for emissions and utilization for units A-01, A-02, and A-03.

As discussed with Mark Jones of the NMED on February 12, 2020 (Attachment 4), EPNG used an averaged 2016-2018 utilization and emissions to estimate cost effectiveness of various control technologies instead using 2016 as a sample year. Accordingly, EPNG hereby provides updated cost estimates based on the updated 2016-2018 average. Taking an average same over three years is more representative than a single year because unit utilization can be

6. *Provide a discussion explaining the difference between the emissions used to calculate costs (i.e., 2016 stack test data and operating hours) and the actual emissions reported to the department in 2016. The cost calculations use NOX emissions of 51.39 tons/year (tpy), 95.62 tpy, and 87.19 tpy whereas NOx emission were reported to NMED as 132.29 tpy, 190.24 tpy, and 172.62 tpy.*

   The cost estimates provided with the four-factor analysis are estimated based on the actual NO_x emissions from each unit assessed here, calculated using the June 2016 stack test data provided for each unit and the actual hours of operation from the 2016 Emission Inventory submittal for Pecos River.

   The NO_x emissions reported to the department in the 2016 Annual Emission Inventory submittal were calculated based on the permitted emission rate of the units. 2016 Annual Emission Inventory emissions appear to have been overestimated, based on the stack test data available.

   Subsequently, with the decision to use the 2016-2018 average for cost estimation analysis, the emissions calculations used from 2017 and 2018 were also updated based on stack test data rather than PTE emissions factors.

7. *Provide the electronic spreadsheets used for control technology cost calculations and annual energy consumption.*

   The electronic spreadsheet is attached (Attachment 5).

If you have any other questions, please do not hesitate to reach me at 713-420-1841 or via email at Zainab_Naqvi@kindermorgan.com.

Sincerely,

Zainab Naqvi
Air Permitting and Compliance
Kinder Morgan

Attachment 1

OPERATOR QUALIFICATION
Appendix G
COVERED TASK ASSIGNMENTS - GAS
Revised 3/23/2017

Employee Name:	EE Number:	Date:
Supervisor's Name:	Region/Location:	
Date Discussed with Employee:	***Supervisor's Signature***	

Submit this form with assigned covered tasks checked in the *Yes* column to your Regional OQ Coordinator.

CT #	Covered Task Title	Yes
01.01.01	Abnormal Operating Conditions	☐
02.01.01	Gas Detection & Alarm System Maintenance & Performance Test	☐
02.02.01	Isolation of Compressor Units	☐
02.03.01	Compressor Station Inspection & Testing of Remote Control Shutdown Devices	☐
03.01.01	Operating Compressor Units: Remote	☐
03.01.02	Operating Compressor Units: Manual	☐
03.02.01	Shutting Down Compressor Units: Remote	☐
03.02.02	Shutting Down Compressor Units: Manual	☐
03.03.01	Starting Compressor Units: Remote	☐
03.03.02	Starting Compressor Units: Manual	☐
04.01.01	Measure Damage on Installed Pipe and Components	☐
04.01.02	Corrosion Monitoring – Atmospheric, External, and Internal: Offshore Pipelines	☐
04.01.03	Visual Inspection of Buried Pipe and Components When Exposed	☐
04.01.04	Visual Inspection of Internal Surface of Pipe	☐
04.01.05	Visual Inspection for External/Atmospheric Corrosion (effective 6/30/17)	☐
04.01.06	Insert and Remove Coupons/Probes for Internal Corrosion Monitoring	☐
04.01.07	Nondestructive Testing – Magnetic Particle Testing of Pipe	☐
04.02.01	Coating Maintenance /Application and Repair – Sprayed, Brushed, or Rolled	☐
04.02.02	Coating Maintenance/Repair – Wrapped	☐

CT #	Covered Task Title	Yes
05.01.01	Cathodic Protection System Maintenance: Rectifiers	☐
05.01.02	Cathodic Protection System Maintenance: Electrical Isolation	☐
05.01.03	Cathodic Protection System Maintenance: Anodes, Anode Ground Beds, & AC Voltage Mitigation (task name change)	☐
05.01.04	Inspect or Test Cathodic Protection Bonds (task name change)	☐
05.01.05	Cathodic Protection System Maintenance: Reverse Current Switches	☐
05.01.06	Cathodic Protection System Maintenance: Automatic Potential Controlled Protection Systems	☐
05.01.07	Cathodic Protection System Maintenance: AC Voltage Mitigation System	☐
05.01.08	Cathodic Protection: Read Rectifier (effective 5/1/17)	☐
05.02.01	Cathodic Protection Systems – Electrical Connections	☐
05.03.01	Cathodic Protection System Testing: Test Stations	☐
05.03.02	Cathodic Protection System Testing: Pipe to Soil	☐
06.01.01	Indirect Inspection: Close Interval Survey	☐
06.01.02	Indirect Inspection: Direct Current Voltage Gradient (DCVG) Survey	☐
06.01.03	Indirect Inspection: Voltage Gradient (ACVG) Survey	☐
06.01.04	Indirect Inspection: AC Current Attenuation (ACCA or PCM) Survey	☐
07.01.01	Locating, Installing & Protecting Customer Meters & Regulators: Residential & Small Commercial	☐
07.01.02	Locating, Installing & Protecting Customer Meters & Regulators: Large Commercial	☐
07.02.01	Customer Pressure Regulating, Limiting & Relief Device: Residential & Small Commercial	☐
07.02.02	Customer Pressure Regulating, Limiting & Relief Device: Large Commercial & Industrial	☐
08.01.01	Locating Pipelines	☐
08.02.01	Damage Prevention During Excavation Activities	☐
09.01.01	System Patrolling	☐
10.01.01	Plastic Pipe – Electrofusion: Couplings	☐
10.01.02	Plastic Pipe – Electrofusion: Sidewall	☐
10.02.01	Plastic Pipe – Butt Heat Fusion	☐
10.03.01	Plastic Pipe – Sidewall Heat Fusion	☐
10.04.01	Mechanical Joints: Stab Fittings	☐

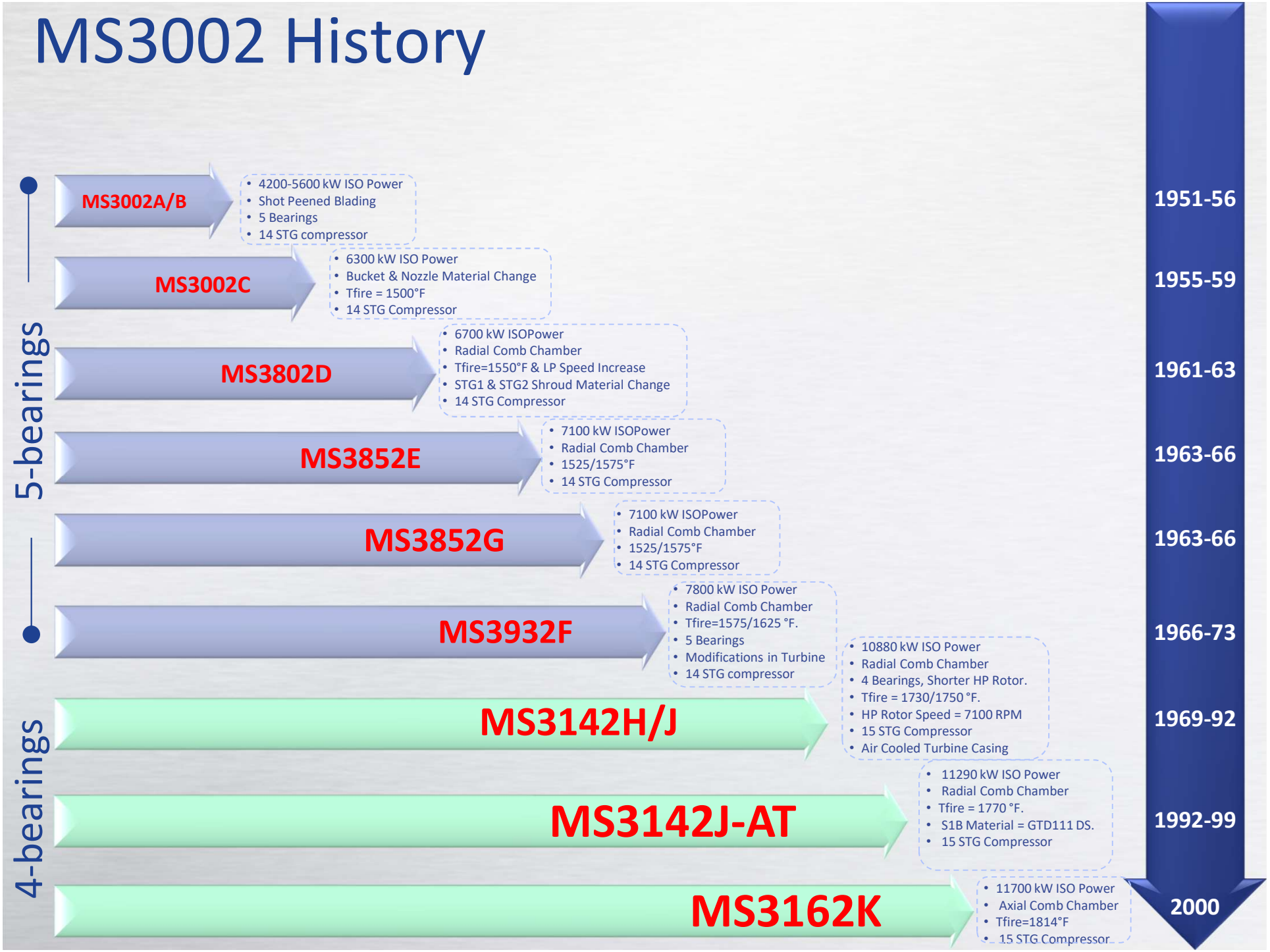
CT #	Covered Task Title	Yes
10.04.02	Mechanical Joints: Compression Couplings 2” & Less	☐
10.04.03	Mechanical Joints: Compression Couplings Greater Than 2”	☐
10.05.01	Joining of Pipe - Flange Assembly	☐
10.05.02	Joining of Pipe/Tubing – Threaded Fittings	☐
10.07.01	Solvent Cement Joints	☐
11.01.01	Direct/Inspect In-service Pipeline Lowering	☐
11.02.01	Detect/Inhibit/Mitigate Pipeline Hydrate Formation in Pipeline	☐
12.01.01	Leakage Survey: Walking	☐
12.01.02	Leakage Survey: Mobile	☐
12.02.01	Outside Leakage Investigation, Pinpointing and Grading	☐
12.03.01	Inside Gas Leakage Investigation	☐
13.01.01	Leak & Strength Test – Service Lines, Mains & Transmission Lines: Gaseous: Test Pressures < = 100 psi	☐
13.01.02	Leak & Strength Test – Service Lines, Mains & Transmission Lines: Gaseous: Test Pressures $\geq$ 100 psi	☐
13.01.03	Leak & Strength Test – Service Lines, Mains & Transmission Lines: Hydrostatic Test	☐
13.01.04	Leak & Strength Test – Service Lines, Mains & Transmission Lines: Test at Operation Pressure	☐
14.01.01	Abandonment or Inactivation of Facilities	☐
14.02.01	Backfilling	☐
14.03.01	Installation of Steel Pipe – Field Bends	☐
14.04.01	Casing Vents and Seals	☐
14.05.01	Underground Clearances	☐
14.06.01	Installation of Plastic Pipe: Direct Burial	☐
14.06.02	Installation of Plastic Pipe: Boring	☐
14.06.03	Installation of Plastic Pipe: Plowing/Planting	☐
14.06.04	Installation of Plastic Pipe: Plowing/Pull-In	☐
14.06.05	Installation of Plastic Pipe: Above Ground	☐
14.06.06	Installation of Plastic Pipe: Insertion	☐
14.07.01	Installation of Steel Pipe: Direct Burial	☐
14.07.02	Installation of Steel Pipe: Boring	☐
14.07.03	Installation of Steel Pipe: Plowing/Pull-In	☐
14.07.04	Installation of Steel Pipe: Above Ground	☐

CT #	Covered Task Title	Yes
14.07.05	Installation of Steel Pipe: Insertion	☐
14.08.01	Cover – Service Lines, Mains & Transmission Lines	☐
14.08.02	Cover – Offshore Pipelines	☐
14.09.01	Inspection: Compliance with Procedures & Standards	☐
14.09.02	Inspection: Inspection of Materials	☐
14.10.01	Line Markers	☐
14.11.02	Pipeline Shutdown, Startup or Pressure Change: Stopple Fitting	☐
14.11.03	Pipeline Shutdown, Startup or Pressure Change: Operating Identified Valve(s)	☐
14.11.04	Pipeline Shutdown, Startup or Pressure Change: Method(s) Required for Other Pipe Materials	☐
14.11.05	Launching and Receiving Internal Devices	☐
14.12.01	Protection from Hazards	☐
14.13.01	Protection When Minimum Cover Not Met	☐
14.14.01	Purging: Large Volume, i.e. Segment of Main or Transmission Line, etc.	☐
14.14.02	Purging: Small Volume, i.e. Service Line, Short Pipeline Segments, Compressor, Component, etc.	☐
14.15.01	Uprating: Reinforce or Anchor Offsets, Bends and Dead Ends – Longitudinal Straps	☐
14.15.02	Uprating: Reinforce or Anchor Offsets, Bends and Dead Ends – Anchoring & Buttressing	☐
14.16.01	Installation of Steel Pipe – Repair of Imperfections or Damage: Grinding	☐
14.18.01	Support, Expansion Joint and Anchor Maintenance – Exposed Pipeline	☐
14.19.01	Tapping Steel and Plastic Pipe: Manual (Self-Tapping)	☐
14.19.02	Tapping Steel and Plastic Pipe: Mechanical Tapping Equipment	☐
14.20.01	DOT Inspection of Valves	☐
14.20.02	Repair Valves	☐
14.21.01	Segment Removal	☐
14.22.01	Leak Clamps & Sleeves: Bolt-On Type	☐
14.22.02	Leak Clamps & Sleeves: Composite Sleeve (Clock Spring)	☐
15.01.01	Odorization – Mains & Transmission Lines: Periodic Sampling	☐
15.01.02	Odorization – Mains & Transmission Lines: Odorizer Maintenance	☐
16.01.01	Gas Quality: Operate/Test/Maintain Carbon Dioxide (CO2) Analyzers	☐
16.01.02	Gas Quality: Maintain/Service Chromatographs	☐
16.01.03	Gas Quality: Operate/Test/Maintain Oxygen (O2) Analyzers	☐
16.01.04	Gas Quality: Operate/Test/Maintain Sulfur Analyzers	☐

CT #	Covered Task Title	Yes
16.01.05	Gas Quality: Operate/Test/Maintain Moisture Analyzers	☐
16.01.07	Gas Quality: Operate & Maintain Gas Samplers	☐
16.01.08	Gas Quality: Troubleshoot/Repair Chromatographs	☐
16.01.09	Gas Quality: Troubleshoot & Repair Sulfur Analyzers	☐
16.01.10	Gas Quality: Troubleshoot/Repair Moisture Analyzers	☐
16.01.11	Gas Quality: Troubleshoot/Repair Carbon Dioxide (CO2) Analyzers	☐
16.01.12	Gas Quality: Troubleshoot/Repair Oxygen (O2) Analyzers	☐
18.01.01	Overpressure Safety Devices – Inspect, Test, and Calibrate Relief Valves	☐
18.01.02	Pressure Limiting Devices – Inspect, Test and Calibrate	☐
18.02.01	Vault Maintenance	☐
20.01.01	Service Line Replacement	☐
20.01.02	Service Line Replacement: Underground Service Entrance (Prerequisite 20.01.01)	☐
20.03.01	Service Lines Not in Use and Service Discontinuance	☐
24.01.01	Welding Process	☐
24.02.01	Visual Inspection of Welds	☐
24.03.01	Nondestructive Testing of Welds	☐
24.04.01	Miter Joints	☐
25.01.01	Dehydration: Operate/Maintain Liquid Knock-out	☐
25.01.02	Dehydration: Maintain/Repair Gas Fired Dehydration System Controls	☐
25.01.03	Dehydration: Operate/Maintain Gas Dehydration System	☐
25.01.04	Dehydration: Start-up/Shutdown of Dehydration System	☐
25.01.05	Dehydration: Troubleshoot/Repair Gas Dehydration System	☐
25.01.06	Gas Treatment: Read/Verify/Maintain Operating Parameters for Gas Processing/Amine System	☐
25.01.07	Gas Treatment: Troubleshoot/Correct Gas Processing/Amine System	☐
25.01.08	Dehydration: Maintain/Repair Gas Fired Mole Sieve Dehydration System Controls	☐
25.01.09	Dehydration: Operate/Maintain Gas Fired Mole Sieve Dehydration System	☐
25.01.10	Dehydration: Start-up/Shutdown of Mole Sieve Dehydration System	☐
25.01.11	Dehydration: Troubleshoot/Repair Mole Sieve Dehydration System	☐
27.01.01	Gas Control	☐

Attachment 2

MS3002 History



Attachment 3

Naqvi, Zainab

From: Hadden, Thomas (Baker Hughes) <Thomas.Hadden@bhge.com>
Sent: Thursday, October 10, 2019 8:54 AM
To: Naqvi, Zainab
Cc: Von Maucher, Gary L (BHGE); Goss, Jonathan Y
Subject: RE: EXT: Kinder Morgan GE Frame 3

[This email message was received from the Internet and came from outside of Kinder Morgan]

Zainab, The 3 units at Pecos are Model A's. There is no modification available to this model to help with emissions due to age of the equipment (1950's era)

The LHE liner, water/steam injection, advanced tech upgrades would all require engineering studies before being able to provide any technical information for the Model A's.

SCR's have never been part of our scope of supply so I wouldn't be able to provide any technical information that would help with that.

I'll be at the KM offices this afternoon for a meeting at 1:00. Would you be available around 2:00 to talk?

Thanks,
Tom

From: Naqvi, Zainab
Sent: Wednesday, October 9, 2019 10:03 AM
To: Hadden, Thomas (BHGE)
Cc: Von Maucher, Gary L (BHGE) ; Goss, Jonathan Y
Subject: RE: EXT: Kinder Morgan GE Frame 3

Also,

I should clarify, I know Christine reached out to you regarding some Model A's, but the units that I'm referring to are Model #M3712R, Serial #s 95025, 95053, and 95055. I'm not sure if based on the "F3 History" classification, they still fall under the A model umbrella or another one, and how that might change some of the questions below.

Thanks,
-Zainab

From: Naqvi, Zainab
Sent: Wednesday, October 9, 2019 9:48 AM
To: 'Hadden, Thomas (BHGE)'
Cc: Von Maucher, Gary L (BHGE); Goss, Jonathan Y
Subject: RE: EXT: Kinder Morgan GE Frame 3

Tom,

Tomorrow is fine if we want to have a conversation, but I'll detail what I'm looking for below, since there's a chance it might take some time to put together.

In short, the state of New Mexico is requiring a BACT analysis on the NOX emissions from the three GE Frame 3 turbines that are located in Pecos River as a part of the Regional Haze improvement goals they are hoping to meet. I read through the emails between you and Jonathan and Christine, and was hoping to get the following questions answered:

1. Jonathan mentioned a water/steam injection as being a potential modification on turbines but stated that it was not available for this vintage of machine. Can you provide some more technical information on what that entails, and why it's not an option (due to size, age, configuration, etc)?

2. Would it be possible to get a more technical understanding of why the LHE liner installation, DLN retrofit, LT12 module are infeasible? For the LHE liner, have these been implemented elsewhere, or would we be the trial run for the modification (you mentioned an engineering study)? For the DLN upgrades, you stated that the F3 F model would be replaced with the F3 J model. If our units are A models, what would it take to even get from an A to an F, and then subsequently to a J? Are we essentially saying complete or near-complete replacement of the units? Same question for the LT12 – would we need an entirely new unit in order to install the LT12 module?

3. I'm not sure if it's been discussed, but would the installation of an SCR be possible on these units? From everything I've seen regarding these units, it looks like the SCR is the only potential option short of unit replacement, unless it's technically infeasible. If this is the case, can you explain why it is technically infeasible (are temperatures too low for catalyst, are the units too vintage or untested with catalyst, would an engineering study need to be done to determine if a catalyst would work, what's the time and cost associated with such a study)? If an SCR was possible, what would the timing/cost look like for an SCR installation? Have other older GE turbines been retrofit with SCR tech to reduce NOx? What would the operational limitations be?

I understand that this is an expedited request, but I'd like to have to have these answers as soon as available but by Thursday COB if possible. The report is due to the NMED by November 1.

Feel free to give me a call if you guys want to talk through the questions.
Thanks,
-Zainab

Zainab Naqvi
Air Permitting and Compliance
KINDER MORGAN
Natural Gas Pipelines
Office: 713-420-1841 x31841
Cell: 832-607-3115
Zainab_Naqvi@kindermorgan.com

From: Hadden, Thomas (BHGE) [mailto:Thomas.Hadden@bhge.com]
Sent: Tuesday, October 8, 2019 4:49 PM
To: Naqvi, Zainab
Cc: Von Maucher, Gary L (BHGE)
Subject: Re: EXT: Kinder Morgan GE Frame 3

[This email message was received from the Internet and came from outside of Kinder Morgan]

Zainab, I'll be back in the office Thursday will that be ok? I have copied Gary to this response he would be able to provide answers as well.

On Oct 8, 2019, at 4:04 PM, Naqvi, Zainab <zainab_naqvi@kindermorgan.com> wrote:

> Tom,
>
> I got your contact information from Jonathan Goss regarding the Frame 3 turbines that we have at our Pecos River Compressor Station in New Mexico. As a part of the regional haze BACT analysis that has been requested by the New Mexico Environmental Department, we're conducting an evaluation of the units for emissions improvements.
>
> If you have some time, can you please give me a call so we can talk through some of the data you had sent Jonathan earlier this year? The analysis due to the state is very time sensitive, so please feel free to call me ASAP at 713-420-1841 or my cell at 832-607-3115.
>
> Thanks,
> -Zainab
>
> **Zainab Naqvi**
> **Air Permitting and Compliance**
> **KINDER MORGAN**
> **Natural Gas Pipelines**
> **Office**: 713-420-1841 x31841
> **Cell:** 832-607-3115
> Zainab_Naqvi@kindermorgan.com

Attachment 4

From: Jones, Mark, NMENV
To: Naqvi, Zainab
Subject: Discussion on submittal and 2016-2018 today
Date: Wednesday, February 12, 2020 11:12:40 AM
Importance: High

[This email message was received from the Internet and came from outside of Kinder Morgan]

Hi Zainab,

Thanks for your call today. For most of the four-factor facilities we are using the 2016-2018 average emissions from future 2028 baseyear estimate for modeling. For your facilities we added a 5% utilization increase to the 2016-2018 averages for the 2028 baseyear. Since costs will be assessed on the future projection; If you are able to, please add the 5% utilization rates to the 2016-2018 averages when you assess costs in your submittal.

We just added a 5% increase across the board to all the emissions categories for the El Paso four-factor facilities.

It should not make a huge difference so if you have already done 2016-2018, that will work and we can adjust for the 5% increase In the next step of the process.

Let me know if you need clarification. I'll be around all day.
Thanks,
Mark

Mark Jones
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"Innovation, Science, Collaboration, Compliance"

Attachment 5

El Paso Natural Gas Company, LLC

Pecos River Compressor Station - Stack Test Data

Turbine Cost Analysis Interest Rate: 5.50%
All Units Period (yrs): 20

Cost Effectiveness Summary using Stack Test Data Emission Factors

Control Equipment	Unit	SCR Capital Cost ($)	Building Modification ($)	Total Annual Cost* ($)	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Selective Catalytic Reduction (SCR)	A-01	2,535,199	2,500,000	539,796	21.9	24,607
	A-02	2,535,199	2,500,000	549,439	57.9	9,491
	A-03	2,535,199	2,500,000	549,332	55.1	9,974

* Total Annual Cost includes the annualized capital cost as well as the direct and indirect annual operating costs.

El Paso Natural Gas Company, LLC

Pecos River Compressor Station - Stack Test Data

GE Model M3712R Turbine	Interest Rate:		5.50%	
A-01	Period (yrs):		20	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_x lb/hr:		17.00	lb/hr	<-- 2016 through 2018 average stack test results
NO_x tpy:		31.34	tpy	<-- Calculated using 2016 through 2018 average stack test results and 2016 through 2018 average actual operating hours.
SCR				
NO_x Reduction:		70%		<-- Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032
NO_x lb/hr:		5.10	lb/hr	
NO_x tpy:		9.40	tpy	
Turbine Housing Reconfiguration	$	2,500,000		<-- Estimated cost from EPNG
SCR Capital Investment	$	2,535,199		<-- EPA Cost Control Spreadsheet
Total Capital Investment	$	5,035,199		
Annualized TCI:	$	421,342		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	118,454		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	539,796		
Emissions Reduction:		21.9	tpy	
Cost Effectiveness:	**$**	**24,607.04**	**$/ton**	

Unit A-01: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new turbine or retrofit of an existing turbine? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?[1]	61.8	MMBtu/hour
What is the higher heating value (HHV) of the fuel?[1,2]	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	220,915,390	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 2900 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the Cost Estimate tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Fuel consumption adjusted for actual 2016 operating hours, per the 2016 Emission Inventory submittal (524.9 MMscf/yr * 4982.50/8760 hours/year = 298.55 MMscf/yr)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the turbine operates (tplant)	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR[2]	0.2751	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR[3]	0.0825	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})[4]	25975.21	ft³/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft³
29.4% aqueous NH_3	56 lbs/ft³

Select the reagent used: Ammonia

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Permitted NO_x emission rate / permitted heat input (53.1 lb/hr / 61.8 Mmbtu/hr)

[3] Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032; 70% efficiency

[4] Calculated based on the estimated actual annual fuel consumption and maximum heat input rate.

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh			* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit A-01: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	61.8	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	525,090,204	scf/Year
Actual Annual fuel consumption (Mactual) =		220,915,390	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.421	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3685	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	11.90	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	21.93	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.88	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	1,536,075	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	7,082.81	/hour
Residence Time	1/V_{space}	0.00	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.11	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia
Retrofit Factor (RF)	Retrofit to existing turbine	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1), where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	216.87	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	1,600	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	1,840	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	42.9	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	5	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	16	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	800	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	31.78	kW

Unit A-01: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Turbines

For Oil and Natural Gas-Fired Utility turbines between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility turbines >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial turbines between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial turbines >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,535,199	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$115,674	in 2018 dollars
Indirect Annual Costs (IDAC) =	$214,976	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$330,650	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,676	in 2018 dollars
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$2,300	in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$7,917	in 2018 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$5,181	in 2018 dollars
Direct Annual Cost =		$115,674	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,780	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$212,196	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$214,976	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$330,650	per year in 2018 dollars
NOx Removed =	21.9	tons/year

El Paso Natural Gas Company, LLC

Pecos River Compressor Station - Stack Test Data

GE Model M3712R Turbine	Interest Rate:		5.50%	
A-02	Period (yrs):		20	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_x lb/hr:		26.26	lb/hr	<-- 2016 through 2018 average stack test results
NO_x tpy:		82.70	tpy	<-- Calculated using 2016 through 2018 average stack test results and 2016 through 2018 average actual operating hours.
SCR				
NO_x Reduction:		70%		<-- Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032
NO_x lb/hr:		7.88	lb/hr	
NO_x tpy:		24.81	tpy	
Turbine Housing Reconfiguration	$	2,500,000		<-- Estimated cost from EPNG
SCR Capital Investment	$	2,535,199		<-- EPA Cost Control Spreadsheet
Total Capital Investment	$	5,035,199		
Annualized TCI:	$	421,342		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	128,097		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	549,439		
Emissions Reduction:		57.9	tpy	
Cost Effectiveness:	**$**	**9,491.17**	**$/ton**	

Unit A-02: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new turbine or retrofit of an existing turbine? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?[1]	61.8	MMBtu/hour
What is the higher heating value (HHV) of the fuel?[1,2]	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	377,406,695	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 2900 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the Cost Estimate tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Fuel consumption adjusted for actual 2016 operating hours, per the 2016 Emission Inventory submittal (524.9 MMscf/yr * 7165.5/8760 hours/year = 429.3 MMscf/yr)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the turbine operates (tplant)	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR[2]	0.4249	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR[3]	0.1275	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})[4]	44375.44	ft³/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft³
29.4% aqueous NH_3	56 lbs/ft³

Select the reagent used: Ammonia

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Permitted NO_x emission rate / permitted heat input (53.1 lb/hr / 61.8 Mmbtu/hr)

[3] Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032; 70% efficiency

[4] Calculated based on the estimated actual annual fuel consumption and maximum heat input rate.

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh			* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit A-02: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	62	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	525,090,204	scf/Year
Actual Annual fuel consumption (Mactual) =		377,406,695	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.719	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6296	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	18.38	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	57.87	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.88	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,624,195	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	11,511.83	/hour
Residence Time	1/V_{space}	0.00	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.11	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia
Retrofit Factor (RF)	Retrofit to existing turbine	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1), where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	227.96	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,734	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	3,144	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	56.1	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	7	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	25	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,200	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	31.78	kW

Unit A-02: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Turbines

For Oil and Natural Gas-Fired Utility turbines between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility turbines >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial turbines between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial turbines >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,535,199	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$125,317	in 2018 dollars
Indirect Annual Costs (IDAC) =	$214,976	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$340,293	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,676	in 2018 dollars
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$6,071	in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$13,525	in 2018 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$5,445	in 2018 dollars
Direct Annual Cost =		$125,317	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,780	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$212,196	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$214,976	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$340,293	per year in 2018 dollars
NOx Removed =	57.9	tons/year
Cost Effectiveness =	$5,880.46	per ton of NOx removed in 2018 dollars

El Paso Natural Gas Company, LLC

Pecos River Compressor Station - Stack Test Data

GE Model M3712R Turbine	Interest Rate:		5.50%	
A-03	Period (yrs):		20	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_x lb/hr:		24.55	lb/hr	<-- 2016 through 2018 average stack test results
NO_x tpy:		78.68	tpy	<-- Calculated using 2016 through 2018 average stack test results and 2016 through 2018 average actual operating hours.
SCR				
NO_x Reduction:		70%		<-- Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032
NO_x lb/hr:		7.37	lb/hr	
NO_x tpy:		23.60	tpy	
Turbine Housing Reconfiguration	$	2,500,000		<-- Estimated cost from EPNG
SCR Capital Investment	$	2,535,199		<-- EPA Cost Control Spreadsheet
Total Capital Investment	$	5,035,199		
Annualized TCI:	$	421,342		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	127,990		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	549,332		
Emissions Reduction:		55.1	tpy	
Cost Effectiveness:	**$**	**9,974.19**	**$/ton**	

Unit A-03: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new turbine or retrofit of an existing turbine? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?[1]	61.8	MMBtu/hour
What is the higher heating value (HHV) of the fuel?[1,2]	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	384,017,879	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	2900	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the Cost Estimate tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Fuel consumption adjusted for actual 2016 operating hours, per the 2016 Emission Inventory submittal (524.9 MMscf/yr * 6501.75/8760 hours/year = 389.6 MMscf/yr)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the turbine operates (tplant)	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR[2]	0.3973	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR[3]	0.1192	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})[4]	45152.79	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Permitted NO_x emission rate / permitted heat input (53.1 lb/hr / 61.8 Mmbtu/hr)

[3] Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032; 70% efficiency

[4] Calculated based on the estimated actual annual fuel consumption and maximum heat input rate.

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh			* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit A-03: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	62	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	525,090,204	scf/Year	
Actual Annual fuel consumption (Mactual) =		384,017,879	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.731	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6407	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	17.19	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	55.06	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.88		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,670,165	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	11,819.40	/hour	
Residence Time	1/V_{space}	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.11		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia	
Retrofit Factor (RF)	Retrofit to existing turbine	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1), where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	225.91	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,781	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	3,199	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	56.6	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	7	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	23	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,100	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	31.78	kW

Unit A-03: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Turbines

For Oil and Natural Gas-Fired Utility turbines between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility turbines >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial turbines between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial turbines >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,535,199	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$125,210	in 2018 dollars
Indirect Annual Costs (IDAC) =	$214,976	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$340,187	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,676	in 2018 dollars
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$5,776	in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$13,762	in 2018 dollars
Annual Catalyst Replacement Cost =		$5,397	in 2018 dollars
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$		
Direct Annual Cost =		$125,210	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,780	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$212,196	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$214,976	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$340,187	per year in 2018 dollars
NOx Removed =	55.1	tons/year

El Paso Natural Gas Company, LLC - Pecos River Compressor Station

Turbines

Units: A-01, A-02, A-03

Description: GE Regenerative Cycle Turbines (model M3712R)

ISO Rating:	**7150**	**hp**
Site Rating[1]:	**7150**	**hp**
Fuel Heating Value:	**1031**	**Btu/scf**
Heat Input Rate:	**56.45**	**MMBtu/hr**

	A-01	A-02	A-03
2016 through 2018 Average Operating Hours:	3,686.83	6,298.50	6,408.83
Fuel Cons. (MMscf):	275.20	415.66	397.27

Criteria Pollutant	Emission Factor A-01	Emission Factor A-02	Emission Factor A-03	Units	Source	A-01 TPY	A-02 TPY	A-03 TPY
NOx	17.00	26.26	24.55	lb/hr	2016 through 2018 average stack test results	31.338	82.699	78.679
CO	8.00	8.00	8.00	lb/hr	permit	14.747	25.194	25.635
VOC	0.0020	0.0020	0.0020	lb/MMBtu	AP-42	0.284	0.429	0.410
SO2	0.0030	0.0030	0.0030	lb/MMBtu	AP-42	0.426	0.643	0.614
PM	0.0070	0.0070	0.0070	lb/MMBtu	AP-42	0.993	1.500	1.434
HAP Pollutants								
Acetaldehyde	4.00E-05	4.00E-05	4.00E-05	lb/MMBtu	AP-42	0.006	0.009	0.008
Acrolein	6.40E-06	6.40E-06	6.40E-06	lb/MMBtu	AP-42	0.001	0.001	0.001
Benzene	1.20E-05	1.20E-05	1.20E-05	lb/MMBtu	AP-42	0.002	0.003	0.002
Ethylbenzene	3.20E-05	3.20E-05	3.20E-05	lb/MMBtu	AP-42	0.005	0.007	0.007
Formaldehyde	7.10E-04	7.10E-04	7.10E-04	lb/MMBtu	AP-42	0.101	0.152	0.145
Naphthalene	1.30E-06	1.30E-06	1.30E-06	lb/MMBtu	AP-42	0.000	0.000	0.000
PAH	2.20E-06	2.20E-06	2.20E-06	lb/MMBtu	AP-42	0.000	0.000	0.000
Propylene Oxide	2.90E-05	2.90E-05	2.90E-05	lb/MMBtu	AP-42	0.004	0.006	0.006
Toluene	1.30E-04	1.30E-04	1.30E-04	lb/MMBtu	AP-42	0.018	0.028	0.027
Xylene	6.40E-05	6.40E-05	6.40E-05	lb/MMBtu	AP-42	0.009	0.014	0.013
					Total HAPS	0.146	0.220	0.210

Op Hour Comparison

Operating Hours Per Year			
Yr/Unit	A-01	A-02	A-03
2014	6,920.92	5,983.92	7126.67
2015	5,602.33	4,018.83	5585.25
2016	4,982.50	7,165.50	6501.75
2017	754.75	7,916.25	7693.25
2018	5,323.25	3,813.75	5,031.50
2016	**4,982.50**	**7,165.50**	**6,501.75**
2014 – 2018 Avg. Hours	**4,716.75**	**5,779.65**	**6,387.68**
2016 – 2018 Avg. Hours	**3,686.83**	**6,298.50**	**6,408.83**

NMED Final Cost Evaluation
El Paso Natural Gas Company - Washington Ranch Storage Facility

Facility Information	
EPNG - Washington Ranch Storage Facility	**Facility**
Two 1980s vintage 2SLB RICE, 4,500 HP	**Units**
1 and 2	**Unit IDs**
LEC	**Evaluated Pollution Control**
0.5	**Target Emissions Rate (g NOx/bhp-hr)**

According to EPNG, units 1 and 2 already utilize LEC; they are equipped with a turbocharger, advanced ignition system, pre-combustion chambers (PCC) system, high pressure fuel injection, and an automatic balancing platform. Based on vendor information provided by EPNG, LEC can achieve a NOx emissions rate as low as 0.5 g/hp-hr - consistent with information provided by other facilities for Cooper-Bessemer RICE. Results from recent emissions testing indicate the current NOx emission rate from these units is already 0.5 and 0.8 g/hp-hr, respectively. Therefore, an evaluation of LEC is not appropriate or necessary.

NMED Final Cost Evaluation
El Paso Natural Gas Company - Washington Ranch Storage Facility

Facility Information

EPNG - Washington Ranch Storage Facility	**Facility**
Two 1980s vintage 2SLB RICE, 4,500 HP	**Units**
1 and 2	**Unit IDs**
Replacement with new RICE	**Evaluated Pollution Control**
0.3	**Target Emissions Rate (g NOx/bhp-hr)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired spark ignited lean-burn RICE >= 1875 bhp.

Supporting Information

2020	**Calendar year associated with cost estimates**
4500	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 1	Unit 2	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 14,521,500	$ 14,521,500	9/8/20 info from EPNG	All-in estimate ($/HP) x Maximum Capacity (HP)
Interest Rate (%)	R	8.53%	8.53%	EPNG 2/23/2020 CFO letter and 10/9/2020 email	
Useful Life (yr)	Y	30	30	ERG experience based on discussions with RICE manufacturers	
Capital Recovery Factor	CRF	0.0933	0.0933	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 1,354,943	$ 1,354,943	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	-	Incremental O&M reasonably negligible
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 1,354,943	$ 1,354,943	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	59%	29%	-	(Current actual emissions rate - Target emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	9.7	5.5	CY 2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by EPNG
Projected Actual Emissions (ton/yr)	PAE	9.7	5.5	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	5.8	1.6	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 235,491**	**$ 847,469**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 and thus assumed costs are in 2020$
Price Index	PI	1.34	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 315,558**	**$ 1,135,609**	-	CE1 x PI

NMED Final Cost Evaluation
El Paso Natural Gas Company - Washington Ranch Storage Facility

Facility Information

EPNG - Washington Ranch Storage Facility	**Facility**
Two 1980s vintage 2SLB RICE, 4,500 HP	**Units**
1 and 2	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Target Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
4500	**Maximum Power Output (hp/unit)**
2641	**Operating Schedule (hr/yr, average)**

Economic Evaluation

Cost Component		All Units (Combined)	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	On 2/14/20, EPNG provided a $1469/hp all-in Total Capital Cost (TCC) metric for EMD. On 9/9/20, EPNG provided an alternate cost estimate developed using "the KM-Cost Estimating Group's Developmental Cost Estimating Tool". The alternate estimate applied an unusual and insufficiently documented methodology that involved a base cost estimate for replacement RICE that was adjusted using EMD-specific costs and RICE-specific costs. Using detailed cost information provided by other facilities, NMED developed a TCC metric of $2,084/hp (2023$) for the installation of EMD. Costs associated with requisite substation and utility line upgrades were estimated separately and added to TCC to estimate Total Capital Investment (TCI).
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ 18,756,000	See Note	
Additional Capital ($)	AC	$ 10,770,000	EPNG estimate dated 9/9/20 and ERG experience	9 miles of medium voltage line @ $750k/mile; substation upgrade ($3M in 2020$ coverted to 2023$ using CEPCI)
Total Capital Investment ($)	TCI	$ 29,526,000	-	TCC + AC
Interest Rate (%)	R	8.53%	EPNG 2/23/2020 CFO letter and 10/9/2020 email	
Useful Life (yr)	Y	25	EPNG estimate dated 9/9/20	Consistent with other FFAs
Capital Recovery Factor	CRF	0.098	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 2,892,238	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 744,463	-	AED + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 1,119,463	Engineering estimate	Assumes units at 60% load, 95% efficiency and a $0.10/kWh price
Associated non-electricity O&M ($/yr)	AOM	$ -	Engineering judgment	Assumed to be negligible
Annual Fuel Credit ($/yr)	AFC	$ (375,000)	EPNG 2/23/21 email	Cost of fuel based on calendar year 2016 operation
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 3,636,702	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	15.2	CY 2023 emissions testing and average operating hours (2016-2021)	Sum of BAE of all units
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by EPNG
Projected Actual Emissions (ton/yr)	PAE	15.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	15.2	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 239,058**	-	TAC/ER
Price Index	PI	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 239,058**	-	CE1 x PI

REGIONAL HAZE FOUR-FACTOR ANALYSIS

El Paso Natural Gas Company, LLC
Washington Ranch Storage Facility

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1. EXECUTIVE SUMMARY

In the 1977 amendments to the Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across the United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

> *(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A).*
>
> This is known as a four-factor analysis.
>
> *(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B).*
>
> The uniform rate of progress or improvement is sometimes referred to as the glidepath and is part of the state's Long Term Strategy (LTS).

The second implementation planning period (2018-2028) for national regional haze efforts is currently underway. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural or biogenic and manmade or anthropogenic sources of emissions. Using a Photochemical Grid Model (PGM), the Western Region Air Partnership (WRAP), in coordination with the EPA, is tasked with comparing anthropogenic source contributions against natural background concentrations.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for major sources and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I area. From this analysis, 24 facilities were identified by the NMED. On July 18, 2019 the NMED informed El Paso Natural Gas Company LLC (EPNG) that its Washington Ranch Storage (Washington Ranch) facility

was identified as one of the sources contributing to regional haze at the Carlsbad Caverns National Park Class I area.

In coordination with WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. In the NMED's July 18, 2019 notification letter to EPNG, it specifies that any single piece of equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and/or 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The equipment at Washington Ranch as listed in TV Permit P064-R3, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant are reported in Table 1.

Table 1. Summary of Equipment and Applicability of the Four-Factor Analysis

Equipment	NO_X PTE (lb/hr)	NO_X PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 PTE (lb/hr)	SO_2 PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
Cooper-Bessemer / 12Q155HC2 2SLB RICE Unit A-01	27.3	119.5	Yes	0.48	2.1	No
Cooper-Bessemer / 12Q155HC2 2SLB RICE Unit B-02	27.3	119.5	Yes	0.48	2.1	No

Once the applicability of equipment and pollutants has been determined, potential retrofit control technologies must be identified. In accordance with 40 CFR 51 Appendix Y and at the recommendation of the NMED,[1] this is primarily achieved by utilizing the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) data. In order to determine the most relevant and current retrofit controls available, the RBLC is queried for the previous ten years. A summary of identified available retrofit controls along with a technical feasibility assessment for each control is provided in Section 2. The four-factor analysis is then conducted for those controls that are technically feasible.

[1] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

2. BACKGROUND INFORMATION & TECHNICAL FEASIBILITY

2.1. TWO-STROKE LEAN-BURN ENGINES

Washington Ranch has two (2) natural gas-fired two-stroke lean-burn (2SLB) reciprocating internal combustion engines (RICE), Units A-01 and B-02, that are subject to this four-factor analysis. The only pollutant subject to evaluation for these units is NO_X.

2.1.1. Two-Stroke Lean-Burn Engines Background

Natural gas-fired RICE are separated into multiple design classes, including 2SLB, 4-stroke lean-burn (4SLB), and 4-stroke rich-burn (4SRB). The four-stroke design uses four strokes of the piston, or two turns of the crankshaft, to complete the power cycle. The two-stroke design completes the power cycle in a single revolution of the crankshaft. Rich-burn engines are designed to operate close to the stoichiometric, or chemically balanced, air-to-fuel ratio (around 16:1) with exhaust oxygen levels less than 4 %, while lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1), with exhaust oxygen levels of 12 % or more.[2]

NO_X is formed in reciprocating engines via three mechanisms:

(1) Thermal NO_X - the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion,
(2) Fuel NO_X - the evolution and reaction of fuel-bound nitrogen compounds with oxygen, and
(3) Prompt NO_X - the early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The Washington Ranch engines use natural gas fuel, which contains a negligible amount of nitrogen compounds. Therefore, the formation of prompt and fuel NO_X will be insignificant. This analysis will focus on thermal NO_X. The rate of NO_X formation through the thermal NO_X mechanism is highly dependent upon the air-to-fuel ratio, combustion temperature, and residence time at the combustion temperature. Maximum thermal NO_X formation occurs near the stoichiometric air-to-fuel mixture ratio because combustion temperatures are greatest at this ratio.[3]

NO_X reduction in natural gas-fired RICE can be accomplished by three general methods, as follows:

(1) Post-combustion NO_X control technologies, which employ various strategies to chemically reduce NO_X.
(2) Combustion control techniques, for example reducing the peak flame temperature by introducing inerts that limit initial NO_X formation.
(3) Operational control methods, such as adjusting the timing or other operating parameters.

The PTE from each engine is reported in the facility's Title V permit P064-R3, as well as above in Table 1.

[2] "Emission Control Technology for Stationary Internal Combustion Engines," Manufacturers of Emission Controls Association, 2015
[3] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"

2.1.2. Potential NO_X Controls for 2SLB Engines

Retrofit control options identified for 2SLB RICE were identified via comprehensive review of the RBLC and available technical literature and are summarized in Table 2. A detailed description and discussion of the technical feasibility and anticipated performance of each control is provided below.

Table 2. Potential Control Options for 2SLB RICE

Control Equipment	Technically Feasible	NO_X Control Efficiency
Selective Catalytic Reduction	**No**	**N/A**
Clean Burn Technology	**Yes**	**27% - 82%**
Good Combustion Practices and Fuel Selection	**Yes**	**Base Case**

2.1.2.1. Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust stream of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[4] The chemical reactions for this process are shown in the equations below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

An SCR system includes the catalyst, reagent storage tank, reagent injector, reagent pump, pressure regulator, and electronic controls to accurately meter the quantity of reagent injected as a function of engine load, speed, temperature, and NOx emissions to be achieved. The lifespan of the catalyst is primarily determined by the erosion caused by the flue gas, deactivation caused by ammonium bisulfate (NH_4HSO_4) poisoning, as well as the build-up and fouling by the catalyst.

The characteristic exhaust temperature for 2SLB engines shows higher excess O_2 in the exhaust stack. For 2SLB engines, with typical exhaust O_2 from 14 to 16% (depending on make, model and operating condition), typical exhaust temperature is in the range of 450 to 600°F. Exhaust temperature is a critical design parameter for SCR performance, and accordingly, the catalyst material is selected based on the design temperature of the exhaust. Based on current technology and practices, SCR's optimal exhaust temperature is between 450 and 850°F range. Therefore, SCR's use as a control technology is limited to sources where the exhaust temperature is within that range.

A catalyst may perform at temperatures below 450°F, however complications such as reagent decomposition, reagent slip, catalyst contamination due to unreacted reagent (salt formation), etc. may arise. Catalysts may perform at lower temperatures (e.g., 450°F or lower), but other complications can arise at lower temperature (e.g., urea decomposition, competing reactions that form nitrates). Temperatures below the desired range reduce the reduction efficiency – i.e., increase NO_X and ammonia emissions.

[4] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

At higher temperatures, ammonia may "slip," meaning that a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. Unreacted reagent in the exhaust can form ammonium sulfates, which may plug or corrode downstream equipment, and/or catalyst damage may occur. Streams carrying large amounts of ammonium sulfates may blind the catalyst and may necessitate the application of a soot blower.

When compared to the typical 450 – 600°F temperature range for 2SLB engines, no single catalyst material offers high, stable performance across that range. Thus, even if other SCR technical issues (e.g., associated with reagent control) are addressed, current catalysts are not adequate to ensure stable, high-level performance for 2SLB engines.

In addition to the temperature issues, use of an aqueous reagent is common for engine applications. The water associated with aqueous urea (or ammonia) injection for an engine with higher NO_X emissions (e.g., NO_X is not controlled) could decrease exhaust temperature by 5 to 20 °F. This further complicates system engineering and catalyst material requirements.

For engines that typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia injection to gain the reductions needed.[5] In the case of Washington Ranch, the two engines run at ongoing variable loads.

Finally, there has been no application of SCR on this model of Cooper engines (see attached RBLC results). A thorough twenty-year review of the RBLC tables was conducted and there were no examples of an SCR being used as a control for 2SLB engines. The lack of availability or comparable use of an SCR on these Cooper engines presents the case that this control technology is considered technically infeasible. Consequently, SCR is not evaluated further in this four-factor analysis.

2.1.2.2. Clean Burn Technology

Clean Burn Technology (CBT) is another term for utilizing combustion mixtures in engines with fuel-lean air-to-fuel ratios. This method of reducing NO_X emissions involves reconfiguring the engines by adding or enhancing an air-to-fuel ratio controller, making the unit capable of operating at optimal air-to-fuel ratios.

As described in Section 2.1.1 of this report, rich-burn engines are normally designed to operate close to the stoichiometric, or chemically balanced, air-to-fuel ratio of 16:1, while lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1). A combustion mixture with a higher air-to-fuel ratio results in reduced NO_X emissions, because using fuel-lean mixtures lowers the combustion temperature by diluting energy input. 2SLB engines are typically designed to operate at the high air-to-fuel ratios employed in CBT; however, further increasing the air-to-fuel ratio in lean-burn engines can decrease the NO_X emissions.[6]

In order to avoid derating the engine (which can result in lower engine efficiency), combustion air must be increased at constant fuel flow. To achieve this, the engine will need to be retrofitted with a turbocharger, which forces additional air into the combustion chamber, as well as an automatic air-to-fuel ratio controller.

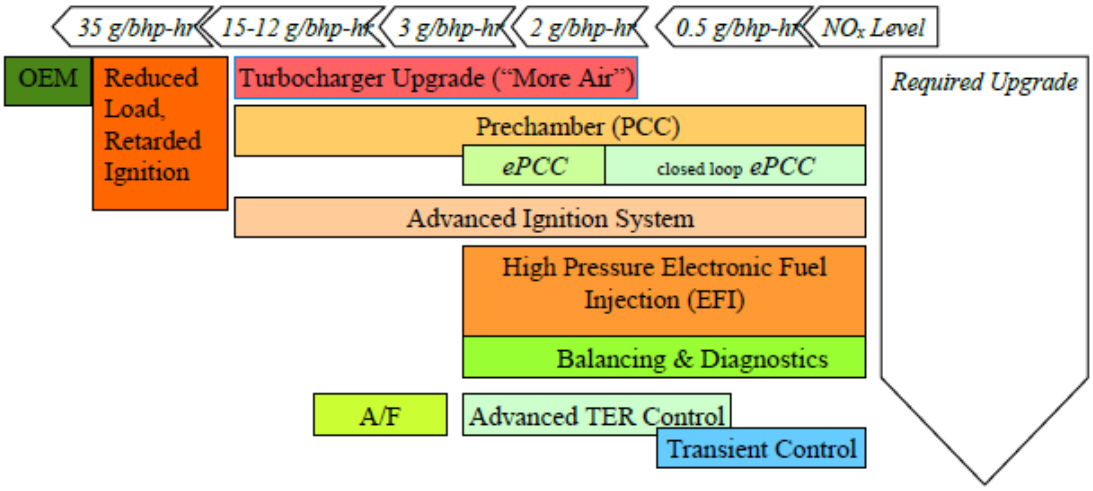
[5] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
[6] State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines, State of New Jersey Department of Environmental Protection, 2003.

Many 2SLB engines, such as naturally aspirated engines, do not have identical air-to-fuel ratios in each cylinder, which can result in limited ability to vary the air-to-fuel ratio. To maintain acceptable engine performance at lean conditions, high-energy ignition systems (HEIS) have been developed that promote flame stability at very lean conditions.[7]

2SLB engines are mechanically capable of being retrofitted with more sensitive air-to-fuel ratio controllers and running on higher air-to-fuel ratio combustion to control NO_X emissions. Therefore, it has been determined that this method of NO_X control is feasible for the 2SLB engines at Washington Ranch. Air-to-fuel ratio adjustment generally achieves a 5 to 30% reduction in NO_X emissions; however, this reduction is very specific to each engine and typical loading[8].

EPNG employs Hoerbiger as a vendor for units A-01 and B-02. Hoerbiger utilizes the "Layered Approach Strategy" (Figure 1) to efficiently run the units at Washington Ranch. The two units at Washington Ranch are currently equipped with a turbocharger, advanced ignition system, Pre-Combustion Chambers (PCC) System, High Pressure Fuel Injection, and an Automatic Balancing Platform. Based on manufacturer guidance, the addition of these clean burn technologies allows the engines to range from 2.75 to 0.5 g/hp-hr, which allows for a 27% to 82% reduction in NO_X emissions; thus, no further assessment of these control practices is included in this report.

Figure 3. Hoerbiger's Layered Approach Strategy for Clean Burn Technologies



2.1.2.3. Good Combustion Practices and Fuel Selection

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

[7] Ibid
[8] Ibid

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from large natural gas-fired lean-burn stationary internal combustion engines; therefore, it has been determined that this method of NO_X control is feasible for the 2SLB engines at Washington Ranch. EPNG has developed Reciprocating Mechanical Inspection and Maintenance Best Practices procedures, which are based on manufacturer recommendation, and EPNG has systems in place to ensure that the engines are operated in accordance with this at Washington Ranch. No further assessment of these control practices is included in this report.

3. SUMMARY & CONCLUSIONS

Based on a comprehensive review of the RBLC, available literature, and vendor input of available control technologies for the natural gas fired engines located at Washington Ranch, EPNG has determined that clean burn technology and good combustion practices are the only technically feasible control options for the two units. As EPNG already deploys these control technologies, there are no further factors to evaluate.

4. SUPPORTING DOCUMENTATION

Appendix A – RBLC Tables

Appendix B – EPNG Best Practices Procedures

APPENDIX A – RBLC TABLES

RBLC Analysis for Natural Gas-Fired Lean-Burn Stationary Internal Combustion Engines – NO_x

	Control Technology	Selective Catalytic Reduction (SCR) [a,b]	Non-Selective Catalytic Reduction (NSCR) [b]	Clean Burn Technology	Good Combustion Practices and Fuel Selection [c]
IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	A nitrogen-based reagent (e.g., ammonia, urea) is injected into the exhaust stream downstream of the combustion unit. The reagent reacts selectively with NO_x to produce molecular N_2 and water in a reactor vessel containing a metallic or ceramic catalyst.	This technique uses residual hydrocarbons and CO in rich-burn engine exhaust as a reducing agent for NO_x. In an NSCR, hydrocarbons and CO are oxidized by O_2 and NO_x. The excess hydrocarbons, CO, and NO_x pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H_2O and CO_2, while reducing NO_x to N_2.[b]	Natural gas fueled engines that operate with a fuel-lean air/fuel ratio are capable of low NO_x emissions.	NO_x emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following EPA's "Good Combustion Practices" guidance document, good combustion practices can be maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices the unit will operate as intended with the optimal NO_x emissions.
	Other Considerations	Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as "ammonia slip." Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.	N/A	N/A	N/A
ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Not included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Not included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.
	Feasibility Discussion	Technically infeasible. For engines which typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia to gain the reductions needed.	Technically infeasible. The NSCR technique is limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes 4-stroke rich-burn naturally aspirated engines and some 4-stroke rich-burn turbocharged engines. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures.	Technically feasible.	Technically feasible.
RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency			27% - 82%	Base Case

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
b. U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
c. EPA Guidance document "Good Combustion Practices" available at: http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf.

Raw RBLC Review

RBLC ID	Facility Name	EPA Region	Permit Number	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Polluntant	Standard Emission Limit	Standard Emission Limit Unit	Cost Effectiveness	Incremental Cost Effectiveness	Cost Verified	Pollutant Compliance Notes
NE-0015	KN ENERGY. INC	7	56628R01	2-CYCLE LEAN BURN ENGINE, UNIT 2505E	NATURAL GAS	1000	HP	ALL CONTROLLED BY 2ND GENERATION CLEAN BURN CONTROLS.	Nitrogen Oxides (NOx)	2	G/BHP-H	0	0	N	standard units estimated using process information.
NE-0015	KN ENERGY. INC	7	56628R01	IC ENGINE, 2503E, COOPER GMVA-10	NATURAL GAS	1265	HP		Nitrogen Oxides (NOx)	12	G/BHP-H	0	0	N	standardized units estimated from process information
NE-0015	KN ENERGY. INC	7	56628R01	IC ENGINE, 2504E, COOPER GMVA-6	NATURAL GAS	750	HP		Nitrogen Oxides (NOx)	12	G/BHP-H	0	0	N	standardized units estimated from process information
NE-0015	KN ENERGY. INC	7	56628R01	IC ENGINE, 2511E, COOPER GMVA-6	NATURAL GAS	750	HP		Nitrogen Oxides (NOx)	15	G/BHP-H	0	0	N	standardized units estimated from process information

APPENDIX B – EPNG BEST PRACTICES PROCEDURES

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1. Scope

1.1. General

Historically, some "Best Practices" documents were developed to cover specific regions, pipelines, or other limited-scope situations. While such documents may not agree with all provisions of Company Operating and Maintenance (O&M) Procedures, they contain vital information and considerations that may prove useful to many users.

Best Practices documents are intended to *complement* Company O&M Procedures. As such, this procedure provides *recommendations* and *guidance* to supplement the Company and Code Requirements defined within O&M Procedures, Engineering Standards, and other Company Compliance Documents.

In all applications, Company O&M Procedures and Engineering Standards shall prevail as Company Requirements.

1.2. Reciprocating Mechanical Inspection/Maintenance - Low Speed

A Mechanical Inspection aids in evaluating an engine's condition, promoting high reliability and reduced maintenance costs.

2. Recommendations

A) A periodic Mechanical Inspection should be completed on each reciprocating engine and compressor. The Mechanical Inspection consists of a visual crankcase inspection, web deflection, bearing clearance checks, and distance piece/doghouse inspections.

B) The inspection interval for each inspection item is listed in Table A (below).

C) The inspection interval is to be developed by Operations, in consultation with the Field Engineer and the Mechanical Project Support Teams.

D) The inspection interval will consider engine type, utilization, condition, etc for each particular engine.

E) Also listed in Table A (below) is the maximum inspection interval in hours or months, whichever occurs first. Note that inspections may be performed more frequently than the values shown in Table A.

For additional technical reference on Bearing Inspection Procedures, Failure Modes, and checking Bearing Clearances, refer to **Attachment 1 - Technical References**, at the end of this document.

Inspection Items	Inspection Interval	Maximum Hours	Maximum Months
Crankcase Inspection	TBD	16,000	48
Crankshaft Deflection	TBD	16000	48
Bearing Clearances	TBD	16000	48
Bearing Inspection	TBD	As required	As required
Distance Piece/Doghouse	TBD	16000	48

Table A – Inspection Intervals

3. Procedure

All elements of the Mechanical Inspection should be performed. For additional technical reference on Bearing Inspection Procedures, Failure Modes, and checking Bearing Clearances, refer to Attachment 1 - Technical References, at the end of this document.

A) Crankcase Visual Inspection

1) Anytime a crankcase door is removed from an engine, that part of the crankcase should be inspected. In addition, the crankcase of each engine should be drained periodically and carefully inspected.

2) Thoroughly inspect the inside of the crankcase for any foreign matter such as babbitt, bronze dust, or iron filings which are the indicators of bearing or gear failures, piston and cylinder wear, etc.

3) When each door is removed, its crankcase side should be inspected for foreign material thrown there by the centrifugal force of the connecting rod.

4) The walls and bottom of the crankcase should always be carefully checked for metal particles.

5) Each main bearing cap and connecting rod cap should be checked for discoloration caused by over-heated bearings. The entire crankcase should be observed for any blue discoloration, and if any is found, a thorough investigation and dimensional check should be made.

6) All lubricating oil lines and fittings, such as those from the lube oil header to each main bearing, should be checked for integrity.

7) On units with pre-lube pumps, run the pump and visually check the oil from each side of the main bearings to determine if there is an abnormal oil flow.

8) Bolts, nuts, and studs require a complete inspection for tightness. Where it is not possible to use a wrench on a nut or bolt to check for tightness because cotter pins and wires are used for locking devices, a small hammer can be used to tap each bolt.

9) Review recent oil analysis reports and check the general condition of the oil by looking for lacquer formations on machined surfaces or deposits of sludge.

10) Each piston should be moved to top dead center and as much of the liner as possible checked for scuff or score marks. The piston should then be moved to bottom center and the piston skirt inspected for score marks and loss of piston plating.

B) Bearing Clearances

1) Bearing clearances are to be checked during the Mechanical Inspection of the engine, recorded on the Mechanical Inspection form and will become part of the permanent records of the engine.

C) Crankshaft Deflections

2) At the recommended inspection interval, web deflection readings are to be taken on each throw of the crankshaft.

3) Deflection readings are to be recorded on the Mechanical Inspection form and will become part of the permanent records of the engine.

D) Visual Inspection of Bearings

1) Bearings will be pulled and visually inspected when indications of bearing wear are noted (excessive bearing clearances).

E) Distance Piece/Doghouse Inspections

1) Collect the required measurements per the Mechanical Inspection Form

F) Mainframe Movement Checks

1) Prior to shutting down the unit for Mechanical Inspection, ensure that a Engineer Technician has performed a mainframe movement check. (Refer to **Best Practices COMP103-1 - Engine Maintenance Analysis**)

4. Documentation

Some Pipelines and related Field Staff use one or more of the following:

- MAXIMO as an activities scheduling utility
- COMET for Compressor Data tracking

Until such time as these systems (MAXIMO, COMET, etc.) are superseded, the following information is provided for user reference:

MAXIMO PM

- Mechanical Inspection - Varies but NTE 48 months or 16,000 hours operated.

Mechanical Inspection Forms Workbook (COMP-2007)

- Retention - Life of Equipment
- Retention Location - Site

5. References

- **Best Practices COMP103-1 - Engine Maintenance Analysis**
- **COMP-2007 Mechanical Inspection Forms Workbook.xlsx**
- **Environmental, Health, and Safety Policy Manual**
- **O&M Procedures Manual**

Attachment 1 - Technical References

Bearing Inspection Procedure and Explanation

One cause of bearing failure is improper clearance between the bearings and the journal. Bearings are designed to run on a film of oil and will not normally come in contact with the journal when in operation. The flow of oil through the bearing dissipates the heat generated in the bearing, and too little or too much clearance between the bearing and journal upsets this balance of oil flow, heat dissipation, and temperature rise.

In the case of too little clearance, the oil film can 'thin out', allowing contact between the journal and bearing. Too much clearance allows the oil to escape from the bearing, allowing excessive impact to be transmitted into the bearing. This causes excessive wear or allows other bearings to become over-heated, because they are starved of oil.

Bearing failure can result in:

- Scored crankshaft
- Bent or destroyed shaft from excessive heat
- Heat checks in shaft
- Out-of-round journal
- Warped or distorted bearing support and bearing cap
- Destroyed connecting rod

Three acceptable methods for checking bearing clearances:

The feeler-gauge method consists of inserting a feeler gauge into the space between the shaft and the bearings. Vary the thickness until a thickness equal to the clearance is achieved. When the engine is shut down, the crankshaft should be resting on the bearing supports. It is important to determine this. A .0015-inch feeler gauge can be used to make this determination.

The Plastigage method requires that the bearing cap and one-half shell be removed. The Plastigage is then placed on the shaft. The bearing shell and cap are replaced and tightened. The Plastigage is squeezed into conformation with the clearance. When it is removed, its thickness may be measured, indicating the clearance. Soft fuse wire may be used instead of the Plastigage. Make sure that it is softer than the bearing material.

The Jack method consists of attaching a dial indicator to the frame of the engine with the button placed against the shaft. Place a jack under the shaft and jack up on the shaft; the clearance is measured on the dial indicator. Use skids or a metal plate to ensure that the load from the jack is distributed across the oil pan if necessary. On main bearings, it is necessary to make sure that the shaft is resting on the lower bearing shell. The jack should be placed on top of the shaft first, and pressure exerted on the shaft to determine if there is any downward movement that would be an indication the bearing is being bridged by the shaft. If a bridged bearing is detected, notify a Field Engineer immediately.

Any or all of these methods may be used. Each requires skill and practice to get repeatable readings. The manufacturer's instruction book should be checked for recommendations.

Any program of bearing inspection and maintenance should be designed to minimize the catastrophic results of bearing failure. Evidence that indicates possible failure may be any of the following:

- Excessive clearance
- Clearance closed up
- Loss of crush
- Bearing material particles in the crankcase or oil filter
- Bearing protective device shuts the engine down
- Discoloration of the bearing or bearing cap

Some general rules for bearing inspection:

Connecting Rod Bearings

On most engines, the connecting rod bearings must be removed to pull pistons. They should receive a close visual inspection at this time

They should be removed and inspected when visual evidence indicates possible failure.

If experience indicates that specific bearings require inspection after a certain length of time, they should be pulled and inspected.

Main Bearings

Main bearings should be removed and inspected when any evidence indicates possible failure.



El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

February 14, 2020

Mr. Mark Jones
Mr. Kerwin Singleton
NMED Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

RE: El Paso Natural Gas LLC – Washington Ranch Storage Facility
Regional Haze Four-factor Analysis December 23, 2019 Request for Additional Information

Dear Mr. Jones and Mr. Singleton:

This letter addresses the additional information request for the El Paso Natural Gas Company, L.L.C. (EPNG) – Washington Ranch Storage Facility Four-Factor Analysis report received on December 23, 2019. For the Washington Ranch Storage Facility there were a total of seven item requests pertaining to the NO_X emissions for both engines. Please see the responses for each item request below.

1. *Consider Good Combustion Practices (GCP) and routine maintenance as controls and provide the details of a maintenance schedule, employee training and operating procedures used to achieve emissions reductions.*

   Washington Ranch complies with the routine maintenance schedule pursuant to A201.A in NSR Permit No. 0428M7. Washington Ranch complies with periodic testing pursuant to A201.B in order to monitor NO_X, CO, and VOC emissions. Standard operating procedures and maintenance practices have been developed based on manufacturer's recommendations to keep the equipment in operating condition.

   Additionally, each employee has an Operator Qualification (OQ) Checklist that is completed and tracked in the OQ system. Operators are paired with other operators and work as trainees until they are deemed qualified on the piece of equipment and operation at the site. During the training period, they are exposed to station operations, responding to call outs with operators, station shutdowns, and purging and pressurizing stations. This training period lasts on average about one (1) year. Attached is a sample OQ qualification checklist used to track employee training (Attachment 1).

2. *Consider and include a discussion on the feasibility and cost of technology that limits engine capacity to reduce NOX emissions. Also evaluate limitations on engine operating hours or shutting down engines that are no longer needed to reduce total NOX emissions.*

   As the two units at Washington Ranch are two-stroke lean burn engines (2SLB), the technology for reducing NO_X emissions are limited.

   EPNG, being a transmission pipeline is also regulated by the Federal Energy Regulatory Commission (FERC). Hours of operation and facility horsepower are certificated by FERC to ensure effective operation of the facility to meet customer demands. EPNG must maintain the permitted loads and operating hours for the units in order to effectively operate and satisfy supply contracts in place. Accordingly, any operational restrictions could have the potential to

significantly disrupt gas supply in the area. Consideration of limiting capacity or operating hours will result in violation of EPNG's FERC commitment and will result in potential contract breach (with associated financial penalty), re-negotiating long-term contracts, and re-applying for a FERC certification.

3. *Consider and include a discussion of variations of Clean Burn Technology (CBT) used to reduce NOX emissions that may be more effective than the existing package if available. Please include cost and efficiencies in analysis. Show documentation of vendor quotes with cost and control efficiency.*

   As noted in the report submitted November 1, 2019, the engines are currently equipped with the most recent available control technologies. Research indicates that there are no additional control technology available for this type 2 SLB engines at Washington Ranch. The Clean Burn Technologies currently installed on the two units include a turbocharger, advanced ignition system, Pre-Combustion Chambers System, High Pressure Fuel Injection, and an Automatic Balancing Platform. The engines are currently permitted at 2.75 gr/bhp-hr. EPNG has determined that no other package is currently available for this type of equipment at this time.

4. *Please verify and provide documentation that control systems have not yet been developed for selective catalytic reduction (SCR) controls that can handle variable load engines. This appears to be one main reason that SCR has not been implemented on two-stroke lean burn (2SLB) internal combustion engines in oil and gas midstream operations.*

   U.S. EPA, Ap-42, Section 3.2 "Natural Gas-Fired Reciprocating Engines" currently states:

   > "For engines which typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia to gain the reductions needed."

   As noted in the November Four Factor Analysis, a 20-year review of the RBLC found that no 2SLB engines had used SCR as a control technology. Therefore, EPNG cannot comment on whether an SCR has been developed for 2SLB engines.

5. *Please consider and include a discussion on the feasibility of replacing natural gas-fueled engines/turbines with commercial electric powered compressors.*

   EPNG conducted a review of the feasibility of replacing natural gas-fueled engines with commercial electric powered compressors. Although a complete four-factor analysis has not been conducted, an estimated cost summary was developed for the potential scope and has been included as Attachment 2.

   Although this project is technically feasible, it is cost prohibitive. Additionally, given the life of the existing units and the fact that there is no current plans to replace them, a unit replacement is considered outside the scope of the Regional Haze Rule four factor analysis. Per Appendix Y to Part 51—Guidelines for BART Determinations Under the Regional Haze Rule Section IV.D.1.5:

   > "We do not consider BART as a requirement to redesign the source when considering available control alternatives. For example, where the source subject to BART is a coal-

fired electric generator, we do not require the BART analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting on a per unit basis."

This report is essentially a BART analysis with only 4 factors which are reviewed. EPNG will only submit alternative control options and will not assess replacing equipment.

6. *Provide vendor specifications that include the cost information, recommendations, and equipment specifications for the engine control estimates. This information is required to complete review of the analyses.*

   At this time, there are no proposed control technologies to improve emissions on the engines at Washington Ranch. Therefore no vendor data is available for submittal at this time.

7. *Provide any electronic spreadsheets used for control technology calculations.*

   At this time, there are no proposed control technologies to improve emissions on the engines at Washington Ranch. Therefore no spreadsheets are available for submittal at this time.

If you have any other questions, please do not hesitate to reach me at 713-420-1841 or via email at Zainab_Naqvi@kindermorgan.com.

Sincerely,

Zainab Naqvi
Air Permitting and Compliance
Kinder Morgan

Attachment 1

OPERATOR QUALIFICATION
Appendix G
COVERED TASK ASSIGNMENTS - GAS
Revised 3/23/2017

Employee Name:	EE Number:	Date:
Supervisor's Name:	Region/Location:	
Date Discussed with Employee:	***Supervisor's Signature***	

Submit this form with assigned covered tasks checked in the *Yes* column to your Regional OQ Coordinator.

CT #	Covered Task Title	Yes
01.01.01	Abnormal Operating Conditions	☐
02.01.01	Gas Detection & Alarm System Maintenance & Performance Test	☐
02.02.01	Isolation of Compressor Units	☐
02.03.01	Compressor Station Inspection & Testing of Remote Control Shutdown Devices	☐
03.01.01	Operating Compressor Units: Remote	☐
03.01.02	Operating Compressor Units: Manual	☐
03.02.01	Shutting Down Compressor Units: Remote	☐
03.02.02	Shutting Down Compressor Units: Manual	☐
03.03.01	Starting Compressor Units: Remote	☐
03.03.02	Starting Compressor Units: Manual	☐
04.01.01	Measure Damage on Installed Pipe and Components	☐
04.01.02	Corrosion Monitoring – Atmospheric, External, and Internal: Offshore Pipelines	☐
04.01.03	Visual Inspection of Buried Pipe and Components When Exposed	☐
04.01.04	Visual Inspection of Internal Surface of Pipe	☐
04.01.05	Visual Inspection for External/Atmospheric Corrosion (effective 6/30/17)	☐
04.01.06	Insert and Remove Coupons/Probes for Internal Corrosion Monitoring	☐
04.01.07	Nondestructive Testing – Magnetic Particle Testing of Pipe	☐
04.02.01	Coating Maintenance /Application and Repair – Sprayed, Brushed, or Rolled	☐
04.02.02	Coating Maintenance/Repair – Wrapped	☐

CT #	Covered Task Title	Yes
05.01.01	Cathodic Protection System Maintenance: Rectifiers	☐
05.01.02	Cathodic Protection System Maintenance: Electrical Isolation	☐
05.01.03	Cathodic Protection System Maintenance: Anodes, Anode Ground Beds, & AC Voltage Mitigation (task name change)	☐
05.01.04	Inspect or Test Cathodic Protection Bonds (task name change)	☐
05.01.05	Cathodic Protection System Maintenance: Reverse Current Switches	☐
05.01.06	Cathodic Protection System Maintenance: Automatic Potential Controlled Protection Systems	☐
05.01.07	Cathodic Protection System Maintenance: AC Voltage Mitigation System	☐
05.01.08	Cathodic Protection: Read Rectifier (effective 5/1/17)	☐
05.02.01	Cathodic Protection Systems – Electrical Connections	☐
05.03.01	Cathodic Protection System Testing: Test Stations	☐
05.03.02	Cathodic Protection System Testing: Pipe to Soil	☐
06.01.01	Indirect Inspection: Close Interval Survey	☐
06.01.02	Indirect Inspection: Direct Current Voltage Gradient (DCVG) Survey	☐
06.01.03	Indirect Inspection: Voltage Gradient (ACVG) Survey	☐
06.01.04	Indirect Inspection: AC Current Attenuation (ACCA or PCM) Survey	☐
07.01.01	Locating, Installing & Protecting Customer Meters & Regulators: Residential & Small Commercial	☐
07.01.02	Locating, Installing & Protecting Customer Meters & Regulators: Large Commercial	☐
07.02.01	Customer Pressure Regulating, Limiting & Relief Device: Residential & Small Commercial	☐
07.02.02	Customer Pressure Regulating, Limiting & Relief Device: Large Commercial & Industrial	☐
08.01.01	Locating Pipelines	☐
08.02.01	Damage Prevention During Excavation Activities	☐
09.01.01	System Patrolling	☐
10.01.01	Plastic Pipe – Electrofusion: Couplings	☐
10.01.02	Plastic Pipe – Electrofusion: Sidewall	☐
10.02.01	Plastic Pipe – Butt Heat Fusion	☐
10.03.01	Plastic Pipe – Sidewall Heat Fusion	☐
10.04.01	Mechanical Joints: Stab Fittings	☐

CT #	Covered Task Title	Yes
10.04.02	Mechanical Joints: Compression Couplings 2” & Less	☐
10.04.03	Mechanical Joints: Compression Couplings Greater Than 2”	☐
10.05.01	Joining of Pipe - Flange Assembly	☐
10.05.02	Joining of Pipe/Tubing – Threaded Fittings	☐
10.07.01	Solvent Cement Joints	☐
11.01.01	Direct/Inspect In-service Pipeline Lowering	☐
11.02.01	Detect/Inhibit/Mitigate Pipeline Hydrate Formation in Pipeline	☐
12.01.01	Leakage Survey: Walking	☐
12.01.02	Leakage Survey: Mobile	☐
12.02.01	Outside Leakage Investigation, Pinpointing and Grading	☐
12.03.01	Inside Gas Leakage Investigation	☐
13.01.01	Leak & Strength Test – Service Lines, Mains & Transmission Lines: Gaseous: Test Pressures < = 100 psi	☐
13.01.02	Leak & Strength Test – Service Lines, Mains & Transmission Lines: Gaseous: Test Pressures $\geq$ 100 psi	☐
13.01.03	Leak & Strength Test – Service Lines, Mains & Transmission Lines: Hydrostatic Test	☐
13.01.04	Leak & Strength Test – Service Lines, Mains & Transmission Lines: Test at Operation Pressure	☐
14.01.01	Abandonment or Inactivation of Facilities	☐
14.02.01	Backfilling	☐
14.03.01	Installation of Steel Pipe – Field Bends	☐
14.04.01	Casing Vents and Seals	☐
14.05.01	Underground Clearances	☐
14.06.01	Installation of Plastic Pipe: Direct Burial	☐
14.06.02	Installation of Plastic Pipe: Boring	☐
14.06.03	Installation of Plastic Pipe: Plowing/Planting	☐
14.06.04	Installation of Plastic Pipe: Plowing/Pull-In	☐
14.06.05	Installation of Plastic Pipe: Above Ground	☐
14.06.06	Installation of Plastic Pipe: Insertion	☐
14.07.01	Installation of Steel Pipe: Direct Burial	☐
14.07.02	Installation of Steel Pipe: Boring	☐
14.07.03	Installation of Steel Pipe: Plowing/Pull-In	☐
14.07.04	Installation of Steel Pipe: Above Ground	☐

CT #	Covered Task Title	Yes
14.07.05	Installation of Steel Pipe: Insertion	☐
14.08.01	Cover – Service Lines, Mains & Transmission Lines	☐
14.08.02	Cover – Offshore Pipelines	☐
14.09.01	Inspection: Compliance with Procedures & Standards	☐
14.09.02	Inspection: Inspection of Materials	☐
14.10.01	Line Markers	☐
14.11.02	Pipeline Shutdown, Startup or Pressure Change: Stopple Fitting	☐
14.11.03	Pipeline Shutdown, Startup or Pressure Change: Operating Identified Valve(s)	☐
14.11.04	Pipeline Shutdown, Startup or Pressure Change: Method(s) Required for Other Pipe Materials	☐
14.11.05	Launching and Receiving Internal Devices	☐
14.12.01	Protection from Hazards	☐
14.13.01	Protection When Minimum Cover Not Met	☐
14.14.01	Purging: Large Volume, i.e. Segment of Main or Transmission Line, etc.	☐
14.14.02	Purging: Small Volume, i.e. Service Line, Short Pipeline Segments, Compressor, Component, etc.	☐
14.15.01	Uprating: Reinforce or Anchor Offsets, Bends and Dead Ends – Longitudinal Straps	☐
14.15.02	Uprating: Reinforce or Anchor Offsets, Bends and Dead Ends – Anchoring & Buttressing	☐
14.16.01	Installation of Steel Pipe – Repair of Imperfections or Damage: Grinding	☐
14.18.01	Support, Expansion Joint and Anchor Maintenance – Exposed Pipeline	☐
14.19.01	Tapping Steel and Plastic Pipe: Manual (Self-Tapping)	☐
14.19.02	Tapping Steel and Plastic Pipe: Mechanical Tapping Equipment	☐
14.20.01	DOT Inspection of Valves	☐
14.20.02	Repair Valves	☐
14.21.01	Segment Removal	☐
14.22.01	Leak Clamps & Sleeves: Bolt-On Type	☐
14.22.02	Leak Clamps & Sleeves: Composite Sleeve (Clock Spring)	☐
15.01.01	Odorization – Mains & Transmission Lines: Periodic Sampling	☐
15.01.02	Odorization – Mains & Transmission Lines: Odorizer Maintenance	☐
16.01.01	Gas Quality: Operate/Test/Maintain Carbon Dioxide (CO2) Analyzers	☐
16.01.02	Gas Quality: Maintain/Service Chromatographs	☐
16.01.03	Gas Quality: Operate/Test/Maintain Oxygen (O2) Analyzers	☐
16.01.04	Gas Quality: Operate/Test/Maintain Sulfur Analyzers	☐

CT #	Covered Task Title	Yes
16.01.05	Gas Quality: Operate/Test/Maintain Moisture Analyzers	☐
16.01.07	Gas Quality: Operate & Maintain Gas Samplers	☐
16.01.08	Gas Quality: Troubleshoot/Repair Chromatographs	☐
16.01.09	Gas Quality: Troubleshoot & Repair Sulfur Analyzers	☐
16.01.10	Gas Quality: Troubleshoot/Repair Moisture Analyzers	☐
16.01.11	Gas Quality: Troubleshoot/Repair Carbon Dioxide (CO2) Analyzers	☐
16.01.12	Gas Quality: Troubleshoot/Repair Oxygen (O2) Analyzers	☐
18.01.01	Overpressure Safety Devices – Inspect, Test, and Calibrate Relief Valves	☐
18.01.02	Pressure Limiting Devices – Inspect, Test and Calibrate	☐
18.02.01	Vault Maintenance	☐
20.01.01	Service Line Replacement	☐
20.01.02	Service Line Replacement: Underground Service Entrance (Prerequisite 20.01.01)	☐
20.03.01	Service Lines Not in Use and Service Discontinuance	☐
24.01.01	Welding Process	☐
24.02.01	Visual Inspection of Welds	☐
24.03.01	Nondestructive Testing of Welds	☐
24.04.01	Miter Joints	☐
25.01.01	Dehydration: Operate/Maintain Liquid Knock-out	☐
25.01.02	Dehydration: Maintain/Repair Gas Fired Dehydration System Controls	☐
25.01.03	Dehydration: Operate/Maintain Gas Dehydration System	☐
25.01.04	Dehydration: Start-up/Shutdown of Dehydration System	☐
25.01.05	Dehydration: Troubleshoot/Repair Gas Dehydration System	☐
25.01.06	Gas Treatment: Read/Verify/Maintain Operating Parameters for Gas Processing/Amine System	☐
25.01.07	Gas Treatment: Troubleshoot/Correct Gas Processing/Amine System	☐
25.01.08	Dehydration: Maintain/Repair Gas Fired Mole Sieve Dehydration System Controls	☐
25.01.09	Dehydration: Operate/Maintain Gas Fired Mole Sieve Dehydration System	☐
25.01.10	Dehydration: Start-up/Shutdown of Mole Sieve Dehydration System	☐
25.01.11	Dehydration: Troubleshoot/Repair Mole Sieve Dehydration System	☐
27.01.01	Gas Control	☐

Attachment 2

KINDER MORGAN

LOOK BACK DATABASE

Compression

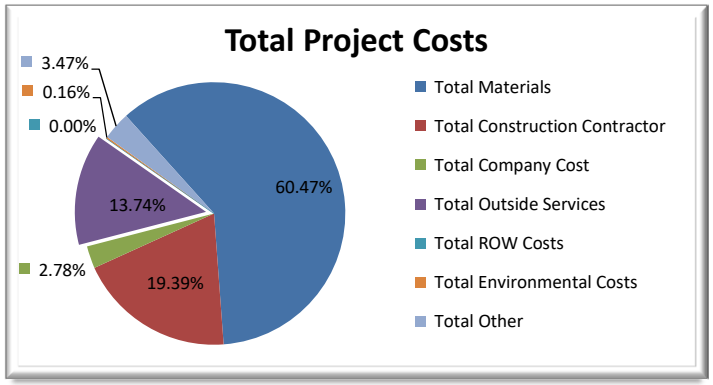
COMPRESSION

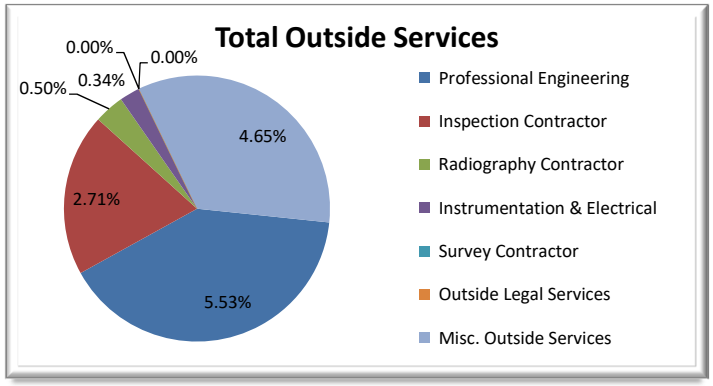
REGION		
UNION STATUS		
FERC STATUS		
ENTITY		
COMPRESSOR TYPE	Siemens EMD	
HORSE POWER	10500	17000

Selected Compression Projects: 1

Acct Category	$	%	D+C %
Total Materials	**$11,547,176**	**60.47%**	**62.57%**
Total Construction Contractor	**$3,701,897**	**19.39%**	**20.06%**
Total Company Cost	**$530,452**	**2.78%**	**2.87%**
Professional Engineering	$1,056,568	5.53%	5.73%
Inspection Contractor	$518,259	2.71%	2.81%
Radiography Contractor	$95,028	0.50%	0.51%
Instrumentation & Electrical	$65,427	0.34%	0.35%
Survey Contractor	$0	0.00%	0.00%
Outside Legal Services	$0	0.00%	0.00%
Misc. Outside Services	$887,962	4.65%	4.81%
Total Outside Services	**$2,623,244**	**13.74%**	**14.21%**
ROW Contractor	$0	0.00%	0.00%
ROW & Damages	$0	0.00%	0.00%
Total ROW Costs	**$0**	**0.00%**	**0.00%**
Environmental Contractor	$0	0.00%	0.00%
Permits & Fees	$31,146	0.16%	0.17%
Total Environmental Costs	**$31,146**	**0.16%**	**0.17%**
Gas Pack and Purge	$21,358	0.11%	0.12%
Overhead	$0	0.00%	
AFUDC	$640,926	3.36%	
Contingency	$0	0.00%	0.00%
Total Other	**$662,283**	**3.47%**	**0.12%**
Project Total	**$19,096,198**	**100.00%**	**100.00%**

Total Project All-In ($/HP)	**$1,469**





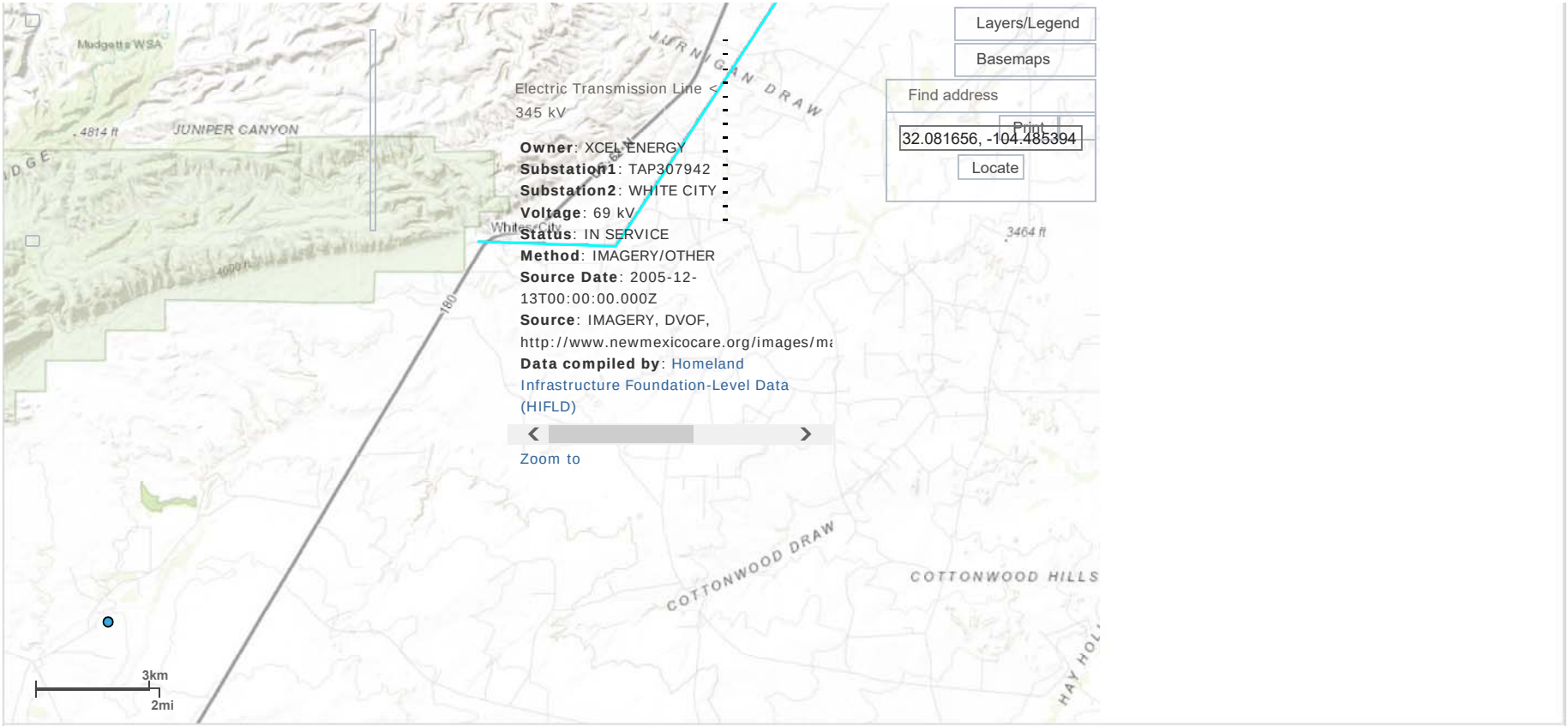
U.S. Energy Information Administration

U.S. States

State Profiles and Energy Estimates

Newly released in Beta: State Energy Portal featuring customizable dashboards and more state data.

U.S. Energy Mapping System



❖ Layer information and map data

Map questions, comments and suggestions: mapping@eia.gov

Related Maps

- U.S. Energy Mapping System
- Energy Disruptions
- Flood Vulnerability
- State Energy Profiles
- Gulf of Mexico Fact Sheet
- Major Oil and Gas Plays

KINDER MORGAN

Delivering Energy to Improve Lives

February 23, 2020

Mr. Michael Baca
Control Strategies Manager
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

El Paso Natural Gas Company, L.L.C. (EPNG)
Company-Specific Interest Rate Utilized in Regional Haze Four-Factor Analyses

Dear Mr. Baca:

The attached sheet, entitled "El Paso Natural Gas Company, L.L.C., Debt Capital, For the Twelve Months Ending December 31, 2019, as adjusted" shows a weighted average cost of debt of 8.53%. This weighted average cost of debt will be published in EPNG's Federal Energy Regulatory Commission (FERC) Form 2 filing for the year ended 2020 and will be publicly available. However, we do not expect this to be published until April 2021, and therefore this information should be treated as confidential business information, not subject to public review under N.M. Stat. Ann § 14-2-1 (H).

The most recent publicly available EPNG Form 2 filing for calendar year 2019 shows a cost of debt of 8.55%, which is based on EPNG's year-ended 2018 capital structure. This filing can be found at https://elibrary.ferc.gov/eLibrary/search by entering "4/29/2020" for the date range and entering "El Paso Natural Gas Form 2" in the Keyword Search field. The relevant data are located on pages 218a and pages 256-260 of the document. The methodology used to calculate this 8.55% cost of debt for the year ended 2018 is consistent with that used to calculate the 8.53% cost of debt for the year ended 2019 included in the attached sheet.

Sincerely,

David P. Michels
Chief Financial Officer

CBI Attachment Omitted

From:	Naqvi, Zainab
To:	Baca, Michael, NMENV; Mehdizadeh, Fariba; Nolting, Leslie R; Ray, Travis
Cc:	Singleton,Kerwin, NMENV; Zyla, Rhett, NMENV; Jones, Mark, NMENV; Butt, Neal, NMENV
Subject:	[EXT] RE: Kinder Morgan/EPNG Four-factor Analyses Follow-up and Discussion
Date:	Wednesday, September 9, 2020 3:17:27 PM
Attachments:	NMED Electric HP Capital Cost-R2.xlsx Base Cost Estimate - Centrifugal.pdf Base Cost Estimate - Recip.pdf

Michael,

Attached you will find the total costs associated with the replacement of the existing units with units with Electric Motor Drives (EMDs). These estimates are based on projects that have been completed within the company and are considered a +/- 25% reflection of the proposed projects.

The breakdown of the costs associated with the unit replacements have also been included (see attached PDF documents). The scope was built by estimating the cost of replacement turbines and engines, backing out the turbine/engine components, and adding in the EMDs. This was done to meet the NMED proposed timeline for the cost estimates.

The cost to provide sufficient utility to the stations has also been included in the capital costs. These were derived by evaluating the nearest power sources, and estimated the costs for a new substation and total power for each site.

The O&M costs for each facility were estimated based existing KM assets. These include operations and maintenance costs for an existing EMD facility (detailed in the O&M spreadsheet), as well as annual cost of utility.

Also, as you can see from the estimates, in all three facilities, the existing units were replaced with two equal sized EMD units. This was because EPNG needs to have redundancy in the system in order to maintain availability of the compressor station in the event of a unit failure (rather than one large unit). For Pecos River and Blanco A, due to the fact that the numbers of replacement units do not match the current numbers of units at each facility, the total emissions from the site were divided by the total cost of each project to derive the cost/ton. We took the same approach with Washington Ranch, though the replacement units would match the current units, in order to maintain consistency.

KM requests a phone call with the NMED to discuss these numbers, as well as path forward for the later September submittal. As stated, the attached numbers reflect a 25% margin of error; with a more precise effort, we could get the margin of error down to 10%, but it will be labor intensive on our end. Considering the cost per ton of the units at this time, KM would like to discuss the need for the effort to refine our estimates. We can complete the full four-factor analysis on the current proposed costs.

KM will continue to work on providing the answers to the outstanding questions prior to the end of the month.

Please let me know about the call!
Thanks,
-Zainab

Zainab Naqvi
Air Permitting and Compliance
KINDER MORGAN
Natural Gas Pipelines
Office: 713-420-1841 x31841
Cell: 832-607-3115
Zainab_Naqvi@kindermorgan.com

Project Name: **EPNG HP Replacement with Centrifugal**

Baseline cost to replace existing compression at EPNG facilities

User input limited to these areas.

Version date: 12/13/2019

Enter Today's Date:	9/8/20	Company Name:	El Paso Natural Gas Company
Project State:	New Mexico	Project Type:	Sustaining
Project Region:	5-West (See Region Map Tab)	Tax Gross-Up:	0.00%
Union or Non-Union:	Non-Union		
Projected In Service date:	Feb-22		

Existing or Grassroots Facility:	Existing		
How Many Additional Units?	2		
Largest Additional Unit?	Taurus 70 (11,110 HP)	11,110	ISO HP (Not De-rated)
Second Unit?	Taurus 70 (11,110 HP)	11,110	ISO HP (Not De-rated)
N/A	Taurus 70 (11,110 HP)	0	ISO HP (Not De-rated)
N/A	Taurus 70 (11,110 HP)	0	ISO HP (Not De-rated)
N/A	Centaur 40 (4,700 HP)	0	ISO HP (Not De-rated)
		22,220	Total Project HP

	ML#1	ML#2	ML#3	ML#4	ML#5	ML#6
Size of Mainline to Tie Into:						
Length from Mainline Tie-In to CS Facility (Lateral Length):						
			Tie-In's Used for estimate:			
# of Mainline Tie-Ins (Grassroots Only)? 0	0	0	0	0	0	0
			Tie-In Lateral Lengths Used for estimate:			
Inlet Suction/Outlet Discharge Line Header Size? 30-Inch	0	0	0	0	0	0

Facility Required to be on Platform (Marsh)?	N
# of Filter Separators (Per Compressor Unit)?	2
# of Gas Cooling Bays (Per Compressor Unit)?	3
Include Cost for New Standby Generator?	N
Cost for New Power to Site GR Only ($100k)?	N
Cost for New Site Land Acquisition GR Only ($360k)?	N
Winter (Cold) / Desert (Hot) Const. (Y/N):	Y (Northern Construction Nov - Mar) (Desert Construction May - Sept)
Contingency Rate:	10%
Company Overhead Rate:	0.0%

AFUDC Debt:	3.23%	(Direct Cost + Contingency) in today's dollars (unescalated):	$49,659,060	$2,235 $/HP (D+C Only)
AFUDC Equity:	7.52%	Cost in today's dollars (unescalated):	**$52,693,689**	$2,371 $/HP (All In)
Escalation Factors (APR):	3.1% Material (Compressor NOT included)	Cost escalation (to inservice date):	$1,032,446	$46 $/HP (All In)
	3.1% Other	Cost in escalated dollars (to inservice date):	**$53,726,135**	$2,418 $/HP (All In)

Notes:

Major Material Included in estimate:
- Compressor Building, Control Building, Cathodic Protection
- Compressed Air System & MCC

Other Assumptions:
- 3rd Party Engineering & Drafting
- 3rd Party Inspection
- Gas Loss is NOT included, Line(s) assumed to be down at the time of Tie-In(s)

KINDER MORGAN

PROJECT NAME	**Turbine Compressor Station**		
COMPANY NAME	El Paso Natural Gas Company	**COMPANY NO.**	5205
REQUESTED BY		**PREPARED BY**	-
ESTIMATE NO.	CE100	**ORIGINAL EST. DATE**	09/08/20
REVISION NO.	-	**CONSTRUCTION CONTINGENCY**	10%
REVISION DATE		**OVERHEAD**	0%
PROJECT MANAGER		**AFUDC RATE (Debt / Equity)**	Debt: 3.02% / Equity: 6.97%
STATE	New Mexico	**TAX GROSS UP**	0.00%
COUNTY		**PROJECT TYPE**	Sustaining
		IN-SERVICE	Feb-22
		ESTIMATE ACCURACY LEVEL	Class 5

HP Rating =	11,110	11,110	0	0	0
Cost Per HP (Direct + Contingency) =	$2,501	$1,969	#DIV/0!	#DIV/0!	#DIV/0!

ESTIMATE SUMMARY

	Taurus 70 (11,110 HP)	Taurus 70 (11,110 HP)	Taurus 70 (11,110 HP)	Taurus 70 (11,110 HP)	Centaur 40 (4,700 HP)	TOTAL
MATERIAL (INCL SALES TAX)	$ 11,647,700	$ 11,620,400				$ 23,268,100
COMPANY LABOR COST	$ 356,900	$ 314,900				$ 671,800
PM, ENG, LAND, ENVIRO - EXPENSE	$ 139,000	$ 127,900				$ 266,900
PRIMARY CONSTRUCTION CONTRACTOR	$ 10,737,700	$ 6,468,500				$ 17,206,200
SECONDARY CONTRACTOR	$ 456,700	$ 106,900				$ 563,600
PROFESSIONAL ENGINEERING	$ 649,900	$ 436,900				$ 1,086,800
INSPECTION SERVICES	$ 847,400	$ 484,300				$ 1,331,700
RADIOGRAPHY SERVICES	$ 26,200	$ 20,600				$ 46,800
ENVIRONMENTAL CONTRACTOR	$ 228,700	$ 185,000				$ 413,700
ELECTRICAL & INSTRUMENTATION	$ -	$ -				$ -
RIGHT OF WAY CONTRACTOR	$ 23,800	$ 14,000				$ 37,800
SURVEY CONTRACTOR	$ 59,700	$ 46,900				$ 106,600
OUTSIDE LEGAL SERVICES	$ 23,800	$ 23,800				$ 47,600
ROW & DAMAGES	$ 60,000	$ 37,000				$ 97,000
PERMIT FEES	$ -	$ -				$ -
GAS LOSS	$ -	$ -				$ -
SUBTOTAL	$ 25,257,500	$ 19,887,100				$ 45,144,600
CONSTRUCTION CONTINGENCY	$ 2,525,750	$ 1,988,710				$ 4,514,460
AFUDC	$ 1,646,242	$ 1,388,387				$ 3,034,629
SUBTOTAL	$ 29,429,492	$ 23,264,197				$ 52,693,689
CAPITALIZED OVERHEAD (BURDEN)	$ -	$ -				$ -
TAX GROSS-UP	$ -	$ -				$ -
ESCALATION	$ 601,176	$ 431,271				$ 1,032,446
RISK INSURANCE	$ -	$ -				$ -
ESTIMATED TOTAL COST	**$ 30,030,667**	**$ 23,695,468**				**$ 53,726,135**
Price/Ton:						
(If Applicable) Escalated Price/Ton:						
Contingency:	10%	10%	10%	10%	10%	
In-Service Date:	Feb-22	Feb-22	Feb-22	Feb-22	Feb-22	

ASSUMPTIONS

Include (Yes/No)	Assumptions	
Yes	See Assumptions Tab	

Revision	Date	Notes	Approval	Name	Date
			Project Manager		
			Project Manager Director		
			Project Controls		
			Vice President		

AUTHORITY LEVELS:	
< $25,000,000	PM, PM Director, Project Controls
> $25,000,000	PM, PM Director, Project Controls, VP

Escalation Rates $FV=PV(1+i)^n$	
Material:	3.1%
Other:	3.1%

Project Name: **EPNG HP Replacement with Recip**

Baseline cost to replace existing compression at EPNG facilities

User input limited to these areas.

Version date: 12/13/2019

Enter Today's Date:	9/8/20	Company Name:	El Paso Natural Gas Company
Project State:	New Mexico	Project Type:	Sustaining
Project Region:	5-West (See Region Map Tab)	Tax Gross-Up:	0.00%
Union or Non-Union:	Non-Union		
Projected In Service date:	Feb-22		

Existing or Grassroots Facility:	Existing		
How Many Additional Units?	2		
Largest Additional Unit?	CAT G3616 (5,000 HP)	5,000	ISO HP (Not De-rated)
Second Unit?	CAT G3616 (5,000 HP)	5,000	ISO HP (Not De-rated)
N/A	Waukesha 7044 (1,680 HP)	0	ISO HP (Not De-rated)
N/A	Waukesha L5794 (1,380 HP)	0	ISO HP (Not De-rated)
N/A	CAT G3608 (2,500 HP)	0	ISO HP (Not De-rated)
		10,000	Total Project HP

Winter (Cold) / Desert (Hot) Const. (Y/N):	Y	(Northern Construction Nov - Mar) (Desert Construction May - Sept)
Facility Required to be on Platform (Marsh)?	N	
Contingency Rate:	10%	
Company Overhead Rate:	0.0%	

AFUDC Debt:	3.23%		(Direct Cost + Contingency) in today's dollars (unescalated):	$29,764,790	$2,976 $/HP (D+C Only)
AFUDC Equity:	7.52%		Cost in today's dollars (unescalated):	**$31,672,754**	$3,167 $/HP (All In)
Escalation Factors (APR):	3.1%	Material (Compressor NOT included)	Cost escalation (to inservice date):	$595,678	$60 $/HP (All In)
	3.1%	Other	Cost in escalated dollars (to inservice date):	**$32,268,432**	$3,227 $/HP (All In)

Notes:

Major Material Included in estimate:
- Compressor Building, Control Building, Standby Generator, Cathodic Protection
- Compressed Air System, MCC, Gas Cooling & Filter Separation.

Other Assumptions:
- 3rd Party Engineering & Drafting
- 3rd Party Inspection
- $360k Land Acquisition
- $100k Power Assumed

KINDER MORGAN

PROJECT NAME	**Greenfield Compressor Station (Grassroots)**		
COMPANY NAME	El Paso Natural Gas Company	**COMPANY NO.**	5205
REQUESTED BY		**PREPARED BY**	-
ESTIMATE NO.	CE100	**ORIGINAL EST. DATE**	09/08/20
REVISION NO.	-	**CONSTRUCTION CONTINGENCY**	10%
REVISION DATE		**OVERHEAD**	0%
PROJECT MANAGER		**AFUDC RATE (Debt / Equity)**	Debt: 3.02% / Equity: 6.97%
STATE	New Mexico	**TAX GROSS UP**	0.00%
COUNTY		**PROJECT TYPE**	Sustaining
		IN-SERVICE	Feb-22
		ESTIMATE ACCURACY LEVEL	Class 5

HP Rating =	5,000	5,000	0	0	0
Cost Per HP (Direct + Contingency) =	$3,273	$2,680	#DIV/0!	#DIV/0!	#DIV/0!

ESTIMATE SUMMARY

	CAT G3616 (5,000 HP)	CAT G3616 (5,000 HP)	Waukesha 7044 (1,680 HP)	Waukesha L5794 (1,380 HP)	CAT G3608 (2,500 HP)	TOTAL
MATERIAL (INCL SALES TAX)	$ 8,250,500	$ 8,223,200				$ 16,473,700
COMPANY LABOR COST	$ 266,900	$ 235,500				$ 502,400
PM, ENG, LAND, ENVIRO - EXPENSE	$ 111,500	$ 100,400				$ 211,900
PRIMARY CONSTRUCTION CONTRACTOR	$ 4,396,600	$ 2,528,600				$ 6,925,200
SECONDARY CONTRACTOR	$ 305,500	$ 106,900				$ 412,400
PROFESSIONAL ENGINEERING	$ 588,200	$ 395,800				$ 984,000
INSPECTION SERVICES	$ 659,000	$ 361,600				$ 1,020,600
RADIOGRAPHY SERVICES	$ 20,600	$ 15,600				$ 36,200
ENVIRONMENTAL CONTRACTOR	$ 156,200	$ 124,000				$ 280,200
ELECTRICAL & INSTRUMENTATION	$ -	$ -				$ -
RIGHT OF WAY CONTRACTOR	$ 14,000	$ 9,700				$ 23,700
SURVEY CONTRACTOR	$ 46,900	$ 34,100				$ 81,000
OUTSIDE LEGAL SERVICES	$ 23,800	$ 23,800				$ 47,600
ROW & DAMAGES	$ 36,000	$ 24,000				$ 60,000
PERMIT FEES	$ -	$ -				$ -
GAS LOSS	$ -	$ -				$ -
SUBTOTAL	$ 14,875,700	$ 12,183,200				$ 27,058,900
CONSTRUCTION CONTINGENCY	$ 1,487,570	$ 1,218,320				$ 2,705,890
AFUDC	$ 1,024,276	$ 883,688				$ 1,907,964
SUBTOTAL	$ 17,387,546	$ 14,285,208				$ 31,672,754
CAPITALIZED OVERHEAD (BURDEN)	$ -	$ -				$ -
TAX GROSS-UP	$ -	$ -				$ -
ESCALATION	$ 339,202	$ 256,476				$ 595,678
RISK INSURANCE	$ -	$ -				$ -
ESTIMATED TOTAL COST	**$ 17,726,748**	**$ 14,541,684**				**$ 32,268,432**

Price/Ton:					
(If Applicable) Escalated Price/Ton:					
Contingency:	10%	10%	10%	10%	10%
In-Service Date:	Feb-22	Feb-22	Feb-22	Feb-22	Feb-22

ASSUMPTIONS

Include (Yes/No)	Assumptions	
Yes	See Assumptions Tab	

Revision	Date	Notes	Approval	Name	Date
			Project Manager		
			Project Manager Director		
			Project Controls		
			Vice President		

AUTHORITY LEVELS:	
< $25,000,000	PM, PM Director, Project Controls
> $25,000,000	PM, PM Director, Project Controls, VP

Escalation Rates $FV=PV(1+i)^n$	
Material:	3.1%
Other:	3.1%

Estimate Form Revision 8.3 (Draft) 04/05/16

Location	Unit ID	Make	Model	Site HP	2016 NOx Emissions
Blanco A	6526-A-01	**Cooper**	GMV-10TF	913	73.7107
	6526-A-02	**Cooper**	GMV-10TF	913	0.0246
	6526-A-03	**Cooper**	GMV-10TF	913	54.9147
	6526-A-04	**Cooper**	GMV-10TF	913	1.0928
	6526-A-05	**Cooper**	GMV-10TF	913	3.0811
	6526-A-06	**Cooper**	GMV-10TF	913	0.6135
	6526-A-07	**Cooper**	GMV-10TF	913	65.3411
	6526-A-08	**Cooper**	GMV-10TF	913	0.0192
	6526-A-09	**Cooper**	GMV-10TF	913	27.3820
	6526-A-10	**Cooper**	GMV-10TF	913	0.0192
	6526-A-11	**Cooper**	GMV-10TF	913	48.2534
	6526-A-12	**Cooper**	GMV-10TF	913	0.0164
	6526-A-13	**Cooper**	GMV-10TF	913	82.0612
	6526-A-14	**Cooper**	GMV-10TF	913	0.0192
				Blanco Total	356.549

Assumed Discount Rate - "r"		8.53%
Total Capital Outlay (TCI) for Electric compression (each) - "P"	$	54,331,872
Life Expectancy of Electric compression (years) - "n"		25
Annualized TCI - "A"	$	5,322,114
Annual O&M Costs	$	5,834,047
Total Annual Costs	$	11,156,161
Baseline NOx Emissions (tpy)		356.55
Emissions with Electric compression (tpy)		0
Emissions Reduction (tpy)		356.55
% Reduction		100.0%
Cost: $/yr-ton	$	31,289

$$A = P\frac{r(1+r)^n}{(1+r)^n - 1}$$

Location	Unit ID	Make	Model	Site HP	Emissions (2016-2018 Avg AEERS)	Emissions (2016-2018 Updated EI)
Pecos River	6560-A-01	**GE**	M3712R A	5,650	102.80	31.34
	6560-A-02	**GE**	M3712R A	5,650	175.56	82.70
	6560-A-03	**GE**	M3712R A	5,650	178.71	78.68
				Pecos River Emissions Total	457.07	192.72

	Emissions (2016-2018 Avg AEERS)		Emissions (2016-2018 Updated EI)	
Assumed Discount Rate - "r"	8.53%		8.53%	
Total Capital Outlay (TCI) for Electric compression (each) - "P"	$	60,850,932	$	60,850,932
Life Expectancy of Electric compression (years) - "n"	25		25	
Annualized TCI - "A"	$	5,960,693	$	5,960,693
Annual O&M Costs	$	5,834,047	$	5,834,047
Total Annual Costs	$	11,794,740	$	11,794,740
Baseline NOx Emissions (tpy)	457.07		192.72	
Emissions with Electric compression (tpy)	0		0	
Emissions Reduction (tpy)	457.07		192.72	
% Reduction	100.0%		100.0%	
Cost: $/yr-ton	$	25,805	$	61,201

$$A = P\frac{r(1+r)^n}{(1+r)^n - 1}$$

Location	Unit ID	Make	Model	Site HP	Emissions (2016-2018 Avg AEERS)
Washington Ranch	6595-A-01	**Cooper**	12Q155HC2	4,500	34.55
	6595-B-02	**Cooper**	12Q155HC2	4,500	32.34
			Washington Ranch Emissions Total		66.89

Assumed Discount Rate - "r"		8.53%
Total Capital Outlay (TCI) for Electric compression (each) - "P"	$	38,905,023
Life Expectancy of Electric compression (years) - "n"		25
Annualized TCI - "A"	$	3,810,967
Annual O&M Costs	$	5,834,047
Total Annual Costs	$	9,645,014
Baseline NOx Emissions (tpy)		66.89
Emissions with Electric compression (tpy)		0
Emissions Reduction (tpy)		66.89
% Reduction		100.0%
Cost: $/yr-ton	$	144,192

$$A = P\frac{r(1+r)^n}{(1+r)^n - 1}$$

NMED HP Replacement Request		EPNG-Blanco					EPNG-Pecos River					EPNG-Washington Ranch				
		Cost	Year	Qty	Total Cost	Source	Cost	Year	Qty	Total Cost	Source	Cost	Year	Qty	Total Cost	Source
Base Cost Estimate		$52,693,689	2020	1	$52,693,689	Cost Estimating Group: Conceptual Estimating Tool	$52,693,689	2020	1	$52,693,689	Cost Estimating Group: Conceptual Estimating Tool	$31,672,754	2020	1	$31,672,754	Cost Estimating Group: Conceptual Estimating Tool
Turbine Costs	Engine & Compressor	$6,250,000	2020	2	($12,500,000)	Dec. 2019 Cost Estimating Template	$6,250,000	2020	2	($12,500,000)	Dec. 2019 Cost Estimating Template	$3,900,000	2020	2	($7,800,000)	Dec. 2019 Cost Estimating Template
	Engine Exhaust	$350,000	2020	2	($700,000)	Dec. 2019 Cost Estimating Template	$350,000	2020	2	($700,000)	Dec. 2019 Cost Estimating Template	$350,000	2020	2	($700,000)	Dec. 2019 Cost Estimating Template
	Fuel Skid	$318,597	2020	1	($318,597)	Dec. 2019 Cost Estimating Template	$318,597	2020	1	($318,597)	Dec. 2019 Cost Estimating Template	$318,597	2020	1	($318,597)	Dec. 2019 Cost Estimating Template
	Turbine Cost Subtotal	**Removed from Base Cost ----->**			**($13,518,597)**		**Removed from Base Cost ----->**			**($13,518,597)**		**Removed from Base Cost ----->**			**($8,818,597)**	
EMD Costs	VFD + EMD + Gear + Compressor	$3,900,000	2017	2	$8,523,271	7,000 HP Solar EMD / C45 budgetary pricing - 2017	$4,420,560	2017	2	$9,660,931	Solar EMD / C45 budgetary pricing - 2017 --> scaled to to 9,000 HP	$3,448,234	2017	2	$7,535,957	D-R EMD / HHE firm pricing - 2017 with 9,000 HP motors
	E-House	$500,000	2020	2	$1,000,000	Rule of thumb based on past projects	$500,000	2020	2	$1,000,000	Rule of thumb based on past projects	$500,000	2020	1	$500,000	Rule of thumb based on past projects. Only need one E-House & VFD for the facility.
	Motor Ventilation System	$249,956	2019	2	$514,909	AAF quote for EPNG-Waha	$249,956	2019	2	$514,909	AAF quote for EPNG-Waha	$249,956	2019	2	$514,909	AAF quote for EPNG-Waha
	Electric Sub-Station	$3,000,000	2020	1	$3,000,000	Rule of thumb based on past projects	$3,000,000	2020	1	$3,000,000	Rule of thumb based on past projects	$3,000,000	2020	1	$3,000,000	Rule of thumb based on past projects
	Electric Utility (per mile)	$7,062,000	2020	0.3	$2,118,600	Rule of thumb based on past projects	$500,000	2020	15	$7,500,000	Rule of thumb based on past projects	$500,000	2020	9	$4,500,000	Rule of thumb based on past projects
	EMD Cost Adders	**Added to Base Cost ----->**			**$15,156,780**		**Added to Base Cost ----->**			**$21,675,840**		**Added to Base Cost ----->**			**$16,050,866**	
Total Replacement Cost					**$54,331,872**					**$60,850,932**					**$38,905,023**	

Note: The base estimate above uses the KM-Cost Estimating Group's Developmental Cost Estimating Tool, which is based on turbine drivers. Starting here, specific turbine costs are subtracted, and specific EMD costs are added in to get an overall eelctric compression replacement cost.

Note: The base estimate above uses the KM-Cost Estimating Group's Developmental Cost Estimating Tool, which is based on turbine drivers. Starting here, specific turbine costs are subtracted, and specific EMD costs are added in to get an overall eelctric compression replacement cost.

Note: The base estimate above uses the KM-Cost Estimating Group's Developmental Cost Estimating Tool, which is based on recip drivers. Starting here, specific recip costs are subtracted, and specific EMD costs are added in to get an overall eelctric compression replacement cost.

Location	Unit ID	Make	Model	Site HP
Blanco	6526-A-01	**Cooper**	GMV-10TF	913
elev.=5,605 ft.	6526-A-02	**Cooper**	GMV-10TF	913
	6526-A-03	**Cooper**	GMV-10TF	913
	6526-A-04	**Cooper**	GMV-10TF	913
	6526-A-05	**Cooper**	GMV-10TF	913
	6526-A-06	**Cooper**	GMV-10TF	913
	6526-A-07	**Cooper**	GMV-10TF	913
	6526-A-08	**Cooper**	GMV-10TF	913
	6526-A-09	**Cooper**	GMV-10TF	913
	6526-A-10	**Cooper**	GMV-10TF	913
	6526-A-11	**Cooper**	GMV-10TF	913
	6526-A-12	**Cooper**	GMV-10TF	913
	6526-A-13	**Cooper**	GMV-10TF	913
	6526-A-14	**Cooper**	GMV-10TF	913
			Blanco Total	**12,782**

<----Replace with 2 ea. derated 7,000 HP EMD; each equivalent to Solar Taurus 70 / C45

Location	Unit ID	Make	Model	Site HP
Pecos River	6560-A-01	**GE**	M3712R A	5,650
elev.=2,900 ft.	6560-A-02	**GE**	M3712R A	5,650
	6560-A-03	**GE**	M3712R A	5,650
			Pecos River Total	**16,950**

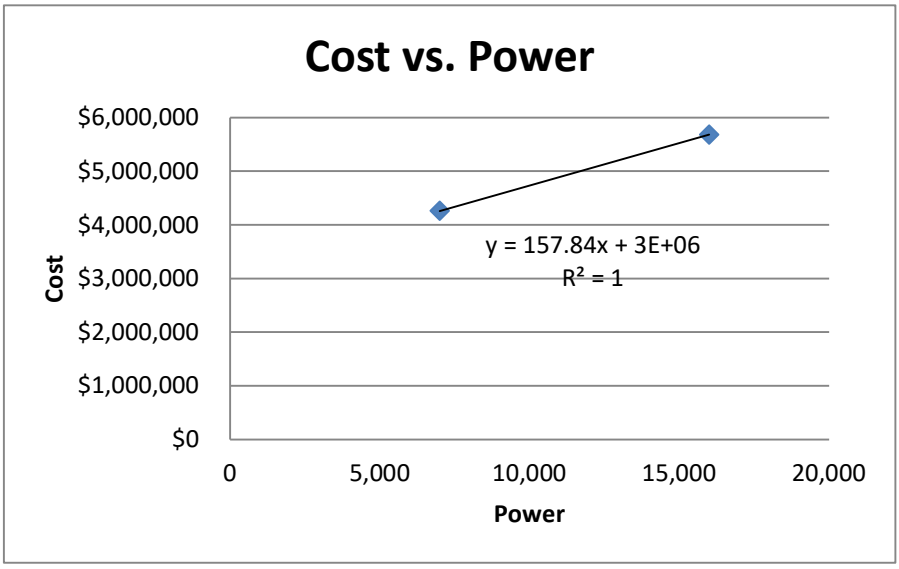
<----Replace with 2 ea. derated 10,000 HP EMD; each equivalent to Solar Taurus 70 / C45

Location	Unit ID	Make	Model	Site HP
Washington Ranch	6595-A-01	**Cooper**	12Q155HC2	4,500
elev.=3,710 ft.	6595-B-02	**Cooper**	12Q155HC2	4,500
			Washington Ranch Total	**9,000**

<----Replace with 2 ea. derated 5,000 HP EMD; each equivalent to CAT G3616

	Cost	Power
$	4,420,560	9,000

Package	Rating	Cost	Cost Year	2020 Cost
VFD+EMD+Gear+C45	7,000	$3,900,000	2017	$4,261,635
VFD+EMD+Gear+C65	16,000	$5,200,000	2017	$5,682,180
E-House+VFD+EMD+Gear+C65	19,000	$6,044,000	2019	$6,225,320



2020 and 2021 O&M budgets for TGP's Cleveland CS25
3 electric driven centrifugal compressors, total 25,600 hp
75% utilization, 60% load

TOC OMDM	TOC Desc	Sum of 2020_Budget	Sum of 2021_Budget
TOC- 100	Labor	$167,222	$180,384
TOC- 110	Labor - OT	$9,206	$9,206
	Subtotal Labor	$176,428	$189,590
TOC- 200	Employee Exp	$5,327	$5,327
TOC- 290	Training	$9,549	$9,549
TOC- 300	Material/Supplies	$260,865	$237,656
TOC- 302	Lubricants	$6,294	$6,294
TOC- 310	Oper Liquids/Chemicals/Gases	$6,920	$6,920
TOC- 350	Mechanical Parts	$86,711	$86,711
TOC- 360	Safety	$14,549	$14,549
TOC- 431	Outside Services Compression	$211,087	$211,087
TOC- 436	Outside Services Offices & Buildings	$19,515	$19,515
TOC- 500	Vehicle	$3,575	$7,233
TOC- 510	Vehicle Expense - Fuel	$1,484	$2,957
TOC- 620	Personal Property Rental	$7,274	$7,274
TOC- 700	Utilities - Gas & Water	$1,761	$1,761
TOC- 710	Non-Cellular Phones	$9,669	$9,669
TOC- 711	Cellular Phones	$1,761	$1,761
TOC- 720	Facility Electricity - Building	$895	$895
TOC- 840	Projects - Gen Business Exp	$145,663	$215,300
	Subtotal Operations	$792,898	$844,457
TOC-0000	Facility Electricity - Unit	$3,500,000	$4,800,000
	Subtotal Utility	$3,500,000	$4,800,000
	Total	$4,469,326	$5,834,047

From:	Naqvi, Zainab
To:	Baca, Michael, NMENV; Mehdizadeh, Fariba; Nolting, Leslie R; Ray, Travis
Cc:	Singleton,Kerwin, NMENV; Zyla, Rhett, NMENV; Jones, Mark, NMENV; Butt, Neal, NMENV
Subject:	[EXT] RE: Kinder Morgan/EPNG Four-factor Analyses Follow-up and Discussion
Date:	Friday, October 9, 2020 3:32:57 PM
Attachments:	EPNG 4FA Costs-Blanco A - Rev09-2020.xlsx EPNG 2019 AFUDC Rate Calc.pdf PecosRiver_EI2017_Calculations-UpdateFactors.pdf PecosRiver_EI2018_Calculations-UpdateFactors.pdf PecosRiver_EI2016_Calculations_UpdateFactors.pdf

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Michael et all,

Please see our below response in a follow-up to the items listed as pending from the September 2nd email from the NMED. We are proceeding with the understanding that our phone conversations from September 1, September 11, and September 22, and email responses on September 9 and September 30 have addressed the majority of questions from the original August 21 email. Please let us know if the NMED would like clarification on any of the current or future issues. We appreciate working with NMED through this process.

Pending Overarching:

* A company-specific interest rate for the cost of capital for the installation of air pollution equipment or lower-emitting equipment.

Attached (EPNG 2019 AFUDC Rate Calc.pdf) is the documentation for EPNG's negotiated interest rate of 8.53%. Please note that EPNG submitted and used this rate for the four-factor-analyses that were conducted and submitted in Arizona.

* The 2016-2018 emissions used by NMED in the modeling inventory and cost analysis are not representative of actual emissions. The inventories used the permitted emission rate and actual operating hours, but stack tests show that the emission rate is much lower. NMED will move forward with the modeling aspect based on the submitted information, but will discuss the use of a more representative number when making the final determination of cost effectiveness.

Concurrent with submitting this response, EPNG is submitting updated 2016 – 2018 Emission Inventory calculations for Washington Ranch Storage Facility and Pecos River Compressor Station. As discussed, the updated emission inventory is based on stack test data and is representative of actual emissions for the calendar year. We have attached the updated Pecos River emissions inventories from 2016-2018 for your review. We appreciate NMED's consideration of the updated data in their analysis.

* Kinder Morgan will provide us with some really rough estimates for electrification of the compressor units at each facility within a week (September 8) to consider for the PAC #2 modeling run. They will refine their evaluation of the technical feasibility of this control measure and the cost analysis to the extent possible by September 30.

Subsequent to our September 9, 2020 submittal, NMED indicated that no further information on replacement with electric compressors is required at this time.

* NMED will discuss the draft ozone precursor rule and how it affects facilities subject to the RH rule with our management and relay concerns regarding regulatory certainty and long-term planning and investment. Kinder Morgan will be developing and submitting written comments on the draft rule.

EPNG submitted comments on the draft ozone precursor rule on September 16, 2020. We appreciate NMED pursuing the concerns regarding the overlap of the two rules.

Pending EPNG Blanco A Compressor Station:

* Please provide O&M Costs and recalculate Total Capital Investment (TCI) with amortization.

In the attached spreadsheet ("EPNG 4FA Costs-Blanco A – Rev09-2020.xlsx"), we have revised the cost calculations, including amortization of the TCI assuming a 20-year life expectancy and the company-specific interest rate of 8.53%. We have also included annual O&M costs, which were previously omitted. Please note that our calculations include the 2016 emissions as baseline, consistent with our previous analysis. Note there are two tabs to the spreadsheet, with our Options 1 and 2 on the first tab, and Option 3 on the second tab.

* Option 3 for LEC indicates that 9 units will be uprated, and 5 units will be retired. However you provided cost per ton value estimates for all 14 engines. Shouldn't the retired units be removed from Option 3 in Table 2: Cost Effectiveness Based on 2016 Emissions Inventory in your Four Factor Analysis? Please provide clarification on which engines would hypothetically be retired (e.g., A02, A05, A05, A08, A10?).

It is correct that for Option 3, the costs would be split amongst 9 units rather than 14 units. Since Option 3 would require a facility-wide approach (including the uprating of 9 units and retirement of 5 units) to provide equivalent facility-wide horsepower, we have accumulated the costs and emission reductions on a facility-wide basis. This eliminates the need to specify which units would be retired although presumably the units with limited utilization would be selected for retirement. The option remains economically infeasible at a cost of over $10,000 per ton on a facility-wide basis.

* Please provide estimates to determine if replacing the engines with electric compressors is cost prohibitive.

Subsequent to our September 9, 2020 submittal, NMED has indicated that no further information on replacement with electric compressors is required at this time.

*It is unclear how Energy and Non-Air Quality Environmental Impacts are different from normal operations. Please provide specifics to document the reasoning for those impacts listed.

The proposed emission reduction strategies include high-pressure fuel injection systems, which take electricity to operate over and above the electricity usage of the facility in its current configuration. The project would also generate waste and additional temporary combustion emissions from equipment during the construction process. Option 2 includes oxidation catalysts that are also a source of waste.

Pending El Paso Washington Ranch:

*Why are the Low Emission Control reduction efficiencies presented by EPNG so variable 27%-82%? Can you provide more information on the actual LEC performance on the engines in the analysis and how it may potentially be improved to provide better efficiency, if possible? If other LEC packages are available for this facility, provide cost estimates with the control technology.

The Clean Burn Technologies (CBTs) NOx emissions improvement range is not specific to the Cooper-Bessemer 12Q155HC2 engines at Washington Ranch; rather it is inclusive of all slow-speed, two-cycle lean burn engines. Engines from different OEM's, e.g. Cooper-Bessemer, Clark, Worthington, Ingersoll-Rand, and even model variations from the same OEM, contain design differences which impact how the engine breaths, the compression ratio (relates to overall combustion pressure/temperature), and how efficient it is at converting the fuel to energy. It is variations in engine performance rather than variations in the performance of aftermarket control technology that drive the variations in NOx endpoints.

For the existing Cooper-Bessemer units located at Washington Ranch, the various CBTs were installed over the life of the units. Each proposed CBT installation (turbocharger, advanced ignition system, Pre-Combustion Chambers (PCC) System, High Pressure Fuel Injection, and an Automatic Balancing Platform) resulted in a range of potential emissions improvement.

If there are any additional questions, please don't hesitate to reach out to Fariba Mehdizadeh, Leslie Nolting, or Travis Ray regarding clarifications or concerns.

Thanks,
-Zainab

EPNG - Blanco A CS 4-Factor Analysis

Blanco A CS Equipment Amortization

Annualized TCI - "A" Equation

$$A = P\frac{r(1+r)^n}{(1+r)^n - 1}$$

NOx Target	Option 1 3.0 g/bhp-hr	Option 2 1.0 g/bhp-hr
Total Capital Investment (TCI) for control equip (each) - "P"	$ 1,884,728	$ 2,975,000
Assumed Discount Rate - "r"	8.53%	8.53%
Life Expectancy of control equip (years) - "n"	20	20
AO1		
Total Capital Investment (TCI) for control equip (each) - "P"	$ 1,884,728	$ 2,975,000
Life Expectancy of control equip (years) - "n"	20	20
Annualized TCI - "A"	$ 199,596	$ 315,058
Annual O&M Costs	$ 49,324	$ 52,010
Total Annual Costs	$ 248,920	$ 367,068
Baseline NOx Emissions (tpy)	73.71	73.71
Emissions with controls (tpy)	21.00	7.00
Emissions Reduction (tpy)	52.71	66.71
% Reduction	71.5%	90.5%
Cost: $/yr-ton	$ 4,722	$ 5,502
AO2		
Total Capital Investment (TCI) for control equip (each) - "P"	$ 1,884,728	$ 2,975,000
Life Expectancy of control equip (years) - "n"	20	20
Annualized TCI - "A"	$ 199,596	$ 315,058
Annual O&M Costs	$ 49,324	$ 52,010
Total Annual Costs	$ 248,920	$ 367,068
Baseline NOx Emissions (tpy)	0.025	0.025
Emissions with controls (tpy)	0.007	0.002
Emissions Reduction (tpy)	0.02	0.02
% Reduction	71.5%	90.5%
Cost: $/yr-ton	$ 13,923,672	$ 16,223,415
AO3		
Total Capital Investment (TCI) for control equip (each) - "P"	$ 1,884,728	$ 2,975,000

Life Expectancy of control equip (years) - "n"	20	20
Annualized TCI - "A"	$ 199,596	$ 315,058
Annual O&M Costs	$ 49,324	$ 52,010
Total Annual Costs	$ 248,920	$ 367,068
Baseline NOx Emissions (tpy)	54.915	54.915
Emissions with controls (tpy)	15.65	5.22
Emissions Reduction (tpy)	39.27	49.70
% Reduction	71.5%	90.5%
Cost: $/yr-ton	$ 6,339	$ 7,386
AO4		
Total Capital Investment (TCI) for control equip (each) - "P"	$ 1,884,728	$ 2,975,000
Life Expectancy of control equip (years) - "n"	20	20
Annualized TCI - "A"	$ 199,596	$ 315,058
Annual O&M Costs	$ 49,324	$ 52,010
Total Annual Costs	$ 248,920	$ 367,068
Baseline NOx Emissions (tpy)	1.093	1.093
Emissions with controls (tpy)	0.31	0.10
Emissions Reduction (tpy)	0.78	0.99
% Reduction	71.5%	90.5%
Cost: $/yr-ton	$ 318,474	$ 371,075
AO5		
Total Capital Investment (TCI) for control equip (each) - "P"	$ 1,884,728	$ 2,975,000
Life Expectancy of control equip (years) - "n"	20	20
Annualized TCI - "A"	$ 199,596	$ 315,058
Annual O&M Costs	$ 49,324	$ 52,010
Total Annual Costs	$ 248,920	$ 367,068
Baseline NOx Emissions (tpy)	3.081	3.081
Emissions with controls (tpy)	0.88	0.29
Emissions Reduction (tpy)	2.20	2.79
% Reduction	71.5%	90.5%
Cost: $/yr-ton	$ 112,980	$ 131,641
AO6		
Total Capital Investment (TCI) for control equip (each) - "P"	$ 1,884,728	$ 2,975,000
Life Expectancy of control equip (years) - "n"	20	20
Annualized TCI - "A"	$ 199,596	$ 315,058
Annual O&M Costs	$ 49,324	$ 52,010
Total Annual Costs	$ 248,920	$ 367,068

Baseline NOx Emissions (tpy)	0.613	0.613
Emissions with controls (tpy)	0.17	0.06
Emissions Reduction (tpy)	0.44	0.55
% Reduction	71.5%	90.5%
Cost: $/yr-ton	$ 567,850	$ 661,640
AO7		
Total Capital Investment (TCI) for control equip (each) - "P"	$ 1,884,728	$ 2,975,000
Life Expectancy of control equip (years) - "n"	20	20
Annualized TCI - "A"	$ 199,596	$ 315,058
Annual O&M Costs	$ 49,324	$ 52,010
Total Annual Costs	$ 248,920	$ 367,068
Baseline NOx Emissions (tpy)	65.34	65.34
Emissions with controls (tpy)	18.62	6.21
Emissions Reduction (tpy)	46.73	59.14
% Reduction	71.5%	90.5%
Cost: $/yr-ton	$ 5,327	$ 6,207
AO8		
Total Capital Investment (TCI) for control equip (each) - "P"	$ 1,884,728	$ 2,975,000
Life Expectancy of control equip (years) - "n"	20	20
Annualized TCI - "A"	$ 199,596	$ 315,058
Annual O&M Costs	$ 49,324	$ 52,010
Total Annual Costs	$ 248,920	$ 367,068
Baseline NOx Emissions (tpy)	0.019	0.019
Emissions with controls (tpy)	0.005	0.002
Emissions Reduction (tpy)	0.01	0.02
% Reduction	71.5%	90.5%
Cost: $/yr-ton	$ 18,320,622	$ 21,346,599
AO9		
Total Capital Investment (TCI) for control equip (each) - "P"	$ 1,884,728	$ 2,975,000
Life Expectancy of control equip (years) - "n"	20	20
Annualized TCI - "A"	$ 199,596	$ 315,058
Annual O&M Costs	$ 49,324	$ 52,010
Total Annual Costs	$ 248,920	$ 367,068
Baseline NOx Emissions (tpy)	27.382	27.382
Emissions with controls (tpy)	7.80	2.60
Emissions Reduction (tpy)	19.58	24.78
% Reduction	71.5%	90.5%
Cost: $/yr-ton	$ 12,712	$ 14,812

A10		
Total Capital Investment (TCI) for control equip (each) - "P"	$ 1,884,728	$ 2,975,000
Life Expectancy of control equip (years) - "n"	20	20
Annualized TCI - "A"	$ 199,596	$ 315,058
Annual O&M Costs	$ 49,324	$ 52,010
Total Annual Costs	$ 248,920	$ 367,068
Baseline NOx Emissions (tpy)	0.019	0.019
Emissions with controls (tpy)	0.005	0.002
Emissions Reduction (tpy)	0.01	0.02
% Reduction	71.5%	90.5%
Cost: $/yr-ton	$ 18,320,622	$ 21,346,599

A11		
Total Capital Investment (TCI) for control equip (each) - "P"	$ 1,884,728	$ 2,975,000
Life Expectancy of control equip (years) - "n"	20	20
Annualized TCI - "A"	$ 199,596	$ 315,058
Annual O&M Costs	$ 49,324	$ 52,010
Total Annual Costs	$ 248,920	$ 367,068
Baseline NOx Emissions (tpy)	48.253	48.253
Emissions with controls (tpy)	13.75	4.58
Emissions Reduction (tpy)	34.51	43.67
% Reduction	71.5%	90.5%
Cost: $/yr-ton	$ 7,214	$ 8,405

A12		
Total Capital Investment (TCI) for control equip (each) - "P"	$ 1,884,728	$ 2,975,000
Life Expectancy of control equip (years) - "n"	20	20
Annualized TCI - "A"	$ 199,596	$ 315,058
Annual O&M Costs	$ 49,324	$ 52,010
Total Annual Costs	$ 248,920	$ 367,068
Baseline NOx Emissions (tpy)	0.016	0.016
Emissions with controls (tpy)	0.00	0.00
Emissions Reduction (tpy)	0.01	0.01
% Reduction	71.5%	90.5%
Cost: $/yr-ton	$ 21,755,738	$ 25,349,087

A13		
Total Capital Investment (TCI) for control equip (each) - "P"	$ 1,884,728	$ 2,975,000
Life Expectancy of control equip (years) - "n"	20	20

Annualized TCI - "A"	$ 199,596	$ 315,058
Annual O&M Costs	$ 49,324	$ 52,010
Total Annual Costs	$ 248,920	$ 367,068
Baseline NOx Emissions (tpy)	82.061	82.061
Emissions with controls (tpy)	23.38	7.79
Emissions Reduction (tpy)	58.68	74.27
% Reduction	71.5%	90.5%
Cost: $/yr-ton	$ 4,242	$ 4,942
A14		
Total Capital Investment (TCI) for control equip (each) - "P"	$ 1,884,728	$ 2,975,000
Life Expectancy of control equip (years) - "n"	20	20
Annualized TCI - "A"	$ 199,596	$ 315,058
Annual O&M Costs	$ 49,324	$ 52,010
Total Annual Costs	$ 248,920	$ 367,068
Baseline NOx Emissions (tpy)	0.019	0.019
Emissions with controls (tpy)	0.01	0.00
Emissions Reduction (tpy)	0.01	0.02
% Reduction	71.5%	90.5%
Cost: $/yr-ton	$ 18,320,622	$ 21,346,599

EPNG - Blanco A CS 4-Factor Analysis

Blanco A CS Equipment Amortization

Annualized TCI - "A" Equation

$$A = P\frac{r(1+r)^n}{(1+r)^n - 1}$$

	Option 3 0.5 g/bhp-hr
NOx Target	
Total Capital Investment (TCI) for control equip (9 units) - "P"	$ 25,243,538
Assumed Discount Rate - "r"	8.53%
Life Expectancy of control equip (years) - "n"	20

A01 - A14 (assumes 9 units continue to operate)	
Total Capital Investment (TCI) for control equip (9 units) - "P"	$ 25,243,538
Life Expectancy of control equip (years) - "n"	20
Annualized TCI - "A"	$ 2,673,339
Annual O&M Costs (9 units)	$ 751,302
Total Annual Costs	$ 3,424,641
Baseline NOx Emissions (tpy)	356.55
Emissions with controls (tpy)	16.93
Emissions Reduction (tpy)	339.62
% Reduction	95.3%
Cost: $/yr-ton	$ 10,084

CBI Attachment Omitted

El Paso Natural Gas Company, LLC - Pecos River Compressor Station

Turbines

Units: **A-01, A-02, A-03**
Description: **GE Regenerative Cycle Turbines (model M3712R)**

ISO Rating:	**7150**	**hp**
Fuel Heating Value:	**1031**	**Btu/scf**
Heat Input Rate:	**56.45**	**MMBtu/hr**

	A-01	A-02	A-03
Hours:	754.75	7,916.25	7,693.25
Fuel Cons. (MMscf):	40.15	306.16	305.09

Criteria Pollutant	EF	Units	Source	A-01 TPY	A-02 TPY	A-03 TPY
NOx	20.6	lb/hr	Source Test (7/12/16)*	7.785		
NOx	25.9	lb/hr	Source Test (7/24/17)		102.595	
NOx	24.8	lb/hr	Source Test (7/24/17)			95.319
CO	4.4	lb/hr	Source Test (7/12/16)*	1.645		
CO	3.4	lb/hr	Source Test (7/24/17)		13.537	
CO	3.7	lb/hr	Source Test (7/24/17)			14.194
VOC	0.002	lb/MMBtu	AP-42	0.041	0.316	0.315
SO2	0.003	lb/MMBtu	AP-42	0.062	0.473	0.472
PM	0.007	lb/MMBtu	AP-42	0.145	1.105	1.101
*Note that Unit 1 was out of service for most of 2017 and did not receive a test until 2018						
HAP Pollutants						
Acetaldehyde	4.00E-05	lb/MMBtu	AP-42	0.001	0.006	0.006
Acrolein	6.40E-06	lb/MMBtu	AP-42	0.000	0.001	0.001
Benzene	1.20E-05	lb/MMBtu	AP-42	0.000	0.002	0.002
Ethylbenzene	3.20E-05	lb/MMBtu	AP-42	0.001	0.005	0.005
Formaldehyde	7.10E-04	lb/MMBtu	AP-42	0.015	0.112	0.112
Naphthalene	1.30E-06	lb/MMBtu	AP-42	0.000	0.000	0.000
PAH	2.20E-06	lb/MMBtu	AP-42	0.000	0.000	0.000
Propylene Oxide	2.90E-05	lb/MMBtu	AP-42	0.001	0.005	0.005
Toluene	1.30E-04	lb/MMBtu	AP-42	0.003	0.021	0.020
Xylene	6.40E-05	lb/MMBtu	AP-42	0.001	0.010	0.010
			Total HAPS	0.021	0.162	0.162

Month	Year	Blowdown Volumes (MMScf)	Additional Volume (ESDs, Other) (MMSCF)	Total Volume (MMSCF)	VOC %	Gas Density (lb/scf)	Monthly VOC (Tons)
Jan	2017	0.073	0.000	0.073	1.59%	0.046	0.027
Feb	2017	0.101	0.000	0.101	1.59%	0.046	0.037
Mar	2017	0.088	0.000	0.088	1.59%	0.046	0.032
Apr	2017	0.092	0.000	0.092	1.59%	0.046	0.034
May	2017	0.070	0.000	0.070	1.59%	0.046	0.026
Jun	2017	0.021	0.000	0.021	1.59%	0.046	0.008
July	2017	0.000	0.000	0.000	1.59%	0.046	0.000
Aug	2017	0.103	0.000	0.103	1.59%	0.046	0.038
Sep	2017	0.000	0.000	0.000	1.59%	0.046	0.000
Oct	2017	0.124	0.000	0.124	1.59%	0.046	0.045
Nov	2017	0.323	0.000	0.323	1.59%	0.046	0.118
Dec	2017	0.116	0.000	0.116	1.59%	0.046	0.042
						TOTAL	0.406

El Paso Natural Gas Company, LLC - Pecos River Compressor Station

Turbines

Units: **A-01, A-02, A-03**
Description: **GE Regenerative Cycle Turbines (model M3712R)**

ISO Rating:	**7150**	**hp**
Fuel Heating Value:	**1031**	**Btu/scf**
Heat Input Rate:	**56.45**	**MMBtu/hr**

	A-01	A-02	A-03
Hours:	5,323.25	3,813.75	5,031.50
Fuel Cons. (MMscf):	291.46	208.81	275.49

Criteria Pollutant	EF	Units	Source	A-01 TPY	A-02 TPY	A-03 TPY
NOx	9.7	lb/hr	Source Test (7/16/18)	25.924		
NOx	26.2	lb/hr	Source Test (7/23/18)		49.903	
NOx	22.1	lb/hr	Source Test (7/16/18)			55.497
CO	3.4	lb/hr	Source Test (7/16/18)	9.103		
CO	6.3	lb/hr	Source Test (7/23/18))		11.994	
CO	4.4	lb/hr	Source Test (7/16/18)			11.094
VOC	0.002	lb/MMBtu	AP-42	0.300	0.215	0.284
SO2	0.003	lb/MMBtu	AP-42	0.451	0.323	0.426
PM	0.007	lb/MMBtu	AP-42	1.052	0.753	0.994
HAP Pollutants						
Acetaldehyde	4.00E-05	lb/MMBtu	AP-42	0.006	0.004	0.006
Acrolein	6.40E-06	lb/MMBtu	AP-42	0.001	0.001	0.001
Benzene	1.20E-05	lb/MMBtu	AP-42	0.002	0.001	0.002
Ethylbenzene	3.20E-05	lb/MMBtu	AP-42	0.005	0.003	0.005
Formaldehyde	7.10E-04	lb/MMBtu	AP-42	0.107	0.076	0.101
Naphthalene	1.30E-06	lb/MMBtu	AP-42	0.000	0.000	0.000
PAH	2.20E-06	lb/MMBtu	AP-42	0.000	0.000	0.000
Propylene Oxide	2.90E-05	lb/MMBtu	AP-42	0.004	0.003	0.004
Toluene	1.30E-04	lb/MMBtu	AP-42	0.020	0.014	0.018
Xylene	6.40E-05	lb/MMBtu	AP-42	0.010	0.007	0.009
			Total HAPS	0.154	0.111	0.146

Month	Year	Blowdown Volumes (MMScf)	Additional Volume (ESDs, Other) (MMSCF)	Total Volume (MMSCF)	VOC %	Gas Density (lb/scf)	Monthly VOC (Tons)
Jan	2018	0.067	0.000	0.067	1.59%	0.046	0.024
Feb	2018	0.098	0.000	0.098	1.59%	0.046	0.036
Mar	2018	0.000	0.000	0.000	1.59%	0.046	0.000
Apr	2018	0.249	0.000	0.249	1.59%	0.046	0.091
May	2018	0.298	0.000	0.298	1.59%	0.046	0.109
Jun	2018	0.022	0.000	0.022	1.59%	0.046	0.008
July	2018	0.299	0.000	0.299	1.59%	0.046	0.109
Aug	2018	0.162	0.000	0.162	1.59%	0.046	0.059
Sep	2018	0.092	0.000	0.092	1.59%	0.046	0.034
Oct	2018	0.000	0.000	0.000	1.59%	0.046	0.000
Nov	2018	0.365	0.000	0.365	1.59%	0.046	0.133
Dec	2018	0.243	0.000	0.243	1.59%	0.046	0.089
						TOTAL	0.693

El Paso Natural Gas Company, LLC - Pecos River Compressor Station

Turbines

Units: A-01, A-02, A-03
Description: GE Regenerative Cycle Turbines (model M3712R)

ISO Rating:	**7150**	**hp**
Fuel Heating Value:	**1031**	**Btu/scf**
Heat Input Rate:	**56.45**	**MMBtu/hr**

	A-01	A-02	A-03
Hours:	4,982.50	7,165.50	6,501.75
Fuel Cons. (MMscf):	275.20	415.66	397.27

Criteria Pollutant	EF	Units	Source	A-01 TPY	A-02 TPY	A-03 TPY
NOx	20.6	lb/hr	Source Test (7/12/16)	51.394		
NOx	25.8	lb/hr	Source Test (6/21/16)		92.363	
NOx	26.8	lb/hr	Source Test (6/21/16)			87.188
CO	4.4	lb/hr	Source Test (7/12/16)	10.862		
CO	3.7	lb/hr	Source Test (6/21/16)		13.149	
CO	4.1	lb/hr	Source Test (6/21/16)			13.361
VOC	0.002	lb/MMBtu	AP-42	0.284	0.429	0.410
SO2	0.003	lb/MMBtu	AP-42	0.426	0.643	0.614
PM	0.007	lb/MMBtu	AP-42	0.993	1.500	1.434
HAP Pollutants						
Acetaldehyde	4.00E-05	lb/MMBtu	AP-42	0.006	0.009	0.008
Acrolein	6.40E-06	lb/MMBtu	AP-42	0.001	0.001	0.001
Benzene	1.20E-05	lb/MMBtu	AP-42	0.002	0.003	0.002
Ethylbenzene	3.20E-05	lb/MMBtu	AP-42	0.005	0.007	0.007
Formaldehyde	7.10E-04	lb/MMBtu	AP-42	0.101	0.152	0.145
Naphthalene	1.30E-06	lb/MMBtu	AP-42	0.000	0.000	0.000
PAH	2.20E-06	lb/MMBtu	AP-42	0.000	0.000	0.000
Propylene Oxide	2.90E-05	lb/MMBtu	AP-42	0.004	0.006	0.006
Toluene	1.30E-04	lb/MMBtu	AP-42	0.018	0.028	0.027
Xylene	6.40E-05	lb/MMBtu	AP-42	0.009	0.014	0.013
			Total HAPS	0.146	0.220	0.210

Month	Year	Blowdown Volumes (MMScf)	Additional Volume (ESDs, Other) (MMSCF)	Total Volume (MMSCF)	VOC %	Gas Density (lb/scf)	Monthly VOC (Tons)
Jan	2016	0.133	0.185	0.318	1.59%	0.046	0.116
Feb	2016	0.038	0.042	0.080	1.59%	0.046	0.029
Mar	2016	0.165	0.315	0.480	1.59%	0.046	0.176
Apr	2016	0.255	0.362	0.617	1.59%	0.046	0.226
May	2016	0.086	0.247	0.333	1.59%	0.046	0.122
Jun	2016	0.297	1.108	1.405	1.59%	0.046	0.514
July	2016	0.160	2.195	2.355	1.59%	0.046	0.861
Aug	2016	0.235	0.994	1.229	1.59%	0.046	0.449
Sep	2016	0.210	0.312	0.522	1.59%	0.046	0.191
Oct	2016	0.293	0.275	0.568	1.59%	0.046	0.208
Nov	2016	0.072	0.118	0.190	1.59%	0.046	0.069
Dec	2016	0.440	0.339	0.779	1.59%	0.046	0.285
						TOTAL	3.246

From:	Nolting, Leslie R
To:	Baca, Michael, NMENV; Mehdizadeh, Fariba
Cc:	Butt, Neal, NMENV; Jones, Mark, NMENV
Subject:	[EXT] RE: Regional Haze Four-Factor Analyses Follow Up
Date:	Tuesday, February 23, 2021 5:40:55 PM
Attachments:	EPNG Interest Rate documentation.pdf

Hi Michael,

Our responses to the most recent questions are below:

Company Specific Interest Rate:

Please see attached documentation ("EPNG Interest Rate documentation.pdf") signed by our Chief Financial Officer in support of the 8.53% cost of debt rate. Please note also our request to treat the supporting document with the background of the calculation as Confidential Business Information. Publicly-available support for the cost-of-debt rate is provided as a link in the attached document.

Operation and Maintenance (O&M) Costs:

We believe that in general the O&M costs reflect incremental costs, over and above existing O&M costs. However, the electricity vs fuel costs for Electric Motor Drive (EMD) replacements are the exception to this statement. For the replacement of gas-driven compression with EMD, we believe our +/- 25% estimate did not reflect the cost of fuel savings.

We estimate that the cost of fuel *based on calendar year 2016 operation* for each facility was approximately:

Washington Ranch: $375,000
Pecos River: $2,720,000
Blanco A: $615,000

Thank you again for your patience and assistance. Please let me know if there is anything further we can provide.

Leslie Nolting | Manager | Air Permitting and Compliance
KINDER MORGAN | Natural Gas Pipelines
2 North Nevada Avenue | Colorado Springs, CO 80903
Office: 719-520-4652 **|Cell:** 719-355-9416
Leslie_Nolting@kindermorgan.com

KINDER MORGAN

Delivering Energy to Improve Lives

February 23, 2020

Mr. Michael Baca
Control Strategies Manager
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

El Paso Natural Gas Company, L.L.C. (EPNG)
Company-Specific Interest Rate Utilized in Regional Haze Four-Factor Analyses

Dear Mr. Baca:

The attached sheet, entitled "El Paso Natural Gas Company, L.L.C., Debt Capital, For the Twelve Months Ending December 31, 2019, as adjusted" shows a weighted average cost of debt of 8.53%. This weighted average cost of debt will be published in EPNG's Federal Energy Regulatory Commission (FERC) Form 2 filing for the year ended 2020 and will be publicly available. However, we do not expect this to be published until April 2021, and therefore this information should be treated as confidential business information, not subject to public review under N.M. Stat. Ann § 14-2-1 (H).

The most recent publicly available EPNG Form 2 filing for calendar year 2019 shows a cost of debt of 8.55%, which is based on EPNG's year-ended 2018 capital structure. This filing can be found at https://elibrary.ferc.gov/eLibrary/search by entering "4/29/2020" for the date range and entering "El Paso Natural Gas Form 2" in the Keyword Search field. The relevant data are located on pages 218a and pages 256-260 of the document. The methodology used to calculate this 8.55% cost of debt for the year ended 2018 is consistent with that used to calculate the 8.53% cost of debt for the year ended 2019 included in the attached sheet.

Sincerely,

David P. Michels
Chief Financial Officer

CBI Attachment Omitted

From:	Mitchell, Tom
To:	Olson, Kirby, ENV
Cc:	Baca, Michael, ENV; Jones, Mark, ENV; Daly, Weiwen; Duarte, Ricardo (Richard)
Subject:	RE: [EXTERNAL] RE: agenda for meeting on 5/3 with AQB
Date:	Friday, May 26, 2023 2:15:40 PM
Attachments:	image001.png Cooper_Parts_Letter_52323.pdf

Ms. Olson:

Ms. Olson:

During our recent meeting, you and your staff asked 3 questions that we said we would get back to you about. Specifically:

- Operation and Maintenance Costs
  - Availability of maintenance parts for the engines and combustion turbines for 10 to 20 years
  - Estimates of maintenance costs for units
- Replacement - Costs for the replacement of the existing reciprocating internal combustion engines (RICE)/combustion turbines (CT) with new RICE/CT.
- Electrification - basis of the cost estimate ($/mile) for installing medium voltage electric utility distribution lines.

We are pleased to provide the following responses:

Operation and Maintenance Costs

Ongoing Operations

Cooper, the Original Equipment Manufacturer (OEM) for RICE at the stations in question, has stated that they have no plans to discontinue support of the installed engines. Please see the attached letter. Cooper has further stated they have millions of dollars of parts in stock to support these model engines as well as the many others that they have manufactured over the years, and they continue to place new orders for parts. Finally, it should be noted that the oldest engines in our fleet manufactured by Cooper were designed and installed in the early 1940s and are still operating. This demonstrates that the slow speed engines are very robust and that, when properly maintained, will operate for the foreseeable future.

KM's fleet of GE turbines is much the same. Additionally, there is a significant fleet of Frame 3 turbines operating throughout the world that GE has indicated they intend to continue to support.

Maintenance Costs

Regarding maintenance costs units, the slow speed engines require very little ongoing planned maintenance beyond consumables (e.g., oil changes, spark plugs, belts hoses etc.) due to the durability of the engines between routine overhauls. Similarly, the GE turbines also require little planned maintenance between routine overhauls. Routine overhauls are periodically required based on operating hours and currently cost approximately $750K each for the RICE and between $1.5 MM - $2 MM each for the CTs. Our budgeted planned maintenance costs for the entire fleet (25 units total including CTs and RICE units) at the 3 stations for 2023 is less than $200K with no overhauls planned in this calendar year.

Replacement Costs

As discussed during our meeting, KM believes that requiring replacement of existing equipment is beyond the scope of the Regional Haze rule. The Clean Air Act, 42 USC Section 7491(g)(2) and elsewhere uses the term "best available retrofit technology." The term "retrofit" denotes modifications to existing equipment and not replacement of equipment. EPA itself acknowledged this in Appendix Y to 40 CFR Part 51 entitled "Guidelines for BART Determinations Under the Regional Haze Rule" which stated in part as follows:

1. Step 1: How do I identify all available retrofit emission control techniques?
    1. Available retrofit control options are those air pollution control technologies with a practical potential for application to the emissions unit and the regulated pollutant under evaluation…

(40 CFR Appendix Y, IV.D.1)

Thus the CAA's use of "best available retrofit technology" has as its central requirement that it be applied to existing equipment, rather than being replaced with totally new equipment. Additionally, even if replacement of units was within the scope of the rule – which it is not –, replacement costs would be economically infeasible. In the interest of providing general background information on the subject, KM has found that replacement cost for RICE or CTs compressor drivers are generally consistent across both drive types. Costs, as measured in $/hp, vary according to size installed, with lower HP installations generally costing more. For project scoping, KM generally uses a rule of thumb of $3,200/hp for greater than 15,000 hp installed and $4,200 for less than 15,000 hp installed based on a number of recent detailed project estimates.

Electrification

Even if replacement of units was within the scope of the rule – which it is not –, mandating the use of EMDs would be economically infeasible. In addition to the cost of the EMD itself, electrification generally requires additional electrical lines and substations. Based on current estimating practices for projects, KM uses between $500k-$1MM per mile of overhead electrical line and, depending on total horsepower being electrified, approximately another $5MM for a substation.

Note that in response to questions from our original 2019 submittal, KM cited a cost of $500K/mile for overhead electrical lines. We expect that current costs per mile would be higher – more towards the middle of the above cited $500k-$1MM per mile. However, for Blanco, the nearest high voltage line is underground. To estimate the Blanco costs, we used a cost estimate for a then current project that had underground utilities and scaled to the distance needed for Blanco.

If you have any questions on the above response, please contact Weiwen, Richard or myself. Thank you and we look forward to working with you and your team.

R. Thomas Mitchell
EHS Manager, Air Permitting and Compliance
Office: 713.420.3463
Cell: 713.907.0797

KINDER MORGAN

Delivering Energy to Improve Lives

COOPER | MACHINERY SERVICES

May 23, 2023

Mr. James Trent
Staff Engineer
Kinder Morgan
1001 Louisiana Street
Houston, TX 77002

Dear James,

Cooper Machinery Services was founded in 1833, and for much of its existence has been focused on designing, producing, and servicing natural gas engines and compressors.

The production of new spare parts and emissions upgrades are the core of our current business model and will continue to be so for the foreseeable future.

Thus, I would like to confirm that Cooper Machinery Services has no plans to stop producing new parts for Cooper equipment, and will continue to service your GMV-10TF, GMW-10, 6V-250 and 12Q155HC2 models for as long as our company exists.

If you have any questions or need more details on Cooper's parts offering, please feel free to contact me.

Sincerely,



Patrick Gillespie
Vice President of Sales - Americas
(832) 316-9506
patrick.gillespie@cooperservices.com

D.4 Enterprise Field Services

Supporting documentation for Enterprise Field Services is provided below. Facility-specific documentation is provided first, followed by documentation pertaining to multiple facilities and/or the owner/operator. The following documents are included in this section (in reading order):

- Blanco C&D Compressor Station:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (11/14/2019)
    - Follow-Up Submittal (2/14/2020)
    - Follow-Up Submittal (2/26/2020)
    - Follow-Up Submittal (5/19/2020)
    - Follow-Up Submittal (6/2/2020)
    - Follow-Up Submittal (10/1/2020)
- Chaco Gas Plant:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (11/14/2019)
    - Follow-Up Submittal (2/24/2020)
    - Follow-Up Submittal (10/1/2020)
- South Carlsbad Compressor Station:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (10/30/2019)
    - Follow-Up Submittal (2/13/2020)
    - Follow-Up Submittal (2/26/2020)
    - Follow-Up Submittal (3/17/2020)
    - Follow-Up Submittal (10/1/2020)
- Multiple Facilities and/or Owner/Operator:
    - Follow-Up Submittal (9/8/2020)
    - Follow-Up Submittal (3/4/2021)
    - Follow-Up Submittal (8/30/2023)

NMED Final Cost Evaluation
Enterprise Field Services - Blanco C&D Compressor Station

Facility Information

Enterprise - Blanco C & D	**Facility**
Two pre-June 1989 CTs, 22,280 HP each	**Units**
T-C01 and T-C02	**Unit IDs**
Water/Steam Injection	**Evaluated Pollution Control**
42.0	**Post-control Emissions Rate (ppmvd)***

*Source (A), Table S-1

Supporting Information

1999	**Calendar year associated with cost estimates (based on primary data source)***
22,280	**Nameplate Capacity (hp/unit)**

*Source (A), Table A-4

Economic Evaluation

Cost Component		T-C01	T-C02	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 431,000	$ 431,000	(A)	Total system cost
Other Direct Capital Costs 1 ($)	ODC	$ 243,975	$ 243,975	(A)	Taxes Freight and installation direct costs
Indirect Capital Costs ($)	IDC	$ 408,200	$ 408,200	(A)	Indirect installation and contingency
Total Capital Costs - Direct ($)	TCC	$ 1,083,175	$ 1,083,175	-	PEC + ODC + IDC
Additional Capital ($)	AC	$ -	$ -	-	Not specified by Enterprise
Total Capital Investment ($)	TCI	$ 1,083,175	$ 1,083,175	(A)	TCC + AC
Interest Rate (%)	R	10.50%	10.50%	Enterprise August 2023 FFA update	
Useful Life (yr)	Y	15	15	Enterprise initial (2019) FFA and August 2023 update	
Capital Recovery Factor	CRF	0.1352	0.1352	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 146,497	$ 146,497	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 294,000	$ 294,000	(A)	Annual costs (does not include Capital Recovery)
Other Indirect Annual Costs ($/yr)	OAC	$ 43,327	$ 43,327	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 483,824	$ 483,824	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	30%	40%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	278.9	288.0	CY 2019 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	278.9	288.0	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	84.8	114.5	-	PAE x Eff
1999$ Cost Effectiveness ($/ton)	**CE1**	**$ 5,706**	**$ 4,227**	-	TAC/ER
Price Index	PI	2.04	2.04	-	CEPCI 2024* / CEPCI 1999 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 11,640**	**$ 8,622**	-	CE1 x PI

(A) Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, Nov 1999, Table A-4, 25 MW Class
Note: Units T-C01 and T-C02 are ~ 16.6 MW (mechanical) units and thus reasonably similiar in size to the 25 MW Class used in the analysis.

NMED Final Cost Evaluation
Enterprise Field Services - Blanco C&D Compressor Station

Facility Information

Enterprise - Blanco C & D	**Facility**
Two pre-June 1989 CTs, 22,280 HP each	**Units**
T-C01 and T-C02	**Unit IDs**
SCR	**Evaluated Pollution Control**

Supporting Information

2024	**Calendar year associated with cost estimates**
189.1	**Heat Input Capacity (MMBtu/hr/unit, calculated)**

Economic Evaluation

Cost Component		Unit T-C01	Unit T-C02	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	A retrofit factor of 1.1 was used in the EPA SCR Tool to account for the additional capital costs anticipated to create physical space for the SCR system. This factor was selected based on Enterprise's recurring assertion that the current layout of the existing building can not accommodate the physical space needed for SCR. Aerial photos provided by Enterprise suggest there is space for SCR if building modifications are made.
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ 8,436,472	$ 8,436,472	EPA SCR Tool (2024$)	
Additional Capital ($)	AC	$ -	$ -	See Note	
Total Capital Investment ($)	TCI	$ 8,436,472	$ 8,436,472	-	TCC + AC
Interest Rate (%)	R	10.50%	10.50%	Enterprise August 2023 FFA update	
Useful Life (yr)	Y	20	20	Default per EPA Cost Manual	
Capital Recovery Factor	CRF	0.1215	0.1215	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 1,024,975	$ 1,024,975	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 199,269	$ 201,863	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 3,134	$ 3,134	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 1,227,378	$ 1,229,972	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	80%	80%	EPA SCR Tool	Consistent with EPA and industry documentation
Baseline Actual NOx Emissions (ton/yr)	BAE	278.9	288.0	CY 2019 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	278.9	288.0	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	223.1	230.4	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 5,502**	**$ 5,338**	-	TAC/ER

NMED Final Cost Evaluation
Enterprise Field Services - Blanco C&D Compressor Station

Facility Information

Enterprise - Blanco C & D	**Facility**
Two pre-June 1989 CTs, 22,280 HP each	**Units**
T-C01 and T-C02	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
9.0	**Post-control Emissions Rate (ppmvd)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired CT >15,900 hp

Supporting Information

2020	**Calendar year associated with cost estimates (year not specified in submission)**
22,280	**Nameplate Capacity (hp/unit)**

Economic Evaluation

Cost Component		T-C01	T-C02	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 53,873,040	$ 53,873,040	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $2418/hp cost metric as Enterprise did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered CT.
Interest Rate (%)	R	10.50%	10.50%	Enterprise August 2023 FFA update	
Useful Life (yr)	Y	30	30	ERG experience based on discussions with CT manufacturers	
Capital Recovery Factor	CRF	0.1105	0.1105	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 5,954,505	$ 5,954,505	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 40,917	$ 40,917	Enterprise August 2023 FFA update (2024$ converted to 2020$ using CEPCI)	Incremental overhaul costs for DLN retrofit
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 5,995,422	$ 5,995,422	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	85%	87%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	278.9	288.0	CY 2019 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	278.9	288.0	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	237.3	250.8	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 25,268**	**$ 23,901**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 so assumed costs are in 2020$
Price Index	PI	1.34	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 33,859**	**$ 32,028**	-	CE1 x PI

NMED Final Cost Evaluation
Enterprise Field Services - Blanco C&D Compressor Station

Facility Information

Enterprise - Blanco C & D	**Facility**
Two pre-June 1989 CTs, 22,280 HP each	**Units**
T-C01 and T-C02	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (lb/hr)**

Additional Information

2023	**Calendar year associated with cost estimates**
22,280	**Nameplate Capacity (hp/unit)**

Economic Evaluation

Cost Component		T-C01	T-C02	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Enterprise provided a cost estimate for electrification using EPA Cost Control Manual Section 5.2, which pertains to acid gas scrubbers. As this is not applicable to replacement with EMD, a Total Capital Cost metric of $2,084 (2023$/hp) was calculated using detailed cost information provided by other facilities. The TCI figure assumes no costs associated with substation or distribution line upgrades. This assumption underestimates costs given that Enterprise indicated in its August 2023 update that utility infrastructure upgrades would be needed to support electrification at all three of its facilities.
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ 46,431,520	$ 46,431,520	See Note	
Additional Capital ($)	AC	$ -	$ -	-	
Total Capital Investment ($)	TCI	$ 46,431,520	$ 46,431,520	See Note	TCC + AC
Interest Rate (%)	R	10.50%	10.50%	Enterprise Aug 2023 FFA update	
Useful Life (yr)	Y	25	25	Consistent with other FFAs	
Capital Recovery Factor	CRF	0.114	0.114	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 5,313,127	$ 5,313,127	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 4,485,294	$ 4,538,198		AED + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 8,970,588	$ 9,076,396	ERG calculation	Assumes units at 60% load, 95% efficiency and a $0.10/kWh price
Associated non-electricity O&M ($/yr)	AOM	$ -	$ -	Engineering judgement	Assumed to be negligible
Annual Fuel Credit ($/yr)	AFC	$ (4,485,294)	$ (4,538,198)	ERG calculation	Assumed equal to 50% of AED
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 9,798,421	$ 9,851,325	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	100%	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	278.9	288.0	CY 2019 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	278.9	288.0	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	278.9	288.0	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 35,137**	**$ 34,202**	-	TAC/ER
Price Index	PI	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 35,137**	**$ 34,202**	-	CE1 x PI

NMED Final Cost Evaluation
Enterprise Field Services - Blanco C&D Compressor Station

Facility Information

Enterprise - Blanco C & D	**Facility**
Pre-October 1987 GE M5322B NG CT, 32,550 HP	**Units**
T-D01	**Unit IDs**
DLN	**Evaluated Pollution Control**
35.0	**Post-control Emissions Rate (ppmvd)***

*From Enterprise August 2023 FFA update. Vendor stated 25 ppm may be possible "depending on CO requirements and detailed evaluation."

Supporting Information

2023	**Calendar year associated with cost estimates (year not specified in submission)**
32,550	**Nameplate Capacity (hp/unit)**

Economic Evaluation

Cost Component		T-D01	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 5,000,000	Enterprise August 2023 FFA Update	
Interest Rate (%)	R	10.50%	Enterprise August 2023 FFA Update	
Useful Life (yr)	Y	20	Enterprise initial (2019) FFA and August 2023 update	Consistent with other FFAs
Capital Recovery Factor	CRF	0.1215	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 607,466	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 54,829	Enterprise August 2023 FFA Update	"Incremental overhaul costs"
Other Indirect Annual Costs ($/yr)	OAC	$ 200,000	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 862,295	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	55%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	515.7	CY 2022 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	515.7	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	282.3	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 3,055**	-	TAC/ER
Price Index	PI	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 3,055**	-	CE1 x PI

NMED Final Cost Evaluation
Enterprise Field Services - Blanco C&D Compressor Station

Facility Information

Enterprise - Blanco C & D	**Facility**
Pre-October 1987 GE M5322B NG CT, 32,550 HP	**Units**
T-D01	**Unit IDs**
Water/Steam Injection	**Evaluated Pollution Control**
42.0	**Post-control Emissions Rate (ppmvd)**

*Source (A), Table S-1

Supporting Information

1999	**Calendar year associated with cost estimates (based on primary data source)**
32,550	**Nameplate Capacity (hp/unit)**

*Source (A), Table A-4

Economic Evaluation

Cost Component		T-D01	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 431,000	(A)	Total system cost
Other Direct Capital Costs 1 ($)	ODC	$ 243,975	(A)	Taxes Freight and installation direct costs
Indirect Capital Costs ($)	IDC	$ 408,200	(A)	Indirect installation and contingency
Total Capital Costs - Direct ($)	TCC	$ 1,083,175	-	PEC + ODC + IDC
Additional Capital ($)	AC	$ -	-	Not specified by Enterprise
Total Capital Investment ($)	TCI	$ 1,083,175	(A)	TCC + AC
Interest Rate (%)	R	10.50%	Enterprise August 2023 FFA update	
Useful Life (yr)	Y	15	Enterprise initial (2019) FFA and August 2023 update	
Capital Recovery Factor	CRF	0.1352	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 146,497	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 294,000	(A)	Annual costs (does not include Capital Recovery)
Other Indirect Annual Costs ($/yr)	OAC	$ 43,327	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 483,824	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	46%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	515.7	CY 2022 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	515.7	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	235.6	-	PAE x Eff
1999$ Cost Effectiveness ($/ton)	**CE1**	**$ 2,054**	-	TAC/ER
Price Index	PI	2.04	-	CEPCI 2024* / CEPCI 1999 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 4,190**	-	CE1 x PI

(A) Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, Nov 1999, Table A-4, 25 MW Class
Note: Unit T-D01 is ~ 24 MW (mechanical) and thus reasonably similiar in size to the 25 MW Class used in the analysis.

NMED Final Cost Evaluation
Enterprise Field Services - Blanco C&D Compressor Station

Facility Information

Enterprise - Blanco C & D	**Facility**
One pre-October 1987 GE M5322B NG CT, 32,550 HP	**Units**
T-D01	**Unit IDs**
SCR	**Evaluated Pollution Control**

Supporting Information

2024	**Calendar year associated with cost estimates**
311.2	**Heat Input Capacity (MMBtu/hr/unit, calculated)**

Economic Evaluation

Cost Component		Unit T-D01	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	A retrofit factor of 1.1 was used in the EPA SCR Tool to account for the additional capital costs anticipated to create physical space for the SCR system. This factor was selected based on Enterprise's recurring assertion that the current layout of the existing building can not accommodate the physical space needed for SCR. Aerial photos provided by Enterprise suggest there is space for SCR if building modifications are made.
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ 11,662,378	EPA SCR Tool (2024$)	
Additional Capital ($)	AC	$ -	See Note	
Total Capital Investment ($)	TCI	$ 11,662,378	-	TCC + AC
Interest Rate (%)	R	10.50%	Enterprise August 2023 FFA update	
Useful Life (yr)	Y	20	Default per EPA Cost Manual	
Capital Recovery Factor	CRF	0.1215	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 1,416,900	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 325,376	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 3,328	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 1,745,604	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	80%	EPA SCR Tool	Consistent with EPA and industry documentation
Baseline Actual NOx Emissions (ton/yr)	BAE	515.7	CY 2022 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	515.7	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	412.6	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 4,231**	-	TAC/ER

NMED Final Cost Evaluation
Enterprise Field Services - Blanco C&D Compressor Station

Facility Information

Enterprise - Blanco C & D	**Facility**
Pre-October 1987 GE M5322B NG CT, 32,550 HP	**Units**
T-D01	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
9.0	**Post-control Emissions Rate (ppmvd)**

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired CT >15,900 hp

Supporting Information

2020	**Calendar year associated with cost estimates (year not specified in submission)**
32,550	**Nameplate Capacity (hp/unit)**

Economic Evaluation

Cost Component		T-D01	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 78,705,900	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $2418/hp cost metric as Enterprise did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered CT.
Interest Rate (%)	R	10.50%	Enterprise August 2023 FFA update	
Useful Life (yr)	Y	30	ERG experience based on discussions with CT manufacturers	
Capital Recovery Factor	CRF	0.1105	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 8,699,244	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 40,917	Enterprise August 2023 FFA update (2024$ converted to 2020$ using CEPCI)	Incremental overhaul costs for DLN retrofit
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 8,740,161	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	88%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	515.7	CY 2022 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	515.736	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	455.7	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 19,180**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 so assumed costs are in 2020$
Price Index	PI	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 25,701**	-	CE1 x PI

NMED Final Cost Evaluation
Enterprise Field Services - Blanco C&D Compressor Station

Facility Information

Enterprise - Blanco C & D	**Facility**
Pre-October 1987 GE M5322B NG CT, 32,550 HP	**Units**
T-D01	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (lb/hr)**

Additional Information

2023	**Calendar year associated with cost estimates**
32,550	**Nameplate Capacity (hp/unit)**

Economic Evaluation

Cost Component		T-D01	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	Enterprise provided a cost estimate for electrification using EPA Cost Control Manual Section 5.2, which pertains to acid gas scrubbers. As this is not applicable to replacement with EMD, a Total Capital Cost metric of $2,084 (2023$/hp) was calculated using detailed cost information provided by other facilities. The TCI figure assumes no costs associated with substation or distribution line upgrades. This assumption underestimates costs given that Enterprise indicated in its August 2023 update that utility infrastructure upgrades would be needed to support electrification at all three of its facilities.
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ 67,834,200	See Note	
Additional Capital ($)	AC	$ -	-	
Total Capital Investment ($)	TCI	$ 67,834,200	See Note	TCC + AC
Interest Rate (%)	R	10.50%	Enterprise Aug 2023 FFA update	
Useful Life (yr)	Y	25	Consistent with other FFAs	
Capital Recovery Factor	CRF	0.114	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 7,762,221	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 6,552,797		AED + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 13,105,594	ERG calculation	Assumes unit at 60% load, 95% efficiency and a $0.10/kWh price
Associated non-electricity O&M ($/yr)	AOM	$ -	Engineering judgement	Assumed to be negligible
Annual Fuel Credit ($/yr)	AFC	$ (6,552,797)	ERG calculation	Assumed equal to 50% of AED
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 14,315,018	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	515.7	CY 2022 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	515.7	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	515.7	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 27,756**	-	TAC/ER
Price Index	PI	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 27,756**	-	CE1 x PI

NMED Final Cost Evaluation
Enterprise Field Services - Blanco C&D Compressor Station

Unit T-C01: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.1

* NOTE: You must document why a retrofit factor of 1.1 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	189.1	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	1,568,007,662	scf/Year
	8549	hr/yr
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5605	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.3448	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0690	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	10.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit T-C01: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	189	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,606,708,050	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,568,007,662	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.976	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8549	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	52.16	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	222.96	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.10		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3007	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	749.34	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	20	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	70	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	9	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	3,200	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.1215

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	111.95	kW

Unit T-C01: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$8,436,472	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$199,269	in 2024 dollars
Indirect Annual Costs (IDAC) =	$1,028,166	in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$1,227,434	in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$42,182	in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$42,228	in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$95,705	in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$19,153	in 2024 dollars
Direct Annual Cost =		$199,269	in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,134	in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,025,031	in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,028,166	in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,227,434	per year in 2024 dollars
NOx Removed =	223	tons/year
Cost Effectiveness =	$5,505	per ton of NOx removed in 2024 dollars

NMED Final Cost Evaluation
Enterprise Field Services - Blanco C&D Compressor Station

Unit T-C02: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.1

* NOTE: You must document why a retrofit factor of 1.1 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	189.1	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	1,586,532,493	scf/Year
	8650	hr/yr
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 5605 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.3522	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0704	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024			
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI
Annual Interest Rate (i)	10.5	Percent		
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia		
Electricity ($Cost_{elect}$)	0.1000	$/kWh		
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	60.00	$/hour (including benefits)*		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

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Unit T-C02: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	189	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,606,708,050	scf/Year
Actual Annual fuel consumption (Mactual) =		1,586,532,493	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.987	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8650	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	53.28	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	230.44	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.10	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3007	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	751.19	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole
Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	21	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	71	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	10	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	3,300	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.1215

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	111.95	kW

Unit T-C02: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$8,436,472	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$201,863 in 2024 dollars
Indirect Annual Costs (IDAC) =	$1,028,166 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$1,230,029 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$42,182 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$43,645 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$96,836 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$19,200 in 2024 dollars
Direct Annual Cost =		$201,863 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,134 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,025,031 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,028,166 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,230,029 per year in 2024 dollars
NOx Removed =	230 tons/year
Cost Effectiveness =	$5,338 per ton of NOx removed in 2024 dollars

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Unit T-D01: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.1

* NOTE: You must document why a retrofit factor of 1.1 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	311.2	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	2,571,097,575	scf/Year
	8518	hr/yr
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5605	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.3891	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0778	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	10.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit T-D01: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	311	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	2,644,143,550	scf/Year	
Actual Annual fuel consumption (Mactual) =		2,571,097,575	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.972	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8518	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	96.88	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	412.61	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.10		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3007	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	1,251.40	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	38	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	130	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	17	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	5,900	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.1215

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	184.23	kW

Unit T-D01: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$11,662,378	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$325,376	in 2024 dollars
Indirect Annual Costs (IDAC) =	$1,420,307	in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$1,745,683	in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$58,312	in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$78,149	in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$156,930	in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$31,985	in 2024 dollars
Direct Annual Cost =		$325,376	in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,328	in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,416,979	in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,420,307	in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,745,683	per year in 2024 dollars
NOx Removed =	413	tons/year
Cost Effectiveness =	$4,231	per ton of NOx removed in 2024 dollars

Enterprise Products

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS HOLDINGS LLC
(General Partner)

ENTERPRISE PRODUCTS OPERATING LLC

November 14, 2019

Federal Express

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

Re: Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program
Enterprise Field Services, LLC
Blanco C&D Compressor Station and Chaco Gas Plant

Mr. Singleton:

Enterprise Field Services, LLC is submitting an analysis of control measures for the Blanco C&D Compressor Station and the Chaco Gas Plant in San Juan County, New Mexico, as requested by the NMED by letter dated July 18, 2019 and extended by the NMED letter dated October 29, 2019.

In addition, Enterprise has included legal comments, which are integral to Enterprise's position on the appropriateness of the control measures analyzed for all three facilities. For convenience and to avoid duplication, the legal comments are for the South Carlsbad Compressor Station, Blanco C&D Compressor Station and the Chaco Gas Plant.

If you have questions or require additional information, please contact me at (713) 381-6698 or by email at rmhavalda@eprod.com or Bradley Cooley at (713) 381-5828.

Thank you,

Robert Havalda, P.E.
Senior Engineer, Environmental

Bradley J. Cooley, P.E.
Senior Manager, Environmental

/kna
Attachment

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Michelle Lujan Grisham
Governor

Howie C. Morales
Lt. Governor

James C. Kenney
Cabinet Secretary

Jennifer J. Pruett
Deputy Secretary

October 29, 2019

Robert Havalda, P.E.
Senior Engineer, Environmental
Enterprise Products Partners, L.P.
P.O. Box 4324
Houston, TX 77210-4324

Re: Request for Two-Week Extension for Submittal of the Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program
Enterprise Products Partners, L.P.

Mr. Havalda:

The New Mexico Environment Department Air Quality Bureau (AQB) has received and reviewed your written request to extend the submittal deadline for the Blanco C & D Compressor Station and Chaco Gas Plant four-factor analyses from November 1, 2019 to November 15, 2019.

This letter grants the requested extension. Should you have any additional questions or concerns as these reports are finalized, please do not hesitate to contact Mark Jones at 505.566.9746 (mark.jones@state.nm.us) or me at 505.476.4350 (kerwin.singleton@state.nm.us).

Sincerely,

Kerwin C. Singleton
Planning Section Chief

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NOV 06 2019
ENVIRONMENTAL DEPARTMENT

REGIONAL HAZE FOUR-FACTOR ANALYSIS

Enterprise Field Services, LLC, Blanco C & D Compressor Station

Prepared By:

Adam Erenstein – Manager of Consulting Services
Jake Zenker - Consultant

TRINITY CONSULTANTS
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November 2019

Project 193201.0181

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1. EXECUTIVE SUMMARY

In the 1977 amendments to the Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977. EPA has since amended the RHR in certain respects, most recently on January 10, 2017.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, the states, among other things:

(A) "[E]valuate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment" and "include in [the state's] implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy." 40 CFR 51. 308(f)(2)(i). This is known as a four-factor analysis.

(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the state must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the state must consider the uniform rate of improvement in visibility. 40 CFR 51. 308(f)(1). The uniform rate of progress or improvement is sometimes referred to as the "URP" or the glidepath and is considered in the process of developing the state's Long Term Strategy (LTS).

The second implementation, or planning, period (2019-2028) for national regional haze efforts is currently underway. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural or biogenic and manmade or anthropogenic sources of emissions. Using a Photochemical Grid Model (PGM), the Western Regional Air Partnership (WRAP), in coordination with the EPA, is tasked with comparing anthropogenic source contributions against natural background concentrations. EPA has issued guidance to states for development of State Implementation Plans (SIPs) for regional haze requirements for the second planning period.[1,2]

[1] U.S. EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, EPA-457/B-19-003 (Aug. 2019); U.S. EPA, Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program, EPA-454/R-18-010 (Dec. 2018).

[2] U.S. EPA, Technical Support Document for EPA's 2028 Regional Haze Modeling (Sept. 2019).

Pursuant to 40 CFR 51.308(f)(2), the states are responsible for identifying sources that contribute to the most impaired days in the Class I areas. To accomplish this, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for Title V sources and screened each facility's potential impact on visibility in Class I areas using a "Q/d" analysis, where "Q" is the magnitude of emissions that could impact ambient visibility and "d" is the distance of a facility to a Class I area. The NMED defined a source with a high potential for visibility impairment as one with a "Q/d" greater than 5.5. From this analysis, 24 facilities were identified by the NMED. On July 18, 2019, the NMED informed Enterprise Field Services, LLC (Enterprise) that its facility, the Blanco C&D Compressor Station (Blanco), was identified as one of the sources potentially contributing to regional haze at the Mesa Verde Class I area.

In coordination with guidance provided by WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. The NMED's July 18, 2019 notification letter to Enterprise specifies that any equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The equipment at the facility that is subject to this analysis, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant are reported in Table 1.

Table 1. Summary of Equipment and Applicability to a Four-Factor Analysis

Equipment	Unit No.	NO_X Hourly PTE (lb/hr)	NO_X Annual PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
GE 5221W Turbines	T-CO1	80.0	350.4	Yes	< 1.0	1.1	No
	T-CO2	80.0	350.4	Yes	< 1.0	1.1	No
GE M5322B Turbine	T-DO1	143.3	628.0	Yes	< 1.0	1.4	No

Once the applicability of process equipment and pollutants has been determined, potential retrofit control technologies must be identified. One of the reference sources that the NMED has suggested consulting is the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC).[3] In order to determine the most relevant and current retrofit controls available, the RBLC was queried for the previous ten years. Summaries of the results of this search are provided and discussed in Section 2 of this report. The facility engineers then reviewed the list of available retrofit technologies and performed a technical feasibility assessment for each control option. The four-factor analysis was then conducted for those controls that are technically feasible at the Blanco site.

Based on the technical and economic factors summarized in this report, Enterprise has provided recommendations for the NMED in its efforts to design, in coordination with WRAP, the SIP under the RHR.

[3] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

2.1. COMBUSTION TURBINES

Three of Blanco's natural gas-fired turbines (Units T-CO1, T-CO2, and T-DO1) are subject to this four-factor analysis due to their NO_X emission rates. The only pollutant subject to evaluation for these units is NO_X.

2.1.1. Combustion Turbine Background

A gas turbine is an internal combustion engine that operates with a rotary, rather than reciprocating, motion and is composed of three primary components: a compressor, a combustor, and a power turbine. The compressor draws in ambient air and compresses it up to 30 times the ambient pressure, then directs it into the combustor, where fuel is introduced, ignited, and burned. Exhaust gas from the combustor is then diluted with additional air and sent to the power turbine at temperatures of up to 2600 °F. The hot exhaust gas expands in the power turbine section, generating energy in the form of shaft horsepower.[4]

The treatment of the exhaust gases exiting the turbine dictates the cycle designation of these units. The heat content can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).[5] The units at Blanco are regenerative cycle turbines, which are essentially simple cycle gas turbines with an added heat exchanger.

NO_x is formed via three fundamentally different mechanisms. The principal NO_x formation mechanism, thermal NO_x, arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion. Most thermal NO_x forms in the highest temperature regions of the combustion chamber. The second NO_x formation mechanism, fuel NO_x, arises from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. The final NO_x formation mechanism, prompt NO_x, arises from early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The significance of prompt NO_x is negligible in comparison to thermal and fuel NO_x. Fuel NO_x will also be negligible for Blanco's turbines assessed here, as these combustion turbines fire natural gas, which contains a negligible amount of nitrogen compounds. Therefore, this analysis will focus on thermal NO_x.

The PTE from each turbine is reported in the facility's New Source Review (0613-M11) and Title V (218-R2) permits and is summarized in Table 1.

2.1.2. Potential NO_X Controls for a Combustion Turbine

There are three general methods of controlling NO_X emissions from gas turbines: (1) wet controls, which use steam or water injection to reduce combustion temperatures and NO_X formation, (2) dry controls that use

[4] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines."

[5] Ibid.

advanced combustor design to suppress NO_X formation, and (3) post-combustion, catalytic controls to selectively reduce NO_X.[6]

The categories of retrofit control equipment identified for combustion turbines during a comprehensive review of the RBLC are reported in Table 2. A detailed discussion, including a description, the technical feasibility, and the anticipated performance of each control, is provided below.

Table 2. Potential Control Options for Combustion Turbines

Control Equipment	Technically Feasible	NO_X Control Efficiency
Good Combustion Practices and Fuel Selection	Base Case	N/A
Dry Low NO_X	For M5322B Only	46%
Water/Steam Injection	Yes	15%
Selective Catalytic Reduction	No	N/A

2.1.2.1. Good Combustion Practices and Fuel Selection

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. Applying concepts from engineering knowledge, experience, and the manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for the equipment involved, and using pipeline quality natural gas. If good combustion practices are maintained, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from combustion turbines; therefore, it has been determined that this method of NO_X control is feasible for the units at Blanco. However, these practices are currently in use at Blanco, as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices has been included in this report.

2.1.2.2. Dry Low NO_X Combustor

The key factors in thermal NO_X formation are the combustion temperature and the residence time of fuel in the combustor. Dry low NO_X burners reduce NO_X emissions by reducing both of these factors. Ultimately, this is accomplished by optimizing the air-to-fuel ratio. According to information received from Baker Hughes, a dry low NO_X burner can reduce NO_X exhaust concentrations to 35 ppmv on the GE M5322B unit (Unit T-DO1), corresponding to a control efficiency of 46%. Currently, per Baker Hughes, there are no dry low NOx burners commercially available for the GE 5221W units (Units T-CO1 and T-CO2).

[6] Ibid.

2.1.2.3. Water/Steam Injection

Water or steam injection is a technology that has been demonstrated to effectively suppress NO_X emissions from gas turbines. The effect of water and stream injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.

Water or steam injection is capable of reducing NO_x formation in the GE turbines at Blanco. Since the vendor cannot guarantee a control efficiency until the equipment has been installed and tested, Enterprise is estimating the reduction efficiency to be 15% based on AP-42.[7]

Enterprise engineers have stated that water or steam injection is feasible for the GE 5221W and M5322B turbines.

2.1.2.4. Selective Catalytic Reduction Systems

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust stream at a point downstream of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[8] The chemical reactions for this process are shown in the equations below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O \qquad \text{(Equation 1)}$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O \qquad \text{(Equation 2)}$$

An SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and electronic control system. The electronic controls regulate the quantity of reagent injected as a function of turbine load, speed, and temperature, so NO_X emissions reductions can be achieved. The lifespan of the catalyst is primarily determined by poisoning of active sites by flue gas constituents; thermal sintering, or compacting, of active sites due to high temperatures in the reactor; fouling caused by ammonia-sulfur salts and particulate matter in the gas; and erosion due to high gas velocities.[9]

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as ammonia slip. Unreacted ammonia in the exhaust can form ammonium sulfates, which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.[10]

In order for the SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 °F and 850 °F), dependent on the material of the catalyst. Exhaust gas temperatures greater than the upper limit will cause the NO_X and ammonia to pass through the catalyst unreacted.[11]

---

[7] Ibid.
[8] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
[9] Ibid.
[10] Ibid.
[11] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines."

An onsite evaluation was conducted at the Blanco facility during which measurements were taken of any feasible locations for SCR equipment. These measurements took into consideration the amount of buffer space needed to maintain accessibility to equipment and to avoid compromising worker safety. Based on size estimates of SCR units provided by CECO-Peerless, Enterprise determined that it is not possible to install these units at the Blanco Facility.

Enterprise has evaluated the costs of implementing the technically feasible control technologies at Blanco as thoroughly as possible in the time provided to complete this assessment. The cost estimates presented below are calculated according to methods and recommendations described in the EPA Air Pollution Control Cost Manual.[12]

Emission inventory data and stack tests from 2016 were used to assess the baseline emissions for these units.

3.1. GE 5221W TURBINE CONTROLS

Table 3. Cost Analysis Summary of Technically Feasible Controls for GE 5221W Turbines

Control Equipment	Unit No.	Cost Effectiveness	Cost Factors
Water Injection	T-CO1	$79,086 per ton	Equipment, engineering, and installation cost. Operating and incremental OEM inspection costs.
	T-CO2	$57,206 per ton	
Steam Injection	T-CO1	$110,101 per ton	Equipment, engineering, and installation cost. Operating and incremental OEM inspection costs.
	T-CO2	$79,640 per ton	

3.1.1. Water Injection

Enterprise received a cost estimate from Baker Hughes to implement water injection control on the GE 5221W turbines at the Blanco Compressor Station (Units T-CO1 and T-CO2). This cost estimate is $6.1 million per unit in equipment cost, plus an additional $1.2 million per unit associated with annual operating cost. The control efficiency for water injection is estimated to be 15%, resulting in an emission rate reduction of 23.79 tpy and 32.89 tpy for Units T-CO1 and T-CO2, respectively. The projected useful life of this control equipment is 15 years. This results in an estimated control cost effectiveness of $79,086 per ton and $57,206 per ton of reduced NO_X emissions for Units T-CO1 and T-CO2, respectively.

3.1.2. Steam Injection

Enterprise received a cost estimate from Baker Hughes to implement steam injection control on the GE 5221W turbines at the Blanco Compressor Station. This cost estimate is $8.1 million per unit in equipment cost, plus an additional $1.7 million per unit associated with annual operating cost. The control efficiency for steam injection is estimated to be 15%, resulting in an emission rate reduction of 23.79 tpy and 32.89 tpy for Units T-CO1 and T-CO2, respectively. The projected useful life of this control equipment is 15 years. This results in an estimated control cost effectiveness of $110,101 per ton and $79,640 per ton of reduced NO_X emissions for Units T-CO1 and T-CO2, respectively.

[12] U.S. EPA, "Air Pollution Control Cost Manual," available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

3.2. GE M5322B TURBINE CONTROLS

Table 4. Cost Analysis Summary of Technically Feasible Controls for GE M5322B Turbine

Control Equipment	Unit No.	Cost Effectiveness	Cost Factors
Dry Low NO_X	T-DO1	$9,934 per ton	Equipment, engineering, and installation cost. Operating and incremental OEM inspection costs.
Water Injection	T-DO1	$63,551 per ton	Equipment, engineering, and installation cost. Operating and incremental OEM inspection costs.
Steam Injection	T-DO1	$88,474 per ton	Equipment, engineering, and installation cost. Operating and incremental OEM inspection costs.

3.2.1. Dry Low NO_X

For the GE M5322B turbine (Unit T-DO1), Enterprise received a capital cost estimate from Baker Hughes for the dry low NO_X control equipment of $8.2 million. Based on information received from Baker Hughes, Enterprise estimates that other annual costs associated with inspections, maintenance, and repairs will be $44,986. The expected useful life of this control equipment is 20 years. Baker Hughes reported a lower target NO_X concentration of 35 ppm. The corresponding control efficiency of the dry low NO_X burner is therefore 46%, or an annual NO_X emission reduction of 91.04 tpy. This results in an amortized cost effectiveness of $9,934 per ton of reduced NO_X emissions.

3.2.2. Water Injection

Enterprise received a cost estimate from Baker Hughes to implement water injection control on the GE M5322B turbine at the Blanco Compressor Station. This cost estimate is $6.1 million in equipment cost, plus an additional $1.2 million associated with annual operating costs. The control efficiency for water injection is estimated to be 15%, resulting in an emission rate reduction of 29.60 tpy. The projected useful life of this control equipment is 15 years. This results in an estimated control cost effectiveness of $63,551 per ton of reduced NO_X emissions.

3.2.3. Steam Injection

Enterprise received a cost estimate from Baker Hughes to implement steam injection control on the GE M5322B turbine at the Blanco Compressor Station. This cost estimate is $8.1 million in equipment cost, plus an additional $1.7 million associated with annual operating cost. The control efficiency for steam injection is estimated to be 15%, resulting in an emission rate reduction of 29.60 tpy. The projected useful life of this control equipment is 15 years. This results in an estimated control cost effectiveness of $88,474 per ton of reduced NO_X emissions.

4. TIME NECESSARY FOR COMPLIANCE

The second factor in this analysis is the time necessary for compliance. Consideration of this factor involves estimating the time required for a source to implement a potential control measure. This information is provided here in order to advise the NMED of Enterprise's projection of a reasonable compliance timeline based on the equipment and site-specific considerations that could affect the time necessary to comply.

Enterprise estimates that approximately 3 to 4 years would be needed to budget, design, procure, and construct those categories of control equipment discussed in this report that would be technically feasible to install on the respective units.

5. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS OF COMPLIANCE

This section addresses the potential energy and non-air quality environmental impacts that would result from installation of the technically feasible control options at Blanco. Consideration of energy impacts involves assessing the impact of a control measure on the amount of energy that the source would have to consume. Non-air quality environmental impacts are assessed based on the effect of the control on non-air environmental media. Some examples of non-air quality environmental impacts include water resource depletion, solid waste generation, increased noise and odor pollution, and increased land usage.

5.1. GE 5221W AND M5322B TURBINE CONTROLS

5.1.1. Dry Low NO_X Combustor

There would be no anticipated unique or site-specific energy or non-air quality environmental impacts from installation and operation of dry low NO_X burners on Unit T-DO1.

5.1.2. Water and Steam Injection

Water or steam injection is usually accompanied by an efficiency penalty (typically 2% to 3%) but an increase in power output (typically 5% to 6%).[13] The increase in power output results from the increased mass flow required to maintain the turbine inlet temperature at the manufacturer's specifications. Both CO and VOC emissions are significantly increased by water injection, with the level of CO and VOC emission increases dependent on the amount of water injection.[14] This increase in CO and VOC emissions could potentially warrant the installation of oxidation catalyst, resulting in significant additional costs to implement water injection.

[13] U.S. EPA, AP-42, Section 3.1.4.1, "Stationary Gas Turbines."

[14] Ibid.

6. REMAINING USEFUL LIFE OF SOURCES

The anticipated remaining useful life of each source is addressed here for the NMED's consideration. The assessment of this factor involves estimating how long the sources analyzed will remain in operation and the lifetime of potential control measures, accounting for equipment and site-specific limitations.

40 CFR Part 51, Appendix Y includes guidance on the characterization of this factor, stating that the remaining useful life of a source will typically be longer than the useful life of the emission control system.[15] Therefore, it is appropriate to annualize compliance costs based on the useful life of the control equipment, rather than the life of the source.

6.1. GE 5221W TURBINE CONTROLS

6.1.1. Water Injection

The estimated useful life of a water injection control system is 15 years. This estimate has been incorporated in the cost analysis section in calculating the total annualized cost of the control.

6.1.2. Steam Injection

The estimated useful life of a steam injection control system is 15 years. This estimate has been incorporated in the cost analysis section in calculating the total annualized cost of the control.

6.2. GE M5322B TURBINE CONTROLS

6.2.1. Dry Low NOx Combustor

The estimated useful life of a dry low NO_X burner is 20 years. This estimate has been incorporated in the cost analysis section in calculating the total annualized cost of the control.

6.2.2. Water Injection

The estimated useful life of a water injection control system is 15 years. This estimate has been incorporated in the cost analysis section in calculating the total annualized cost of the control.

6.2.3. Steam Injection

The estimated useful life of a steam injection control system is 15 years. This estimate has been incorporated in the cost analysis section in calculating the total annualized cost of the control.

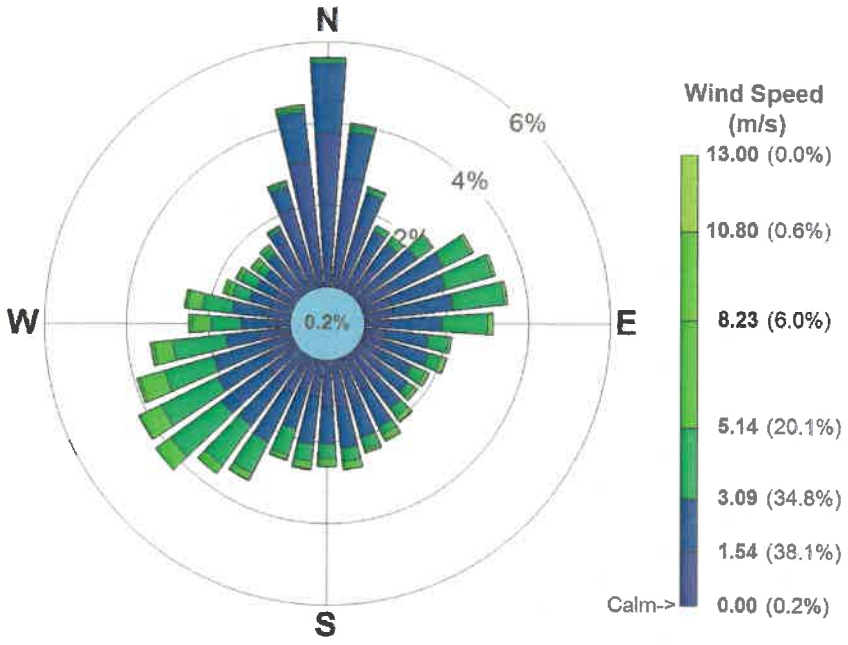
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[15] 40 CFR 51, Appendix Y, Section IV.D.4.k.

Enterprise does not believe that implementing any of the evaluated controls would meaningfully improve visibility in nearby Class I areas based on climatological data and ambient pollutant data.

The Blanco C&D Compressor Station is located approximately 50 miles from the Mesa Verde Class I area at a wind vector range of approximately 155 degrees to 165 degrees (SSE). According to 2015 meteorological data collected in Bloomfield, NM, which is presented in Figure 1 below, wind blows from this direction range at a frequency of only 2.4%. Moreover, when the wind direction is within this range, the wind speed is typically relatively low; the frequency of wind speeds greater than 3.09 m/s (or ~7 mph) is only 0.3%, or about 25 hours per year. Higher wind speeds would be needed to effectively transport emissions from Blanco to the Mesa Verde Class I area. Moreover, over the 50 miles of transport, pollutants undergo significant dispersion. While full dispersion and photochemical modeling would be needed to more robustly evaluate Blanco's impact, based on this evidence, Blanco's impact on visibility is likely insignificant.

Figure 1. Windrose Reporting 2015 Wind Direction and Speed in Bloomfield, NM



Additionally, according to aerosol composition data reported during visibility-impaired periods at the nearby San Pedro Parks and Mesa Verde IMPROVE Monitors, the main contributing pollutant to anthropogenic regional haze is ammonium sulfate.[16] Therefore, installing NO_X controls on the units at Blanco would not significantly improve visibility.

[16] See, e.g., U.S. EPA, Technical Support Document for EPA's Updated 2028 Regional Haze Modeling (Sept. 2019), App. B at pp. B-55 (Fig. 52), B-79 (Fig. 76); 2007 to 2017 Regional Haze Trends (https://www.env.nm.gov/wp content/uploads/sites/2/2019/02/2000_2017_trends-in-NM.pdf).

8. SUPPORTING DOCUMENTATION

Enterprise Field Services, LLC
Blanco C&D Compressor Station

GE 5221W Turbines	Interest Rate:	8.38%	
Unit T-CO1			
	Water/Steam Injection Period:	15 years	
Base Emissions			
NO_X ppm:		57.7 ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:		36.92 lb/hr	<-- From 2016 Stack Test Data
Hours of Operation:		8592 hrs	<-- From 2016 Stack Test Data
NO_X tpy:		158.60 tpy	<-- Calculated
Water Injection			
NO_X guarantee:		49 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:		31.38 lb/hr	
NO_X tpy:		134.81 tpy	
Total Capital Investment:	$ 6,116,700		<-- Equipment, Engineering & Installation
Annualized TCI:	$ 731,211		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,150,235		<-- Inspection and operating costs
Total Annual Costs:	$ 1,881,447		
Emissions Reduction:		23.79 tpy	
Cost Effectiveness:	**$ 79,086.07**	**$/ton**	
Steam Injection			
NO_X guarantee:		49 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:		31.38 lb/hr	
NO_X tpy:		134.81 tpy	
Total Cap Investment	$ 8,056,200		<-- Equipment, Engineering & Installation
Annualized TCI:	$ 963,066		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,656,226		<-- Inspection and operating costs
Total Annual Costs:	$ 2,619,292		
**Emissions Reduction:		23.79 tpy	
Cost Effectiveness:	**$ 110,101.19**	**$/ton**	

** Additional NOX emissions from the boiler are not considered in this emission reduction.

Enterprise Field Services, LLC
Blanco C&D Compressor Station

GE 5221W Turbines	Interest Rate:	8.38%	
Unit T-CO2			
	Water/Steam Injection Period:	15 years	
Base Emissions			
NO_X ppm:		83.2 ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:		51.56 lb/hr	<-- From 2016 Stack Test Data
Hours of Operation:		8505 hrs	<-- From 2016 Stack Test Data
NO_X tpy:		219.26 tpy	<-- Calculated
Water Injection			
NO_X guarantee:		71 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:		43.83 lb/hr	
NO_X tpy:		186.37 tpy	
Total Capital Investment:	$	6,116,700	<-- Equipment, Engineering & Installation
Annualized TCI:	$	731,211	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	1,150,235	<-- Inspection and operating costs
Total Annual Costs:	$	1,881,447	
Emissions Reduction:		32.89 tpy	
Cost Effectiveness:	**$**	**57,206.25**	**$/ton**
Steam Injection			
NO_X guarantee:		71 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:		43.83 lb/hr	
NO_X tpy:		186.37 tpy	
Total Cap Investment	$	8,056,200	<-- Equipment, Engineering & Installation
Annualized TCI:	$	963,066	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	1,656,226	<-- Inspection and operating costs
Total Annual Costs:	$	2,619,292	
**Emissions Reduction:		32.89 tpy	
Cost Effectiveness:	**$**	**79,640.77**	**$/ton**

** Additional NOX emissions from the boiler are not considered in this emission reduction.

Enterprise Field Services, LLC
Blanco C&D Compressor Station

GE M5322B Turbines	Interest Rate:	8.38%	
Unit T-DO1			
	DLN Period:	20 years	
	Water/Steam Injection Period:	15 years	
Base Emissions			
NO_X ppm:		65.0 ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:		49.32 lb/hr	<-- From 2016 Stack Test Data
Hours of Operation:		8004 hrs	<-- From 2016 Stack Test Data
NO_X tpy:		197.37 tpy	<-- Calculated
Dry Low NO_X			
NO_X guarantee:		35 ppm	<-- From Baker Hughes
NO_X lb/hr:		26.57 lb/hr	
NO_X tpy:		106.33 tpy	
Total Cap Investment	$	8,205,400	<-- Equipment, Engineering & Installation
Annualized TCI:	$	859,415	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	44,986	<-- Incremental overhaul costs
Total Annual Costs:	$	904,401	
Emissions Reduction:		91.04 tpy	
Cost Effectiveness:	**$**	**9,934.37**	**$/ton**
Water Injection			
NO_X guarantee:		55 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:		41.92 lb/hr	
NO_X tpy:		167.76 tpy	
Total Cap Investment:	$	6,116,700	<-- Equipment, Engineering & Installation
Annualized TCI:	$	731,211	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	1,150,235	<-- Inspection and operating costs
Total Annual Costs:	$	1,881,447	
Emissions Reduction:		29.60 tpy	
Cost Effectiveness:	**$**	**63,551.77**	**$/ton**
Steam Injection			
NO_X guarantee:		55 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:		41.92 lb/hr	
NO_X tpy:		167.76 tpy	
Total Cap Investment	$	8,056,200	<-- Equipment, Engineering & Installation
Annualized TCI:	$	963,066	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	1,656,226	<-- Inspection and operating costs
Total Annual Costs:	$	2,619,292	
Emissions Reduction:		29.60 tpy	
Cost Effectiveness:	**$**	**88,474.82**	**$/ton**

Enterprise Products

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS HOLDINGS LLC
(General Partner)

ENTERPRISE PRODUCTS OPERATING LLC

February 14, 2020

7018 1830 0001 4771 5728
Return Receipt Requested

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505

Re: NMED Follow-Up Letter Response
Regional Haze Four-Factor Analysis
Enterprise Field Services, LLC
Blanco C&D Compressor Station

Mr. Singleton:

Enterprise Field Services, LLC (Enterprise) submits herein to the New Mexico Environment Department (NMED) the enclosed responses to the follow-up questions contained in NMED correspondence dated December 23, 2019 for the Regional Haze Four-Factor Analysis submitted for the Enterprise Blanco C&D Compressor Station located in San Juan County, New Mexico.

Enterprise considers the information included in Appendix C of the enclosed response to be confidential business information (CBI) and request that it be treated as such to the full extent applicable.

Should you have questions or require further information regarding this submittal, please contact Tucker Jacobson at (713) 381-4313 (wtjacobson@eprod.com) or Bradley Cooley at (713) 381-5828.

Thank you,
Enterprise Field Services, LLC

W. Tucker Jacobson
Scientist, Senior Environmental

pranav kulkarni

Bradley J. Cooley, P.E.
Senior Manager, Permitting

/bjm
Enclosure

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REGIONAL HAZE FOUR-FACTOR ANALYSIS
NMED FOLLOW-UP LETTER RESPONSE
Enterprise Field Services, LLC, Blanco C & D Compressor Station

Prepared By:

Adam Erenstein – Manager of Consulting Services
Jake Zenker - Consultant

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February 2020

Project 203201.0009

Trinity Consultants

Environmental solutions delivered uncommonly well

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The NMED posed the following questions regarding the emissions control options Enterprise presented for the three (3) GE turbines: 5221W (2); 5322B (1).

1. SELECTIVE CATALYTIC REDUCTION (SCR) TECHNOLOGY

a. *You rejected consideration of SCR technology (CECO-Peerless) on account of space considerations; please provide more details on the specific dimensions and space required for SCR.*

Response: Enterprise received information from CECO-Peerless (Natalie Boone) on October 17, 2019, which stated that an area of approximately 40' by 20' is required for an SCR unit. This correspondence is included in Appendix C. As mentioned in our original report, space at the Blanco C & D Compressor Station is restricted. We have included aerial images in Appendix A of the facility with measurement overlays to demonstrate that the limited space precludes the option of installing an SCR.

b. *Please also provide an estimated NO_X control efficiency.*

Response: Because, as discussed above, space limitations at the Blanco C & D Compressor Station would preclude the installation of an SCR, and the control technology is therefore technically infeasible, the control efficiency was not estimated. However, based on information provided in AP-42 Section 3.1.4.3, an SCR can control NO_X emissions from turbines with a minimum efficiency of approximately 65%.[1]

2. WATER/STEAM INJECTION

a. *Your reported reduction effectiveness of 15% appears to be on the low side; a literature search suggests efficiencies greater than 50% to be more common. The AP-42 3.1.4.1 section you refer to in your analysis, in particular, indicates achievable NO_X reduction on the order of 60%. Table 3.1-1 within the same AP-42 document shows reduction from an uncontrolled 0.32 lb NO_X/MMBtu to 0.13 lb NO_X/MMBtu via Water-Steam Injection. Please clarify your 15% determination.*

Response: According to the Alternative Control Techniques document and the EPA Assessment of Non-EGU NO_X Emission Controls, NO_X can typically be controlled to 42 ppmv.[2, 3] The cost calculations have been updated to reflect this and are included in Appendix B. It should be noted that, as described in Section 2.1.2.3 of the original report, the original equipment manufacturer (General Electric) cannot guarantee a control efficiency for water/steam injection on the three turbines until the equipment has been installed and tested, which is the basis of using the AP-42 reduction efficiency of 15% in the original report. At this time, a third party

[1] AP-42 Section 3.1.4.3 Stationary Gas Turbines, Control Technologies, Catalytic Reduction System.

[2] Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007. https://www3.epa.gov/airquality/ctg_act/199301_nox_epa453_r-93-007_gas_turbines.pdf

[3] Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance Final TSD. Docket ID No. EPA-HQ-OAR-2015-0500. https://www.env.nm.gov/wp-content/uploads/sites/2/2019/02/final_assessment_of_non-egu_nox_emission_controls_cost_of_controls_and_time_for_compliance_final_tsd-1.pdf

vendor has not been identified and no performance guarantee has been obtained for water/steam injection.

b. *Your mention of increased CO and Unburned Hydrocarbons (UHC) with this technology can, in fact, be mitigated through the water/fuel ratio, with lower ratios favoring smaller increases in undesired CO and UHC. How have you considered this in your analysis?*

Response: This mitigation technique is not discussed in AP-42 or the Alternative Control Techniques document, so this was not directly considered.[4] A literature review indicated, and NMED's question appears to recognize, that increases in VOC and CO emissions may result from use of this technology. Although it may be possible to mitigate the resulting VOC and CO emission increases with changes to the water/fuel ratio, emissions of those pollutants would nevertheless increase with use of that technology, thereby potentially reducing visibility improvement.

3. COST EFFECTIVENESS (*DRY LOW NO_X*)

a. *Please provide a vendor quote from Baker Hughes for the Dry Low NO_X system proposed for the GE 5322B turbine.*

Response: A vendor quote from Baker Hughes for the dry low NO_X burner is attached in Appendix C.

b. *Are there no other vendors who make similar systems that could be fitted to the GE 5221W turbines?*

Response: Baker Hughes is a subsidiary of General Electric. As mentioned in the original four-factor report, Baker Hughes/GE does not offer dry low NO_X technology for this unit. No vendors have been identified that would provide dry low NO_X technology with guaranteed NO_X performance.

4. EMISSIONS DATA

a. *Adjacent to the turbine NO_X emissions lb/hr and tpy data you provide in your analysis of Dry Low NO_X and Water/Steam Injection implementation is the statement, "from 2016 stack test data". Your 2016 Emissions Inventory submittal, however, does not match the data presented in your analysis (Unit T-CO1: 36.92 lb/hr, 158.60 tpy; Unit T-CO2: 51.56 lb/hr, 219.26 tpy; Unit T-DO1: 49.32 lb/hr, 197.37 tpy). Further observation of your 2016 Emissions Inventory supplemental attachment reveals lb/hr values for the turbine units do not match the ones you used in the analysis. Please clarify.*

Response: The stack tests conducted in 2016 at the facility, which reference the emissions, are included with this submission in Appendix D. The stack tests are the most accurate representation of engine emissions during 2016. These emissions, along with the hours of operation of each unit recorded that year, were used to represent the baseline emissions

[4] AP-42 Section 3.1.4.1 Stationary Gas Turbines, Control Technologies, Water Injection.

reported in the four-factor analysis report.

5. OTHER CONTROL OPTIONS

a. Have you considered other options not otherwise listed in your 4-Factor Analysis?

i. Staged Combustion

Response: AP-42 Section 3.1.2 provides a technical background on turbine combustion. The second paragraph of that section describes lean-premixed staged combustion.[5] That paragraph defines lean-premixed staged combustion as a synonym for dry low NO_X. If such a technology were to be implemented, it would not be appropriate to use a third-party vendor. The Baker Hughes (a General Electric subsidiary) dry low NO_X equipment is specifically designed to work effectively with GE turbines and has been robustly demonstrated on the GE M5322B turbine. While it may be possible to install a third-party burner on GE turbines, the performance cannot be guaranteed.

ii. Ultra-Lean Combustion

Response: Ultra-lean combustion is informally defined as dry low NO_X technology that can achieve relatively low NO_X emissions compared to dry low NO_X. However, there is no formal definition of this technology that clearly delineates ultra-low NO_X or ultra-lean combustion from lean combustion. As part of the original four-factor analysis, Enterprise requested information on the most effective dry low NO_X units currently available and used the information it received in preparing that analysis.

iii. Post-Combustion other than SCR (e.g., XONON, SCONO$_X$, NSCR)

Response: XONON is not a post-combustion technology. The XONON combustor is completely contained within the combustion chamber of the turbine. As stated in the US EPA Environmental Technology Verification report, "The design of each Xonon™ combustor is customized to the particular turbine model and operating conditions of the application and would typically be defined through a collaborative effort with the manufacturer of the turbine to integrate the hardware into the design."[6] Moreover, the Air Pollution Training Institute Manual for Controlling NO_X Formation in Gas Turbines states that, "Both GE and Solar Turbines have successfully operated on a 7.5 MW and a 10 MW engine using the XONON combustion system. Both engines demonstrated performance at less-than 2.5 ppmvd at 15% O2, but neither has yet made them commercially available, and it is not likely that they will."[7]

SCONO$_X$ was not identified in an exhaustive query of the RACT/BACT/LAER Clearinghouse (RBLC) and was not considered to be a widely implemented technology. Therefore, this technology was not considered. AP-42 Section 3.1.4.4 also states that the limited emission data available for SCONO$_X$ units cannot be used to robustly verify the manufacturer's claims for these units. Moreover, the technology is referred to as a "niche" technology, catering to a narrow range of turbines, in a DOE technical cost analysis document evaluating the costs of NO_X

[5] AP-42 Section 3.1.2 Stationary Gas Turbines, Process Description.

[6] Environmental Technology Verification Report – NO_X Control Technologies: Catalytica Combustion Systems, Inc. Xonon™ Flameless Combustion System, at 2 (December 2000). https://archive.epa.gov/nrmrl/archive-etv/web/pdf/05_vr_xonon.pdf

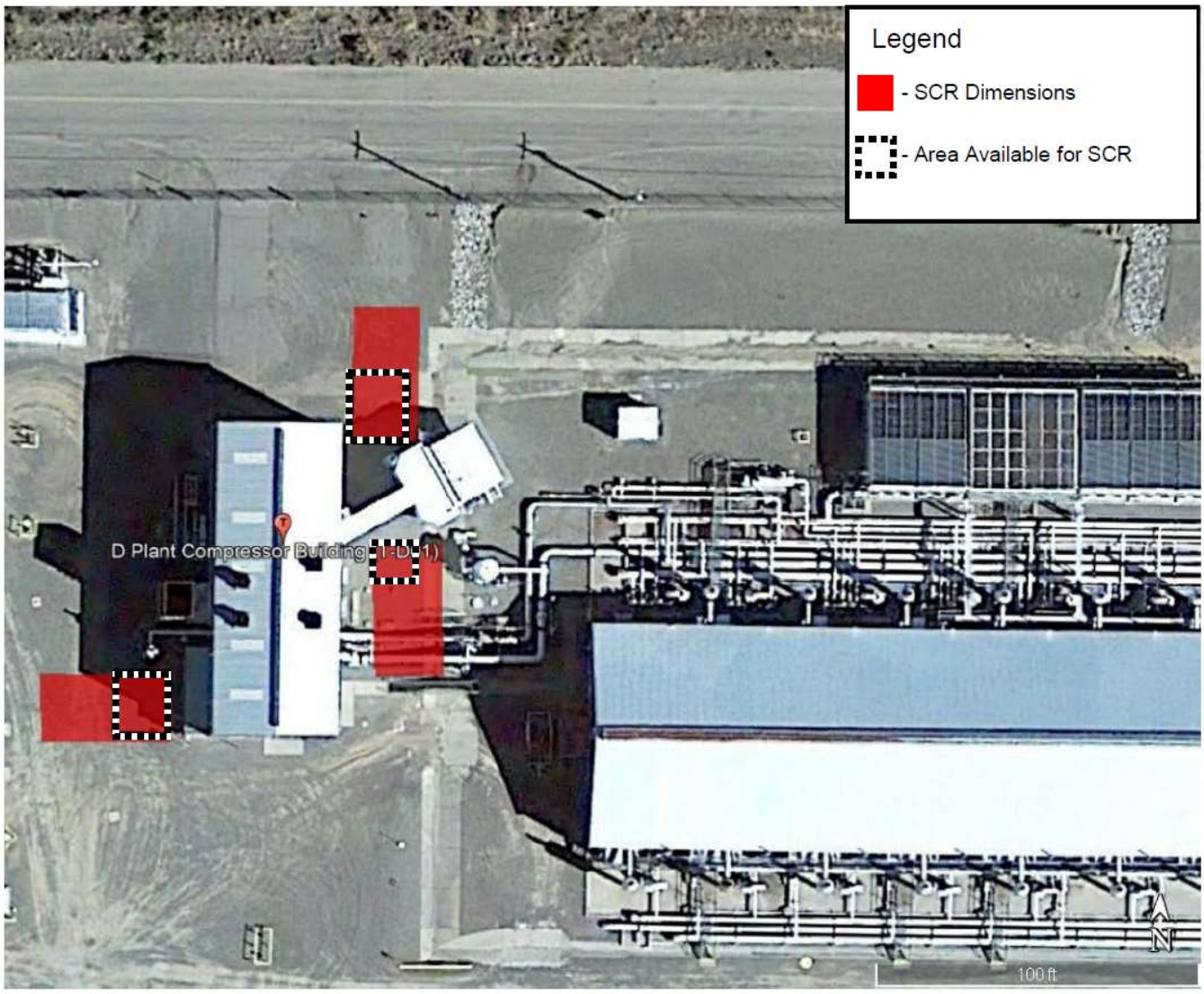
[7] Air Pollution Training Manual Chapter 7 – Controlling NO_X Formation in Gas Turbines, at p. 7-7 (September 2009). https://www.apti-learn.net/lms/register/display_document.aspx?dID=39

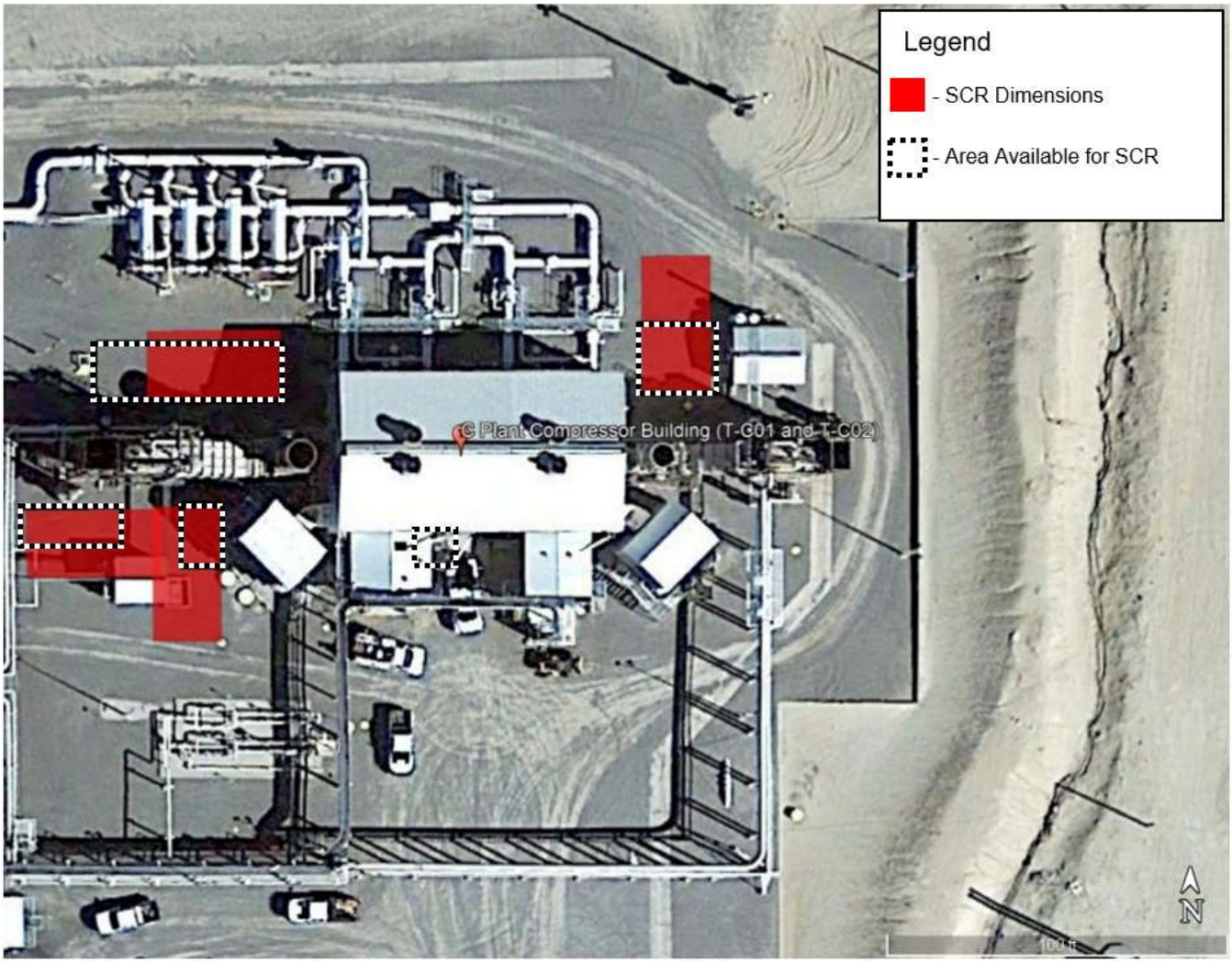
controls for turbines.[8] In this cost analysis, the cost per ton of NO_X controlled for the class of turbines installed at the Blanco C & D Compressor Station was greater than $16,000 (Table A-1). As that table in the cost analysis indicates, this technology is only relatively cost effective for turbines of at least 150 MW, or those typically used for power generation.

NSCRs were not identified in either the RBLC or AP-42 as a control option for turbines and were therefore not considered.[9]

[8] Cost Analysis of NO_X Control Alternatives for Stationary Gas Turbines, at p. 3-11, Contract No. DE-FC02-97CHIO877, prepared for the DOE. https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf

[9] AP-42 Section 3.1.4.3 Stationary Gas Turbines, Control Technologies, Catalytic Reduction Systems.


Legend
- SCR Dimensions
- Area Available for SCR
D Plant Compressor Building (1-DU1)
N
100 ft


Legend
- SCR Dimensions
- Area Available for SCR
C Plant Compressor Building (T-G01 and T-C02)
N

APPENDIX B: UPDATED COST CALCULATIONS

Enterprise Field Services, LLC

Blanco C&D Compressor Station

GE 5221W Turbines	Interest Rate:	8.38%	
Unit T-CO1			
	Water/Steam Injection Period:	15 years	
Base Emissions			
NO_X ppm:	57.7	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:	36.92	lb/hr	<-- From 2016 Stack Test Data
Hours of Operation:	8592	hrs	<-- From 2016 Stack Test Data
NO_X tpy:	158.60	tpy	<-- Calculated
Water Injection			
NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X lb/hr:	26.87	lb/hr	
NO_X tpy:	115.44	tpy	
Total Capital Investment:	$ 6,116,700.00		<-- Equipment Installation & Engineering
Annualized TCI:	$ 731,211		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,150,235		<-- Inspection and operating costs
Total Annual Costs:	$ 1,881,447		
Emissions Reduction:	43.15	tpy	
Cost Effectiveness:	**$ 43,598.09**	**$/ton**	
Steam Injection			
NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X lb/hr:	26.87	lb/hr	
NO_X tpy:	115.44	tpy	
Total Cap Investment	$ 8,056,200.00		<-- Equipment Installation & Engineering
Annualized TCI:	$ 963,066		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,656,226		<-- Inspection and operating costs
Total Annual Costs:	$ 2,619,292		
**Emissions Reduction:	43.15	tpy	
Cost Effectiveness:	**$ 60,695.91**	**$/ton**	

** Additional NOX emissions from the boiler are not considered in this emission reduction.

Enterprise Field Services, LLC

Blanco C&D Compressor Station

GE 5221W Turbines	Interest Rate:	8.38%	
Unit T-CO2			
	Water/Steam Injection Period:	15 years	

Base Emissions			
NO_X ppm:	83.2	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:	51.56	lb/hr	<-- From 2016 Stack Test Data
Hours of Operation:	8505	hrs	<-- From 2016 Stack Test Data
NO_X tpy:	219.26	tpy	<-- Calculated

Water Injection			
NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X lb/hr:	26.03	lb/hr	
NO_X tpy:	110.68	tpy	
Total Capital Investment:	$ 6,116,700.00		<-- Equipment Installation & Engineering
Annualized TCI:	$ 731,211		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,150,235		<-- Inspection and operating costs
Total Annual Costs:	$ 1,881,447		
Emissions Reduction:	108.58	tpy	
Cost Effectiveness:	**$ 17,328.49**	**$/ton**	

Steam Injection			
NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X lb/hr:	26.03	lb/hr	
NO_X tpy:	110.68	tpy	
Total Cap Investment	$ 8,056,200.00		<-- Equipment Installation & Engineering
Annualized TCI:	$ 963,066		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,656,226		<-- Inspection and operating costs
Total Annual Costs:	$ 2,619,292		
**Emissions Reduction:	108.58	tpy	
Cost Effectiveness:	**$ 24,124.20**	**$/ton**	

** Additional NOX emissions from the boiler are not considered in this emission reduction.

Enterprise Field Services, LLC

Blanco C&D Compressor Station

GE M5322B Turbine	Interest Rate:	8.38%		
Unit T-DO1				
	DLN Period:	20	years	
	Water/Steam Injection Period:	15	years	
Base Emissions				
NO_X ppm:		65.0	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:		49.32	lb/hr	<-- From 2016 Stack Test Data
Hours of Operation:		8004	hrs	<-- From 2016 Stack Test Data
NO_X tpy:		197.37	tpy	<-- Calculated
Dry Low NO_X				
NO_X guarantee:		35	ppm	<-- From Baker Hughes
NO_X lb/hr:		26.57	lb/hr	
NO_X tpy:		106.33	tpy	
Total Cap Investment	$	8,205,400		<-- Equipment cost (from Baker Hughes); associated installation and engineering costs.
Annualized TCI:	$	859,415		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	44,986		<-- Incremental overhaul costs
Total Annual Costs:	$	904,401		
Emissions Reduction:		91.04	tpy	
Cost Effectiveness:	**$**	**9,934.37**	**$/ton**	
Water Injection				
NO_X guarantee:		42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X lb/hr:		31.88	lb/hr	
NO_X tpy:		127.59	tpy	
Total Cap Investment:	$	6,116,700		<-- Equipment installation and engineering
Annualized TCI:	$	731,211		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	1,150,235		<-- Inspection and operating costs
Total Annual Costs:	$	1,881,447		
Emissions Reduction:		69.77	tpy	
Cost Effectiveness:	**$**	**26,965.69**	**$/ton**	
Steam Injection				
NO_X guarantee:		42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X lb/hr:		31.88	lb/hr	
NO_X tpy:		127.59	tpy	
Total Cap Investment	$	8,056,200		<-- Equipment installation and engineering
Annualized TCI:	$	963,066		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	1,656,226		<-- Inspection and operating costs
Total Annual Costs:	$	2,619,292		
Emissions Reduction:		69.77	tpy	
Cost Effectiveness:	**$**	**37,540.80**	**$/ton**	

REFER TO CONFIDENTIAL BUSINESS INFORMATION (CBI) ATTACHMENT

APPENDIX D: 2016 STACK TEST DATA

ENTERPRISE PRODUCTS OPERATING, L.P.

Annual Emission Test Results

Unit Operating Data		
Turbine Speed	**5095**	rpm
Turbine Manifold Pressure	**76.00**	psig
Turbine Site Horsepower	22280	hp
Estimated Turbine Horsepower	**21611.6**	hp
Estimated Turbine % Load	97%	hp
Turbine Fuel Consumption	**2905**	cf/min
Turbine Fuel Consumption	174300	cf/hr
Turbine BSFC	**8096**	BTU/bhp hr
Turbine Fuel BTU Content (HHV)	1003.79	BTU
Exhaust Temperaturee	**875**	°F

Test Run Number	Run 1	Run 2	Run 3
Start Time	07:12:03	08:22:11	09:32:19
Stop Time	08:12:02	09:22:11	10:32:20

Measured Emissions	Run 1	Run 2	Run 3	
NO	49.62	54.19	53.19	ppm
NO_2	5.33	5.42	5.32	ppm*
NOx	54.95	59.61	58.51	ppm
CO	7.52	5.00	5.38	ppm
O_2	15.00	15.00	15.00	%

Emission Rates

NOx Measured	35.42	38.42	37.71	lbs/hr
CO Measured	2.95	1.96	2.11	lbs/hr

	Average	**Permit Limit**		
NOx Measured	**36.92**	**80**	**lbs/hr**	**Passed**
CO Measured	**2.45**	**17.8**	**lbs/hr**	**Passed**

* NO_2 equals 10% NO or actual value whichever is higher per NMAQ SOP

ENTERPRISE PRODUCTS OPERATING, L.P.

Annual Emission Test Results

Unit Operating Data

Turbine Speed	**5091**	rpm
Turbine Manifold Pressure	**74.00**	psig
Turbine Site Horsepower	22280	hp
Estimated Turbine Horsepower	**21834.4**	hp
Estimated Turbine % Load	98%	hp
Turbine Fuel Consumption	**2825**	cf/min
Turbine Fuel Consumption	169500	cf/hr
Turbine BSFC	**7792**	BTU/bhp hr
Turbine Fuel BTU Content (HHV)	1003.79	BTU
Exhaust Temperaturee	**889**	°F

Test Run Number	Run 1	Run 2	Run 3
Start Time	10:46:17	11:56:27	13:06:36
Stop Time	11:46:17	12:56:27	14:06:36

Measured Emissions	Run 1	Run 2	Run 3	
NO	74.00	75.57	77.33	ppm
NO_2	7.40	7.56	7.73	ppm*
NOx	81.40	83.13	85.07	ppm
CO	2.00	2.14	2.62	ppm
O_2	15.00	15.00	15.00	%

Emission Rates

NOx Measured	51.02	52.11	53.32	lbs/hr
CO Measured	0.76	0.82	1.00	lbs/hr

	Average	**Permit Limit**		
NOx Measured	**51.56**	**80**	**lbs/hr**	**Passed**
CO Measured	**0.79**	**17.8**	**lbs/hr**	**Passed**

* NO_2 equals 10% NO or actual value whichever is higher per NMAQ SOP

ENTERPRISE PRODUCTS OPERATING, L.P.

Annual Emission Test Results

Unit Operating Data

Turbine Speed	**5055**	rpm
Turbine Manifold Pressure	**76.00**	psig
Turbine Site Horsepower	22280	hp
Estimated Turbine Horsepower	**21166**	hp
Estimated Turbine % Load	95%	hp
Turbine Fuel Consumption	**3725**	cf/min
Turbine Fuel Consumption	223500	cf/hr
Turbine BSFC	**10599**	BTU/bhp hr
Turbine Fuel BTU Content (HHV)	1003.79	BTU
Exhaust Temperaturee	**905**	°F

Test Run Number	Run 1	Run 2	Run 3
Start Time	08:38:11	09:48:19	10:58:30
Stop Time	09:38:11	10:48:19	11:58:29

Measured Emissions	Run 1	Run 2	Run 3	
NO	49.15	56.00	68.50	ppm
NO_2	7.00	7.20	7.05	ppm*
NOx	56.15	63.20	75.55	ppm
CO	8.85	7.70	5.95	ppm
O_2	15.00	15.00	15.00	%

Emission Rates

NOx Measured	46.41	52.23	62.44	lbs/hr
CO Measured	4.45	3.87	2.99	lbs/hr

	Average	**Permit Limit**		
NOx Measured	**49.32**	**80**	**lbs/hr**	**Passed**
CO Measured	**4.16**	**17.8**	**lbs/hr**	**Passed**

* NO_2 equals 10% NO or actual value whichever is higher per NMAQ SOP

Enterprise Field Services, LLC
Blanco C&D Compressor Station

GE 5221W Turbines
Unit T-CO1

Interest Rate: 8.38%

Water/Steam Injection Period: 15 years

Base Emissions

NO_X ppm:	51.2	ppm	<-- Average of 2016-2018 Stack Test Data
NO_X tpy:	139.23	tpy	<-- Average of 2016-2018 EI Data

Water Injection

NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:	114.13	tpy	
Total Capital Investment:	$ 6,116,700		<-- Equipment Installation & Engineering
Annualized TCI:	$ 731,211		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,150,235		<-- Inspection and operating costs
Total Annual Costs:	$ 1,881,447		
Emissions Reduction:	25.09	tpy	
Cost Effectiveness:	**$ 74,983.50**	**$/ton**	

Steam Injection

NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:	114.13	tpy	
Total Cap Investment	$ 8,056,200		<-- Equipment Installation & Engineering
Annualized TCI:	$ 963,066		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,656,226		<-- Inspection and operating costs
Total Annual Costs:	$ 2,619,292		
**Emissions Reduction:	25.09	tpy	
Cost Effectiveness:	**$ 104,389.71**	**$/ton**	

** Additional NOX emissions from the boiler are not considered in this emission reduction.

Enterprise Field Services, LLC
Blanco C&D Compressor Station

GE 5221W Turbines
Unit T-CO2

Interest Rate: 8.38%

Water/Steam Injection Period: 15 years

Base Emissions

NO_X ppm:	69.1	ppm	<-- Average of 2016-2018 Stack Test Data
NO_X tpy:	157.53	tpy	<-- Average of 2016-2018 EI Data

Water Injection

NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:	95.71	tpy	
Total Capital Investment:	$ 6,116,700		<-- Equipment Installation & Engineering
Annualized TCI:	$ 731,211		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,150,235		<-- Inspection and operating costs
Total Annual Costs:	$ 1,881,447		
Emissions Reduction:	61.83	tpy	
Cost Effectiveness:	**$ 30,430.00**	**$/ton**	

Steam Injection

NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:	95.71	tpy	
Total Cap Investment	$ 8,056,200		<-- Equipment Installation & Engineering
Annualized TCI:	$ 963,066		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,656,226		<-- Inspection and operating costs
Total Annual Costs:	$ 2,619,292		
**Emissions Reduction:	61.83	tpy	
Cost Effectiveness:	**$ 42,363.71**	**$/ton**	

** Additional NOX emissions from the boiler are not considered in this emission reduction.

Enterprise Field Services, LLC
Blanco C&D Compressor Station

GE M5322B Turbine
Unit T-DO1

Interest Rate: 8.38%

DLN Period: 20 years

Water/Steam Injection Period: 15 years

Base Emissions

NO_X ppm:	59.0	ppm	<-- From 2016-2018 Stack Test Data
NO_X tpy:	215.21	tpy	<-- Average of 2016-2018 EI Data

Dry Low NO_X

NO_X guarantee:	35	ppm	<-- From Baker Hughes
NO_X tpy:	127.69	tpy	
Total Cap Investment	$ 8,205,400		<-- Equipment cost (from Baker Hughes); associated installation and engineering costs.
Annualized TCI:	$ 859,415		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 44,986		<-- Incremental overhaul costs
Total Annual Costs:	$ 904,401		
Emissions Reduction:	87.52	tpy	
Cost Effectiveness:	**$ 10,333.82**	**$/ton**	

Water Injection

NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:	153.23	tpy	
Total Cap Investment:	$ 6,116,700		<-- Equipment installation and engineering
Annualized TCI:	$ 731,211		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,150,235		<-- Inspection and operating costs
Total Annual Costs:	$ 1,881,447		
Emissions Reduction:	61.98	tpy	
Cost Effectiveness:	**$ 30,355.46**	**$/ton**	

Steam Injection

NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:	153.23	tpy	
Total Cap Investment	$ 8,056,200		<-- Equipment installation and engineering
Annualized TCI:	$ 963,066		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,656,226		<-- Inspection and operating costs
Total Annual Costs:	$ 2,619,292		
Emissions Reduction:	61.98	tpy	
Cost Effectiveness:	**$ 42,259.93**	**$/ton**	

** Additional NOX emissions from the boiler are not considered in this emission reduction.

From: Jacobson, Tucker <WTJACOBSON@eprod.com>
Sent: Tuesday, May 19, 2020 3:48 PM
To: Zyla, Rhett, NMENV
Cc: Kulkarni, Pranav; Cooley, Bradley; Jake Zenker; Adam Erenstein
Subject: RE: Regional Haze 4-Factor Analysis: Carlsbad CS and Blanco C&D CS
Attachments: Enterprise Blanco C & D Compressor Station Follow-Up Response.pdf; Blanco C & D CS_Revised Cost Effectiveness Summary Tables.pdf

Hello Rhett,

Yes, we are doing all good. Hope you all are okay too.

I've responded to the 3 follow-up items below in purple font. Please let us know if you need additional details.

Thanks
Tucker

From: Zyla, Rhett, NMENV <Rhett.Zyla@state.nm.us>
Sent: Friday, May 15, 2020 3:04 PM
To: Jacobson, Tucker <WTJACOBSON@eprod.com>
Cc: Kulkarni, Pranav <pkulkarni@eprod.com>; Cooley, Bradley <bjcooley@eprod.com>; Jake Zenker <JZenker@trinityconsultants.com>; Adam Erenstein <AErenstein@trinityconsultants.com>
Subject: [EXTERNAL] RE: Regional Haze 4-Factor Analysis: Carlsbad CS and Blanco C&D CS

[Use caution with links/attachments]
Hello Tucker,

The NMED has been working on other regional haze issues since we last were in regular contact with 4-factor facilities in March.

I want to follow up on Blanco C&D Compressor Station.

1) The errors encountered with South Carlsbad CS conversion from the stack testing results for which the adjusted O2 was not considered, also applies to Blanco C&D. I did not review in detail the ppm values for the Blanco C&D in detail. Please revisit the data to make any appropriate adjustments as you did for South Carlsbad CS. As mentioned in the 3/17/20 email; NOx concentrations used in the Blanco C & D analysis were adjusted for oxygen so no changes are needed.

2) Water/Steam Injection for Blanco C&D: There seems to be an incongruence between the attainable reduction amount shown in South Carlsbad CS vs. Blanco C&D. In the former, you appropriately indicated the 42 ppm attainable from EPA data (even though you also reference the 15% reduction that I have been unable to confirm in AP-42 you referred to – and to which I had also referenced larger percentage reduction within that very publication). The 42 ppm appears to be the value to go with based on the most current EPA literature (while AP-42 is dated). Please adjust Blanco C&D to reflect the 42 ppm limit as was done with South Carlsbad CS. In our follow-up response dated 2/14/20 and subsequent cost effectiveness revision dated 2/26/20, the cost effectiveness for water and steam technologies on the three turbines at Blanco C & D were based on the ability to control NOx to a concentration of 42 ppm. Attached is a copy of the non-CBI portion of the submittals. Maybe I don't understand your question?

3) Please provide a more detailed record of Enterprise's cost calculations for South Carlsbad CS and Blanco C&D CS, that include breakdowns of Annual O&M Costs, as well as Total Capital Investment Costs. For the latter, for example, the Blanco C&D CS T-D01 dry low NOx system capital cost reported in your 4-factor submittal is $8,205,400; whereas, the information provided in your follow-up CBI on page 4 of 4 is notably less (value not mentioned for CBI purposes). NMED needs to confirm that all cost categories you have considered are valid costs to be considered for 4-factor analysis. Below is an example of another industry's itemized breakdown of its cost categories (annual and other categories not shown for brevity). What cost year was used for your analysis?
Costs were assumed at present day values. The cost listed on Page 4 of 4 of the CBI information for Blanco C & D was the Purchased Equipment Cost (PEC) quoted from the DLN equipment vendor and did not include the Direct Installation Cost (DC) or Indirect Installation Cost (IC); hence the difference from the amount listed in "Total Cap Investment" on the cost effectiveness spreadsheet.

The "Total Capital Investment" amount listed for each unit is based on the following:

Total Capital Investment = PEC + DC + IC

- PEC is based on the estimated technology equipment cost
- DC is based on 25% of PEC
- IC is based on the sum of the following:
  - 3rd Party Engineering (3.75% of PEC)
  - Inspection (3.75% of PEC)
  - Enterprise (3.125% of PEC)
  - Contingency (10% of PEC)

The sum of PEC, DC, and IC was rounded up to the nearest $100

The "Total Annual Cost" amount listed for each type of turbine is outlined below:

Water Injection

Total Annual O&M Cost = Annual Inspection/Overhaul Cost (provided by OEM) + (18% of PEC)

Steam Injection

Total Annual O&M Cost = Annual Inspection/Overhaul Cost (provided by OEM) + (20% of PEC)

SoloNOx and DLN

Total Annual O&M Cost = Annual Inspection/Overhaul Cost provided by OEM

CAPITAL COST

Direct Costs

- Purchased equipment costs
  - Reactor housing
  - Ammonia handling and injection
    - Ammonia Injection Grid & dilution skid
    - Anhydrous ammonia tank
    - Air Compressors (plant's existing has spare
    - Vaporizers
    - Ammonia unloading skids
    - Ammonia supply pump skid
    - Miscellaneousequipment/components
    - Mixing Chamber (included)
    - Piping (ammonia supply, etc)
  - Initial catalyst (Ceram)
  - Flue gas handling: ductwork
  - Air heater modifications
  - ASH handling (e.g. conveyors)
  - Electrical equipment
  - Structrual steel
  - ID Fan
  - Misc. equipment
    - Sonic horns
    - LPA screens / rappers
    - NOx/NH3 monitoring
    - Flow modeling
      - Subtotal capital cost (CC)
  - Instruments and controls
  - Taxes
  - Freight
    - Total purchased equipment cost (PEC)

- Direct installation costs
  - Subsurface construction
    - Earthwork, underground utilities, etc.
    - Foundations (including embedments)
  - Superstructures construction
    - Reactor housing, ductwork, etc.
  - Demo and Rebuild
  - Mechanical construction
  - Electrical construction
  - Spare parts, training, TA
    - Total direct installation costs (DIC)

Total direct costs (DC) = (PEC) + (DIC)

Thank you, and I hope all is well you, with Enterprise staff and their families and friends.

Rhett Zyla, EIT

Air Dispersion Modeling/Emissions Inventory

New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez
Santa Fe, NM 87505
505.476.4304 (O)
Rhett.Zyla@state.nm.us
https://www.env.nm.gov/air-quality

From: Jacobson, Tucker
To: Zyla, Rhett, NMENV
Cc: Kulkarni, Pranav; Cooley, Bradley; Jake Zenker; Adam Erenstein
Subject: [EXT] RE: Regional Haze 4-Factor Analysis: Carlsbad CS and Blanco C&D CS
Date: Tuesday, June 2, 2020 3:45:27 PM
Attachments: image015.png
image016.png
image017.png
image018.png
image019.png
image020.png

Rhett,

This is not a typo. Based on the information we have available, to estimate annual NOx emissions with control, we took the ratio of the controlled guarantee concentration and the base uncontrolled concentration then multiplied the ratio by the base annual uncontrolled emissions. Since we were asked to use the 2016-2018 average reported in Annual Emission Inventories as our base, it resulted in a different controlled emission rate when compared against the original estimate that was based only on 2016 data.

Original (2016): 35 ppm/65ppm x 197.37 tpy = 106.3 tpy

-

Revised (2016-2018): 35 ppm/59 ppm x 215.21 tpy = 127.6 tpy

Hope this helps.

Thanks
Tucker

From: Zyla, Rhett, NMENV <Rhett.Zyla@state.nm.us>
Sent: Monday, June 1, 2020 5:33 PM
To: Jacobson, Tucker <WTJACOBSON@eprod.com>
Cc: Kulkarni, Pranav <pkulkarni@eprod.com>; Cooley, Bradley <bjcooley@eprod.com>; Jake Zenker <JZenker@trinityconsultants.com>; Adam Erenstein <AErenstein@trinityconsultants.com>
Subject: [EXTERNAL] RE: Regional Haze 4-Factor Analysis: Carlsbad CS and Blanco C&D CS

[Use caution with links/attachments]
Hello Tucker,

There appears to be an inconsistency/typo in the revised vs original 4F control tpy values for Blanco C&D on T-DO1. See highlighted below: the guarantee 35 ppm is the same in both cases; this should yield the same lb/hr and tpy, all else equal.

Revised Cost Analysis:

Blanco C&D Compressor Station			
GE M5322B Turbine	Interest Rate:	8.38%	
Unit T-DO1			
	DLN Period:	20	y
	Water/Steam Injection Period:	15	y
Base Emissions			
NO_X ppm:		59.0 ppm	<
NO_X tpy:		215.21 tpy	<
Dry Low NO_X			
NO_X guarantee:		35 ppm	<
NO_X tpy:		127.69 tpy	
Total Cap Investment	$ 8,205,400		<
Annualized TCI:	$ 859,415		<
Annual O&M Costs:	$ 44,986		<
Total Annual Costs:	$ 904,401		
Emissions Reduction:		87.52 tpy	
Cost Effectiveness:	**$ 10,333.82**	**$/ton**	

Original Cost Analysis:

Blanco C&D Compressor Station			
GE M5322B Turbines	Interest Rate:	8.38%	
Unit T-DO1			
	DLN Period:	20	y
	Water/Steam Injection Period:	15	y
Base Emissions			
NO_x ppm:		65.0	ppm
NO_x lb/hr:		49.32	lb/hr
Hours of Operation:		8004	hrs
NO_x tpy:		197.37	tpy
Dry Low NO_x			
NO_x guarantee:		35	ppm
NO_x lb/hr:		26.57	lb/hr
NO_x tpy:		106.33	tpy
Total Cap Investment	$	8,205,400	
Annualized TCI:	$	859,415	
Annual O&M Costs:	$	44,986	
Total Annual Costs:	$	904,401	
Emissions Reduction:		91.04	tpy
Cost Effectiveness:	**$**	**9,934.37**	**$/ton**

Thank you,

Rhett Zyla, EIT

Air Dispersion Modeling/Emissions Inventory

New Mexico Environment Department

Air Quality Bureau

525 Camino de los Marquez

Santa Fe, NM 87505

505.476.4304 (O)

Rhett.Zyla@state.nm.us

https://www.env.nm.gov/air-quality

Enterprise Products

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS HOLDINGS LLC
(General Partner)

ENTERPRISE PRODUCTS OPERATING LLC

October 1, 2020

7019 1640 0001 3129 8761
Return Receipt Requested

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505

Re: NMED Follow-Up Discussion Response
Regional Haze Four-Factor Analysis
Enterprise Field Services, LLC
Blanco C & D Compressor Station

Mr. Singleton:

Enterprise Field Services, LLC ("Enterprise") submits herein to the New Mexico Environment Department (NMED) the responses to the follow-up requests from a virtual meeting held on August 28, 2020 for the Regional Haze Four-Factor Analysis submitted for the Enterprise Blanco C & D Compressor Station located in San Juan County, New Mexico. NMED requested information regarding six additional items identified as (a) through (f) in email correspondence dated September 2, 2020. Enterprise responded to each of the six items and committed to further developing and providing additional information for requests (b) and (c). The NMED follow-up requests and Enterprise responses for requests (b) and (c) are provided below.

Enterprise considers the information included in Attachment A of the enclosed response to be confidential business information (CBI) and requests that it be treated as such to the full extent of applicable law.

NMED Request (b): *We discussed an adjustment to the interest rate Enterprise originally used in its amortization of capital costs. You made an argument to use an interest rate higher than the adjusted rate of 3.25% NMED presented. Please provide in writing the reasoning for your higher interest rate (on top of the explanation provided in an email communication provided to NMED earlier this year), more precisely, the interest rate that would be specific to Enterprise for air pollution control projects. Note that no other New Mexico 4-factor submittal used an interest rate as high as the 8.38% you suggested would be appropriate to Enterprise. Providing official information from a potential lender would support your case when EPA and other entities review NMED's Regional Haze recommendations.*

Enterprise Response: In our original Four-Factor Analysis, Enterprise used an annual interest rate of 8.38% based on its application of a 2018 FERC rulemaking that reflected an average capital structure for Enterprise's industry of 57% equity (with an average 10.55% annual return) and 43%

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debt (to which Enterprise applied the then-applicable prime rate of 5.5%). This approach tracked the basic manner in which Enterprise's industry raises funds, i.e. through a combination of investment equity and taking on debt. The NMED's response stated that Enterprise's proposed rate "is appropriate for pipeline operation and construction, not for air pollution control technologies. The prime rate [3.25%] or a rate specific to Enterprise should be used, and a rate representative of 2020 conditions."

Enterprise respectfully disagrees with the NMED's statement that the FERC methodology is only appropriate for pipeline construction and operation. As noted during our August 28, 2020 virtual meeting, Enterprise's cost of capital is based on the company's overall health and financial condition and generally is not sensitive to the specific purpose for which capital is raised. Put another way, Enterprise would not expect to obtain a lower interest rate on expenses for air pollution control equipment than for other types of expenses such as pipeline construction and operation. Accordingly, we continue to believe that the 8.38% rate derived from the FERC methodology would have been suitable for the Four-Factor Analysis. We also do not believe that the NMED's proposed prime rate of 3.25%, which reflects highly unusual but ultimately temporary conditions in the economy as the result of the COVID-19 pandemic, is a suitable basis for calculating the cost of control measures that would be implemented years in the future when interest rates are likely to return to higher levels more commensurate with their historical patterns.

Nonetheless, at the NMED's request, Enterprise has calculated a company-specific interest rate of 9.62% as of June 30, 2020 and requests that the NMED rely on this interest rate to calculate the cost-effectiveness of potential control measures on our facilities. This interest rate was calculated by Enterprise's Finance department using the Capital Asset Pricing Model. We emphasize that this interest rate reflects our company's overall cost of capital and is applicable to capital raised for a range of purposes, including air pollution control costs, construction of new facilities, or otherwise. The specific calculations behind this interest rate are described in the confidential white paper included as Attachment A. Enterprise consents to disclosure of the 9.62% rate and this explanation in the NMED's public record. However, we request that the NMED treat the white paper itself (i.e. Attachment A) as our confidential business information.

Enterprise has revised the cost-effectiveness calculations for potential retrofit control technologies for the combustion units subject to the Four-Factor Analysis at the Blanco C & D Compressor Station using the calculated company-specific interest rate of 9.62%. The revised cost-effectiveness calculations are enclosed as Attachment B.

NMED Request (c): *Replacing turbines with electric compressors has not been excluded from consideration; therefore, a technical feasibility analysis and cost analysis is required. Given the deadline of September 10 for NMED to submit information to WRAP for the 2nd round PAC photochemical grid modeling, a qualitative ballpark estimate will suffice if you cannot put together a comprehensive analysis within the next week. However, a more complete analysis would be appreciated by the end of the month.*

Enterprise Response: To assess the potential conversion of combustion driven compressors to electric driven compressors, numerous significant considerations require evaluation. For the

purposes of this discussion, Enterprise has evaluated existing electrical capacity to determine the additional electrical capacity that likely would be required to provide equivalent station horsepower for the units that are subject to the Four-Factor Analysis. The total added electric load that would be required if the two GE Frame 5 turbines (T-CO1 and T-CO2) and one GE M5322B turbine (T-D01) were converted to electric driven units is approximately 63,000 kilowatts (KW) or 63 megawatts (MW). The electric provider, Farmington Electric Utility System (FEUS), is at peak capacity and therefore would need to invest in a new electricity generating station to provide the additional 63 MW needed. The cost of a new generating station is not included in the analysis but is estimated to cost approximately $2,500/KW, or $157,500,000 for 63 MW. Additionally, the increased electricity demand would require upgrades to the utility transmission infrastructure from the generating station to the Blanco C & D Compressor Station; these costs would be directly borne by Enterprise. The existing 2.5–mile, 69 kilovolt (kV) distribution system, including a substation, would need to be upgraded to 115 kV to provide the additional required load. In addition to replacing the three combustion driven compressor packages with electric compressor packages, Enterprise would need to construct additional utility infrastructure within the Blanco C & D Compressor Station to distribute the energy needed to drive the electric compressors. Cost-effectiveness figures for electrification of each unit (excluding third-party costs to install additional electricity generating capacity), including the cost estimation methodology used to estimate the total capital investment, is included in Attachment C. Please note that the electrification costs are based on best professional judgement and not reflective of an actual quoted facility-specific price. The timeline to implement electrification of the three units at the Blanco C & D Compressor Station would likely be between five and eight years, depending on the new third-party generating station source siting requirements, environmental permitting, and right of way negotiations. No consideration has been given to potential nitrogen oxide (NO_X) emissions as a result of generating the additional electrical capacity that would be necessary for electrification of the combustion units at the Blanco C & D Compressor Station.

Enterprise does not believe that any further evaluation of electrification of the three units at the Blanco C & D Compressor Station is warranted. Electrification is not technically feasible because of the necessary additional power generation and utility infrastructure upgrades needed by the local utility over which Enterprise has no control. Additionally, redefining a source is not a retrofit control technology and is beyond the authority of the Regional Haze Rule.

Should you have any questions regarding this submittal, please contact Tucker Jacobson at (713) 381-4313 (wtjacobson@eprod.com) or Bradley Cooley at (713) 381-5828.

Sincerely,

Enterprise Field Services, LLC

W. Tucker Jacobson
Scientist, Senior Environmental

Bradley J. Cooley, P.E.
Director, Environmental

/bmh
Enclosure

Attachment A (Confidential Business Information)

Company-Specific Interest Rate Calculation

The Confidential information in this Attachment meets the conditions of NMAC § 20.2.1.115.B(3), as follows. Enterprise considers the information to be confidential, and requests that it be treated as such to the full extent of applicable law. We have taken reasonable measures to protect the confidentiality by keeping the information in secure data systems that are only available to authorized users, who are subject to confidentiality obligations per company policy, and by making this confidentiality claim. Further, neither NMED nor a third party could obtain the information without our consent, as this is information developed by Enterprise.

Attachment B

Revised Cost-Effectiveness Calculations with Company-Specific Interest Rate

Enterprise Field Services, LLC

Blanco C&D Compressor Station

GE 5221W Turbine	Interest Rate:	9.62%	<-- Company-specific interest rate as of 6/30/20
Unit T-CO1			
	Water/Steam Injection Period:	15 years	

Base Emissions

NO_X ppm:	51.2	ppm	<-- Average of 2016-2018 Stack Test Data
NO_X tpy:	139.23	tpy	<-- Average of 2016-2018 EI Data

Water Injection

NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:	114.13	tpy	
Total Capital Investment:	$ 10,643,600		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,369,138		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,965,077		<-- Inspection and operating costs
Total Annual Costs:	$ 3,334,215		
Emissions Reduction:	25.09	tpy	
Cost Effectiveness:	**$ 132,882.37**	**$/ton**	

Steam Injection

NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:	114.13	tpy	
Total Cap Investment	$ 14,018,400		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,803,254		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 2,848,666		<-- Inspection and operating costs
Total Annual Costs:	$ 4,651,921		
**Emissions Reduction:	25.09	tpy	
Cost Effectiveness:	**$ 185,398.43**	**$/ton**	

** Additional NO_X emissions from the boiler are not considered in this emission reduction.

Enterprise Field Services, LLC

Blanco C&D Compressor Station

GE 5221W Turbine	Interest Rate:		9.62%	<-- Company-specific interest rate as of 6/30/20
Unit T-CO2				
	Water/Steam Injection Period:		15 years	
Base Emissions				
NO_X ppm:		69.1	ppm	<-- Average of 2016-2018 Stack Test Data
NO_X tpy:		157.53	tpy	<-- Average of 2016-2018 EI Data
Water Injection				
NO_X guarantee:		42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:		95.71	tpy	
Total Capital Investment:	$	10,643,600		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	1,369,138		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	1,965,077		<-- Inspection and operating costs
Total Annual Costs:	$	3,334,215		
Emissions Reduction:		61.83	tpy	
Cost Effectiveness:	**$**	**53,926.68**	**$/ton**	
Steam Injection				
NO_X guarantee:		42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:		95.71	tpy	
Total Cap Investment	$	14,018,400		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	1,803,254		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	2,848,666		<-- Inspection and operating costs
Total Annual Costs:	$	4,651,921		
**Emissions Reduction:		61.83	tpy	
Cost Effectiveness:	**$**	**75,238.89**	**$/ton**	

** Additional NO_X emissions from the boiler are not considered in this emission reduction.

Enterprise Field Services, LLC

Blanco C&D Compressor Station

GE M5322B Turbine
Unit T-DO1

Interest Rate:	9.62%		<-- Company-specific interest rate as of 6/30/20
DLN Period:	20	years	
Water/Steam Injection Period:	15	years	

Base Emissions

NO_X ppm:	59.0	ppm	<-- From 2016-2018 Stack Test Data
NO_X tpy:	215.21	tpy	<-- Average of 2016-2018 EI Data

Dry Low NO_X

NO_X guarantee:	35	ppm	<-- From Baker Hughes
NO_X tpy:	127.69	tpy	
Total Cap Investment	$ 14,278,000		<-- Control System Cost from Baker Hughes; estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,633,801		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 44,986		<-- Incremental overhaul costs
Total Annual Costs:	$ 1,678,787		
Emissions Reduction:	87.52	tpy	
Cost Effectiveness:	**$ 19,182.06**	**$/ton**	

Water Injection

NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:	153.23	tpy	
Total Cap Investment:	$ 10,643,600		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,369,138		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,965,077		<-- Inspection and operating costs
Total Annual Costs:	$ 3,334,215		
Emissions Reduction:	61.98	tpy	
Cost Effectiveness:	**$ 53,794.57**	**$/ton**	

Steam Injection

NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:	153.23	tpy	
Total Cap Investment	$ 14,018,400		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,803,254		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 2,848,666		<-- Inspection and operating costs
Total Annual Costs:	$ 4,651,921		
Emissions Reduction:	61.98	tpy	
Cost Effectiveness:	**$ 75,054.57**	**$/ton**	

** Additional NO_X emissions from the boiler are not considered in this emission reduction.

TOTAL CAPITAL INVESTEMENT COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
BLANCO C & D COMPRESSOR STATION

Blanco C & D Compressor Station							
Cost Estimation Methodology Used:	EPA Air Pollution Control Cost Manual Section 5.2, Chapter 1, Table 1.3[1]						
Unit:	T-C01		T-C02		T-D01		
Control Technology:	**Water Injection**	**Steam Injection**	**Water Injection**	**Steam Injection**	**Dry Low NO_X (DLN)**	**Water Injection**	**Steam Injection**
Control System Cost (Estimate):	$ 4,100,000	$ 5,400,000	$ 4,100,000	$ 5,400,000	$ 5,500,000	$ 4,100,000	$ 5,400,000
PEC (Control System Cost*1.18):	$ 4,838,000	$ 6,372,000	$ 4,838,000	$ 6,372,000	$ 6,490,000	$ 4,838,000	$ 6,372,000
DIC (PEC*0.85)	$ 4,112,300	$ 5,416,200	$ 4,112,300	$ 5,416,200	$ 5,516,500	$ 4,112,300	$ 5,416,200
DC (PEC + DIC):	$ 8,950,300	$ 11,788,200	$ 8,950,300	$ 11,788,200	$ 12,006,500	$ 8,950,300	$ 11,788,200
IC (PEC*0.35) :	$ 1,693,300	$ 2,230,200	$ 1,693,300	$ 2,230,200	$ 2,271,500	$ 1,693,300	$ 2,230,200
Total Capital Investment (DC+IC):	**$ 10,643,600**	**$ 14,018,400**	**$ 10,643,600**	**$ 14,018,400**	**$ 14,278,000**	**$ 10,643,600**	**$ 14,018,400**

[1] https://www.epa.gov/sites/production/files/2020-07/documents/cs5-2ch1.pdf

PEC - Purchased Equipment Cost	Control equipment
DIC - Direct Installation Cost	Foundation/supports, handling/erection, electrical, piping, installation of ductwork, painting
DC - Direct Cost	PEC and DIC
IC - Indirect Cost	Engineering, Construction and field expenses, contractor fees, start-up, performance test, contingencies

Attachment C

Cost-Effectiveness Calculations for Electrification of Combustion Units

Enterprise Field Services, LLC

Blanco C&D Compressor Station

GE 5221W Turbines	Interest Rate:	9.62%	<-- Company-specific interest rate as of 6/30/20
Unit T-CO1			
	Period:	20 years	

Base Emissions			
NO_X ppm:	51.2	ppm	<-- Average of 2016-2018 Stack Test Data
NO_X tpy:	139.23	tpy	<-- Average of 2016-2018 EI Data

Electric Conversion			
NO_X guarantee:	0	ppm	
NO_X tpy:	0.00	tpy	
Total Capital Investment:	$ 41,104,989		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 4,703,556		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ -		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$ 4,703,556		
Emissions Reduction:	139.23	tpy	
Cost Effectiveness:	**$ 33,783.60**	**$/ton**	

Enterprise Field Services, LLC

Blanco C&D Compressor Station

GE 5221W Turbines	Interest Rate:	9.62%	<-- Company-specific interest rate as of 6/30/20
Unit T-CO2			
	Period:	20	years

Base Emissions

NO_X ppm:	69.1	ppm	<-- Average of 2016-2018 Stack Test Data
NO_X tpy:	157.53	tpy	<-- Average of 2016-2018 EI Data

Electric Conversion

NO_X guarantee:	0	ppm	
NO_X tpy:	0.00	tpy	
Total Capital Investment:	$ 41,104,989		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 4,703,556		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ -		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$ 4,703,556		
Emissions Reduction:	157.53	tpy	
Cost Effectiveness:	**$ 29,857.40**	**$/ton**	

Enterprise Field Services, LLC

Blanco C&D Compressor Station

GE M5322B Turbine	Interest Rate:	9.62%	<-- Company-specific interest rate as of 6/30/20
Unit T-DO1			
	Period:	20	years

Base Emissions			
NO_X ppm:	59.0	ppm	<-- From 2016-2018 Stack Test Data
NO_X tpy:	215.21	tpy	<-- Average of 2016-2018 EI Data

Electric Conversion			
NO_X guarantee:	0	ppm	
NO_X tpy:	0.00	tpy	
Total Cap Investment:	$ 57,665,738		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 6,598,567		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ -		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$ 6,598,567		
Emissions Reduction:	215.21	tpy	
Cost Effectiveness:	**$ 30,661.21**	**$/ton**	

TOTAL CAPITAL INVESTEMENT COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
BLANCO C & D COMPRESSOR STATION

Blanco C & D Compressor Station			
Cost Estimation Methodology Used:	**EPA Air Pollution Control Cost Manual Section 5.2, Chapter 1, Table 1.3**[1]		
Unit:	**T-C01**	**T-C02**	**T-D01**
Combustion Unit:	**GE Frame 5**	**GE Frame 5**	**GE M5322B**
Electric Infrastructure Cost:	$ 6,333,333	$ 6,333,333	$ 8,333,333
Electric Motor/Compressor Cost:	$ 9,500,638	$ 9,500,638	$ 13,879,971
PEC (Control System Cost*1.18):	$ 18,684,086	$ 18,684,086	$ 26,211,699
DIC (PEC*0.85)	$ 15,881,473	$ 15,881,473	$ 22,279,944
DC (PEC + DIC):	$ 34,565,559	$ 34,565,559	$ 48,491,643
IC (PEC*0.35) :	$ 6,539,430	$ 6,539,430	$ 9,174,095
Total Capital Investment (DC+IC):	**$ 41,104,989**	**$ 41,104,989**	**$ 57,665,738**

[1] https://www.epa.gov/sites/production/files/2020-07/documents/cs5-2ch1.pdf

PEC - Purchased Equipment Cost	Control equipment
DIC - Direct Installation Cost	Foundation/supports, handling/erection, electrical, piping, installation of ductwork, painting
DC - Direct Cost	PEC and DIC
IC - Indirect Cost	Engineering, Construction and field expenses, contractor fees, start-up, performance test, contingencies

NMED Final Cost Evaluation
Enterprise Field Services - Chaco Gas Plant

Facility Information

Enterprise - Chaco Gas Plant	**Facility**
Two 1970s GE CTs, 19,500 HP each	**Units**
17 and 18	**Unit IDs**
Water/Steam Injection	**Evaluated Pollution Control**
42.0	**Post-control Emissions Rate (ppmvd)***

*Source (A), Table S-1

Supporting Information

1999	**Calendar year associated with cost estimates (based on primary data source)***
19,500	**Nameplate Capacity (hp/unit)**

*Source (A), Table A-4

Economic Evaluation

Cost Component		Unit 17	Unit 18	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 431,000	$ 431,000	(A)	Total system cost
Other Direct Capital Costs 1 ($)	ODC	$ 243,975	$ 243,975	(A)	Taxes Freight and installation direct costs
Indirect Capital Costs ($)	IDC	$ 408,200	$ 408,200	(A)	Indirect installation and contingency
Total Capital Costs - Direct ($)	TCC	$ 1,083,175	$ 1,083,175	-	PEC + ODC + IDC
Additional Capital ($)	AC	$ -	$ -	-	Not specified by Enterprise
Total Capital Investment ($)	TCI	$ 1,083,175	$ 1,083,175	(A)	TCC + AC
Interest Rate (%)	R	10.50%	10.50%	Enterprise August 2023 FFA update	
Useful Life (yr)	Y	15	15	Enterprise initial (2019) FFA and August 2023 update	
Capital Recovery Factor	CRF	0.1352	0.1352	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 146,497	$ 146,497	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 294,000	$ 294,000	(A)	Annual costs (does not include Capital Recovery)
Other Indirect Annual Costs ($/yr)	OAC	$ 43,327	$ 43,327	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 483,824	$ 483,824	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	-29%	-22%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate; Negative control efficiency and cost effectiveness due to current emissions rate being less than assumed post-control rate of 42 ppm.
Baseline Actual NOx Emissions (ton/yr)	BAE	75.3	80.9	CY 2022 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	75.3	80.9	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	-21.5	-18.1	-	PAE x Eff
1999$ Cost Effectiveness ($/ton)	**CE1**	**-$22,481**	**-$26,767**	-	TAC/ER
Price Index	PI	2.04	2.04	-	CEPCI 2024* / CEPCI 1999 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**-$45,860**	**-$54,605**	-	CE1 x PI

(A) Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, Nov 1999, Table A-4, 25 MW Class
Note: Units 17 and are ~ 14.5 MW (mechanical) units and thus reasonably similiar in size to the 25 MW Class used in the analysis.

NMED Final Cost Evaluation
Enterprise Field Services - Chaco Gas Plant

Facility Information

Enterprise - Chaco Gas Plant	**Facility**
Two 1970s GE CTs, 19,500 HP each	**Units**
17 and 18	**Unit IDs**
SCR	**Evaluated Pollution Control**

Supporting Information

2024	**Calendar year associated with cost estimates**
175.5	**Heat Input Capacity (MMBtu/hr (U17), calculated)**
178.5	**Heat Input Capacity (MMBtu/hr (U18), calculated)**

Economic Evaluation

Cost Component		Unit 17	Unit 18	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	A retrofit factor of 1.1 was used in the EPA SCR Tool to account for the additional capital costs anticipated to create physical space for the SCR system. This factor was selected based on Enterprise's recurring assertion that the current layout of the existing building can not accommodate the physical space needed for SCR. Aerial photos provided by Enterprise suggest there is space for SCR if building modifications are made.
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	$ -	-	
Total Capital Costs - Direct ($)	TCC	$8,163,254	$ 8,253,687	EPA SCR Tool (2024$)	
Additional Capital ($)	AC	$ -	$ -	See Note	
Total Capital Investment ($)	TCI	$ 8,163,254	$ 8,253,687	-	TCC + AC
Interest Rate (%)	R	10.50%	10.50%	Enterprise August 2023 FFA update	
Useful Life (yr)	Y	20	20	Default per EPA Cost Manual	
Capital Recovery Factor	CRF	0.1215	0.1215	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 991,780	$ 1,002,767	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 157,765	$ 160,838	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 3,118	$ 3,123	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 1,152,663	$ 1,166,729	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	80%	80%	EPA SCR Tool	Consistent with EPA and industry documentation
Baseline Actual NOx Emissions (ton/yr)	BAE	75.3	80.9	CY 2022 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	75.3	80.9	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	60.3	64.8	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 19,128**	**$ 18,017**	-	TAC/ER

NMED Final Cost Evaluation
Enterprise Field Services - Chaco Gas Plant

Facility Information

Enterprise - Chaco Gas Plant	**Facility**
Two 1970s GE CTs, 19,500 HP each	**Units**
17 and 18	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
9.0	**Post-control Emissions Rate (ppmvd @ 15% O2)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired CT >15,900 hp

Supporting Information

2020	**Calendar year associated with cost estimates (year not specified in submission)**
19,500	**Nameplate Capacity (hp/unit)**

Economic Evaluation

Cost Component		Unit 17	Unit 18	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 47,151,000	$ 47,151,000	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $2418/hp cost metric as Enterprise did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered CT.
Interest Rate (%)	R	10.50%	10.50%	Enterprise August 2023 FFA update	
Useful Life (yr)	Y	30	30	ERG experience based on discussions with CT manufacturers	
Capital Recovery Factor	CRF	0.1105	0.1105	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 5,211,528	$ 5,211,528	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 107,343	$ 107,343	Enterprise August 2023 FFA update (2023$ converted to 2020$ using CEPCI)	Incremental inspection and overhaul costs of a CT equipped with SoloNOx compared to existing CT
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 5,318,871	$ 5,318,871	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	72%	74%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	75.3	80.9	CY 2022 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	75.3	80.9	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	54.6	59.7	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 97,463**	**$ 89,053**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 so assumed costs are in 2020$
Price Index	PI	1.34	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 130,600**	**$ 119,332**	-	CE1 x PI

NMED Final Cost Evaluation
Enterprise Field Services - Chaco Gas Plant

Facility Information

Enterprise - Chaco Gas Plant	**Facility**
Two 1970s GE CTs, 19,500 HP each	**Units**
17 and 18	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (lb/hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
19,500	**Nameplate Capacity (hp/unit)**

Economic Evaluation

Cost Component		Unit 17	Unit 18	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Enterprise provided a cost estimate for electrification using EPA Cost Control Manual Section 5.2, which pertains to acid gas scrubbers. As this is not applicable to replacement with EMD, a Total Capital Cost metric of $2,084 (2023$/hp) was calculated using detailed cost information provided by other facilities. The TCI figure assumes no costs associated with substation or distribution line upgrades. This assumption underestimates costs given that Enterprise indicated in its August 2023 update that utility infrastructure upgrades would be needed to support electrification at all three of its facilities.
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ 40,638,000	$ 40,638,000	See Note	
Additional Capital ($)	AC	$ -	$ -	-	
Total Capital Investment ($)	TCI	$ 40,638,000	$ 40,638,000	See Note	
Interest Rate (%)	R	10.50%	10.50%	Enterprise Aug 2023 CBI update	
Useful Life (yr)	Y	25	25	Consistent with other FFAs	
Capital Recovery Factor	CRF	0.114	0.114	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 4,650,179	$ 4,650,179	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 3,942,706	$ 3,963,753	-	AED + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 7,885,412	$ 7,927,505	ERG calculation	Assumes unit at 60% load, 95% efficiency and a $0.10/kWh price
Associated non-electricity O&M ($/yr)	AOM	$ -	$ -	Engineering judgement	Assumed to be negligible
Annual Fuel Credit ($/yr)	AFC	$ (3,942,706)	$ (3,963,753)	ERG calculation	Assumed equal to 50% of AED
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 8,592,884	$ 8,613,931	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	100%	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	75.3	80.9	CY 2022 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	75.3	80.9	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	75.3	80.9	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 114,075**	**$ 106,416**	-	TAC/ER
Price Index	PI	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 114,075**	**$ 106,416**	-	CE1 x PI

NMED Final Cost Evaluation
Enterprise Field Services - Chaco Gas Plant

Facility Information

Enterprise - Chaco Gas Plant	**Facility**
Three 1996 Solar Mars CTs, 15,000 hp each	**Units**
Units 35, 36 and 37	**Unit IDs**
SoloNOx	**Evaluated Pollution Control**
9.0	**Post-control Emissions Rate (ppmv)***

*Per September 9, 2024 letter from Solar Turbines

Supporting Information

2019	**Calendar year associated with cost estimates (year not specified in submission)**
15,000	**Maximum Power Output (hp)**

Economic Evaluation

Cost Component		Unit 35	Unit 36	Unit 37	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 1,568,700	$ 1,568,700	$ 1,568,700	Enterprise Aug 2023 FFA update	Includes costs related to the following: base SoloNOx retrofit, requisite uprating to 16,000 HP, control upgrades, and other related costs (per 9/19/19 email from CT manufacturer)
Other Direct Capital Costs 1 ($)	ODC1	$ 501,010	$ 501,010	$ 501,010	Enterprise Aug 2023 FFA update	
Other Direct Capital Costs 2 ($)	ODC2	$ 1,165,005	$ 1,165,005	$ 1,165,005	Enterprise Aug 2023 FFA update	
Indirect Capital Costs ($)	IDC	$ 297,994	$ 297,994	$ 297,994	Enterprise Aug 2023 FFA update	
Total Capital Costs - Direct ($)	TCC	$ 3,532,710	$ 3,532,710	$ 3,532,710	-	PEC + ODC1 + ODC2 + IDC
Additional Capital ($)	AC	$ 529,906	$ 529,906	$ 529,906	-	Estimated installation costs = 15% of TCC
Total Capital Investment ($)	TCI	$ 4,062,616	$ 4,062,616	$ 4,062,616	-	TCC + AC
Interest Rate (%)	R	10.50%	10.50%	10.50%	Enterprise Aug 2023 FFA update	-
Useful Life (yr)	Y	20	20	20	Enterprise initial (2019) FFA and August 2023 update	Consistent with other FFAs
Capital Recovery Factor	CRF	0.1215	0.1215	0.1215	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 493,581	$ 493,581	$ 493,581	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 109,801	$ 109,801	$ 109,801	Enterprise August 2023 FFA update (2023$ converted to 2019$ using CEPCI)	Incremental inspection and overhaul costs per Enterprise. Reasonably consistent with other facilities.
Other Indirect Annual Costs ($/yr)	OAC	$ 162,505	$ 162,505	$ 162,505	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 765,886	$ 765,886	$ 765,886	-	ACC + OMC
NOx Control Efficiency (%)	Eff	92%	93%	93%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	98.0	92.5	82.2	CY 2022 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	98.0	92.5	82.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	90.4	86.1	76.1	-	PAE x Eff
2019$ Cost Effectiveness ($/ton)	**CE1**	**$ 8,472**	**$ 8,896**	**$ 10,065**	-	TAC/ER
Price Index	PI	1.31	1.31	1.31	-	CEPCI 2024* / CEPCI 2019 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 11,098**	**$ 11,654**	**$ 13,185**	-	CE1 x PI

NMED Final Cost Evaluation
Enterprise Field Services - Chaco Gas Plant

Facility Information

Enterprise - Chaco Gas Plant	**Facility**
Three 1996 Solar Mars CTs, 15,000 hp each	**Units**
Units 35, 36 and 37	**Unit IDs**
SCR	**Evaluated Pollution Control**

Supporting Information

2024	**Calendar year associated with cost estimates**
115.8	**Heat Input Capacity (MMBtu/hr, calculated)**

Economic Evaluation

Cost Component		Unit 35	Unit 36	Unit 37	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	A retrofit factor of 1.1 was used in the EPA SCR Tool to account for the additional capital costs anticipated to create physical space for the SCR system. This factor was selected based on Enterprise's recurring assertion that the current layout of the existing building can not accommodate the physical space needed for SCR. Aerial photos provided by Enterprise suggest there is space for SCR if building modifications are made.
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	
Total Capital Costs - Direct ($)	TCC	$6,230,081	$ 6,230,081	$ 6,230,081	EPA SCR Tool (2024$)	
Additional Capital ($)	AC	$ -	$ -	$ -	See Note	
Total Capital Investment ($)	TCI	$ 6,230,081	$ 6,230,081	$ 6,230,081	-	TCC + AC
Interest Rate (%)	R	10.50%	10.50%	10.50%	Enterprise August 2023 FFA update	
Useful Life (yr)	Y	20	20	20	Default per EPA Cost Manual	
Capital Recovery Factor	CRF	0.1215	0.1215	0.1215	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 756,913	$ 756,913	$ 756,913	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 108,554	$ 98,573	$ 92,942	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 3,002	$ 3,002	$ 3,002	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 868,469	$ 858,488	$ 852,857	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	80%	80%	80%	EPA SCR Tool	Consistent with EPA and industry documentation
Baseline Actual NOx Emissions (ton/yr)	BAE	98.0	92.5	82.2	CY 2022 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	98.0	92.5	82.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	78.4	74.0	65.7	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 11,072**	**$ 11,601**	**$ 12,976**	-	TAC/ER

NMED Final Cost Evaluation
Enterprise Field Services - Chaco Gas Plant

Facility Information

Enterprise - Chaco Gas Plant	**Facility**
Three 1996 Solar Mars CTs, 15,000 hp each	**Units**
Units 35, 36 and 37	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
15.0	**Post-control Emissions Rate (ppmvd @ 15% O2)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired CT >=4,000 hp and <15,900 hp

Supporting Information

2020	**Calendar year associated with cost estimates (year not specified in submission)**
15,000	**Nameplate Capacity (hp/unit)**

Economic Evaluation

Cost Component		Unit 35	Unit 36	Unit 37	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 36,270,000	$ 36,270,000	$ 36,270,000	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $2418/hp cost metric as Enterprise did not provide a cost evaluation for replacement with an equivalent fossil fuel powered CT.
Interest Rate (%)	R	10.50%	10.50%	10.50%	Enterprise August 2023 FFA update	
Useful Life (yr)	Y	30	30	30	ERG experience based on discussions with CT manufacturers	
Capital Recovery Factor	CRF	0.1105	0.1105	0.1105	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 4,008,868	$ 4,008,868	$ 4,008,868	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 107,343	$ 107,343	$ 107,343	Enterprise August 2023 FFA update (2023$ converted to 2020$ using CEPCI)	Incremental inspection and overhaul costs of a CT equipped with SoloNOx compared to existing CT
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 4,116,211	$ 4,116,211	$ 4,116,211	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	87%	88%	88%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	98.0	92.5	82.2	CY 2022 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	98.0	92.5	82.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	85.3	81.8	72.1	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 48,249**	**$ 50,305**	**$ 57,126**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 so assumed costs are in 2020$
Price Index	PI	1.34	1.34	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 64,653**	**$ 67,409**	**$ 76,549**	-	CE1 x PI

NMED Final Cost Evaluation
Enterprise Field Services - Chaco Gas Plant

Facility Information

Enterprise - Chaco Gas Plant	**Facility**
Three 1996 Solar Mars CTs, 15,000 hp each	**Units**
Units 35, 36 and 37	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (lb/hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
15,000	**Nameplate Capacity (hp/unit)**

Economic Evaluation

Cost Component		Unit 35	Unit 36	Unit 37	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	Included in TCC	Enterprise provided a cost estimate for electrification using EPA Cost Control Manual Section 5.2, which pertains to acid gas scrubbers. As this is not applicable to replacement with EMD, a Total Capital Cost metric of $2,084 (2023$/hp) was calculated using detailed cost information provided by other facilities. The TCI figure assumes no costs associated with substation or distribution line upgrades. This assumption underestimates costs given that Enterprise indicated in its August 2023 update that utility infrastructure upgrades would be needed to support electrification at all three of its facilities.
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	Included in TCC	
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	Included in TCC	
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	Included in TCC	
Total Capital Costs - Direct ($)	TCC	$ 31,260,000	$ 31,260,000	$ 31,260,000	See Note	
Additional Capital ($)	AC	$ -	$ -	$ -	-	
Total Capital Investment ($)	TCI	$ 31,260,000	$ 31,260,000	$ 31,260,000	See Note	
Interest Rate (%)	R	10.50%	10.50%	10.50%	Enterprise Aug 2023 FFA update	
Useful Life (yr)	Y	25	25	25	Consistent with other FFAs	
Capital Recovery Factor	CRF	0.114	0.114	0.114	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 3,577,061	$ 3,577,061	$ 3,577,061	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 2,642,058	$ 2,164,076	$ 1,955,728	-	AED + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 5,284,116	$ 4,328,153	$ 3,911,456	ERG calculation	Assumes unit at 60% load, 95% efficiency and a $0.10/kWh price
Associated non-electricity O&M ($/yr)	AOM	$ -	$ -	$ -	Engineering judgement	Assumed to be negligible
Annual Fuel Credit ($/yr)	AFC	$ (2,642,058)	$ (2,164,076)	$ (1,955,728)	ERG calculation	Assumed equal to 50% of AED
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 6,219,119	$ 5,741,137	$ 5,532,789	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	100%	100%	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	98.0	92.5	82.2	CY 2022 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	98.0	92.5	82.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	98.0	92.5	82.2	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 63,431**	**$ 62,068**	**$ 67,345**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 63,431**	**$ 62,068**	**$ 67,345**	-	CE1 x PI

NMED Final Cost Evaluation
Enterprise Field Services - Chaco Gas Plant

Facility Information

Enterprise - Chaco Gas Plant	**Facility**
Three 3,400 hp Clark 2SLB RICE*	**Units**
Units 12, 13 and 14	**Unit IDs**
LEC	**Evaluated Pollution Control**
0.5	**Post-control Emissions Rate (g NOx/bhp-hr)****

*Constructed in 1966 and reconstructed in 1996, at which time they were retrofitted with LEC.

Supporting Information

2021	**Calendar year associated with cost estimates**
3400	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 12	Unit 13	Unit 14	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 5,185,000	$ 5,185,000	$ 5,185,000	8/28/23 info from DCP	All-in estimate ($/HP) x Maximum Power Output (HP); Enterprise did not provide cost estimates for LEC, so a Total Capital Investment metric of $1,525/hp (2021$) was calculated using a vendor cost estimate provided by DCP to retrofit similar 1970s-vintage Clark TLA series 2SLB engines with LEC controls capable of achieving 0.5 g/hp-hr.
Interest Rate (%)	R	10.50%	10.50%	10.50%	Enterprise Aug 2023 FFA update	
Useful Life (yr)	Y	20	20	20	Consistent with other FFAs	
Capital Recovery Factor	CRF	0.1215	0.1215	0.1215	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 629,943	$ 629,943	$ 629,943	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	$ -	-	Incremental O&M of a LEC retrofit is expected to be negligible
Other Indirect Annual Costs ($/yr)	OAC	$ 207,400	$ 207,400	$ 207,400	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 837,343	$ 837,343	$ 837,343	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	87%	76%	90%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	88.7	41.8	131.2	CY 2022 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	88.7	41.8	131.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	77.1	31.9	118.3	-	PAE x Eff
2021$ Cost Effectiveness ($/ton)	**CE1**	**$ 10,862**	**$ 26,275**	**$ 7,078**	-	TAC/ER; Vendor estimate provided in July 2021 so assumed in 2021$
Price Index	PI	1.13	1.13	1.13	-	CEPCI 2024* / CEPCI 2021 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 12,274**	**$ 29,691**	**$ 7,998**	-	CE1 x PI

NMED Final Cost Evaluation
Enterprise Field Services - Chaco Gas Plant

Facility Information

Enterprise - Chaco Gas Plant	**Facility**
Three 3,400 hp Clark 2SLB RICE*	**Units**
Units 12, 13 and 14	**Unit IDs**
Replacement with new RICE	**Evaluated Pollution Control**
0.3	**Post-control Emissions Rate (g NOx/bhp-hr)****

*Constructed in 1966 and reconstructed in 1996, at which time they were retrofitted with LEC.

**Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired spark ignited RICE >=1875 bhp

Supporting Information

2020	**Calendar year associated with cost estimates**
3,400	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 12	Unit 13	Unit 14	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 10,971,800	$ 10,971,800	$ 10,971,800	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $3227/hp cost metric as Enterprise did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered RICE.
Interest Rate (%)	R	10.50%	10.50%	10.50%	Enterprise Aug 2023 FFA update	-
Useful Life (yr)	Y	30	30	30	ERG experience based on discussions with RICE manufacturers	
Capital Recovery Factor	CRF	0.1105	0.1105	0.1105	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 1,212,696	$ 1,212,696	$ 1,212,696	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	$ -	-	Incremental O&M reasonably negligible
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 1,212,696	$ 1,212,696	$ 1,212,696	-	ACC + OMC
NOx Control Efficiency (%)	Eff	92%	86%	94%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	88.7	41.8	131.2	CY 2022 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	88.7	41.8	131.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	81.7	35.8	123.5	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 14,837**	**$ 33,845**	**$ 9,822**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 and thus assumed costs are in 2020$
Price Index	PI	1.34	1.34	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 19,882**	**$ 45,353**	**$ 13,162**	-	CE1 x PI

NMED Final Cost Evaluation
Enterprise Field Services - Chaco Gas Plant

Facility Information

Enterprise - Chaco Gas Plant	**Facility**
Three 3,400 hp Clark 2SLB RICE*	**Units**
Units 12, 13 and 14	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (lb/hr)**

*Constructed in 1966 and reconstructed in 1996, at which time they were retrofitted with LEC.

Supporting Information

2023	**Calendar year associated with cost estimates**
3,400	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 12	Unit 13	Unit 14	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	Enterprise provided a cost estimate for electrification using EPA Cost Control Manual Section 5.2, which pertains to acid gas scrubbers. As this is not applicable to replacement with EMD, a Total Capital Cost metric of $2,084 (2023$/hp) was calculated using detailed cost information provided by other facilities. The TCI figure assumes no costs associated with substation or distribution line upgrades. This assumption underestimates costs given that Enterprise indicated in its August 2023 update that utility infrastructure upgrades would be needed to support electrification at all three of its facilities.
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ 7,085,600	$ 7,085,600	$ 7,085,600	See Note	
Additional Capital ($)	AC	$ -	$ -	$ -	-	
Total Capital Investment ($)	TCI	$ 7,085,600	$ 7,085,600	$ 7,085,600	See Note	
Interest Rate (%)	R	10.50%	10.50%	10.50%	Enterprise Aug 2023 FFA update	
Useful Life (yr)	Y	25	25	25	Consistent with other FFAs	
Capital Recovery Factor	CRF	0.114	0.114	0.114	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 810,800	$ 810,800	$ 810,800	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 496,209	$ 423,269	$ 550,640	-	AED + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 992,417	$ 846,537	$ 1,101,280	ERG calculation	Assumes unit at 60% load, 95% efficiency and a $0.10/kWh price
Associated non-electricity O&M ($/yr)	AOM	$ -	$ -	$ -	Engineering judgement	Assumed to be negligible
Annual Fuel Credit ($/yr)	AFC	$ (496,209)	$ (423,269)	$ (550,640)	ERG calculation	Assumed equal to 50% of AED
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 1,307,009	$ 1,234,069	$ 1,361,441	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	100%	100%	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	88.7	41.8	131.2	CY 2022 emissions testing and average operating hours (CY 2016 - 2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	88.7	41.8	131.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	88.7	41.8	131.2	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 14,735**	**$ 29,541**	**$ 10,377**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 14,735**	**$ 29,541**	**$ 10,377**	-	CE1 x PI

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Enterprise Field Services - Chaco Gas Plant

Unit 17: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.1

* NOTE: You must document why a retrofit factor of 1.1 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	175.5	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	1,461,535,403	scf/Year
	8586	hr/yr
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW
Plant Elevation	6020	Feet above sea level

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365	days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.10	lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.02	lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050		Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
			Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours		
Estimated SCR equipment life	20	Years*	Gas temperature at the SCR inlet (T)	650 °F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour		

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

* For industrial boilers, the typical equipment life is between 20 and 25 years.

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	10.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 17: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	176	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,491,154,219	scf/Year
Actual Annual fuel consumption (Mactual) =		1,461,535,403	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.980	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8586	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	14.04	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	60.27	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.25	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.8	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.10	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3007	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	638.74	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	5	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	19	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	900	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.1215

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	103.90	kW

Unit 17: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$8,163,254	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$157,765 in 2024 dollars
Indirect Annual Costs (IDAC) =	$994,953 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$1,152,718 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$40,816 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$11,416 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$89,207 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$16,326 in 2024 dollars
Direct Annual Cost =		$157,765 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,118 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$991,835 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$994,953 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,152,718 per year in 2024 dollars
NOx Removed =	60 tons/year
Cost Effectiveness =	$19,125 per ton of NOx removed in 2024 dollars

Unit 18: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.1

* NOTE: You must document why a retrofit factor of 1.1 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	178.5	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	1,486,518,914	scf/Year
	8632	hr/yr
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW
Plant Elevation	6020	Feet above sea level

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365	days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.11	lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.02	lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050		Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
			Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours		
Estimated SCR equipment life	20	Years*	Gas temperature at the SCR inlet (T)	650 °F
Concentration of reagent as stored (C_{stored})	29	percent*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK ft^3/min-MMBtu/hour
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*		
Number of days reagent is stored ($t_{storage}$)	14	days		

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

* For industrial boilers, the typical equipment life is between 20 and 25 years.

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	10.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 18: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	179	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,516,644,035	scf/Year
Actual Annual fuel consumption (Mactual) =		1,486,518,914	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.980	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8586	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	15.01	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	64.43	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.25	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.8	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.10	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3007	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	650.85	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	6	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	20	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,000	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.1215

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	105.67	kW

Unit 18: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$8,253,687	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$160,838 in 2024 dollars
Indirect Annual Costs (IDAC) =	$1,005,946 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$1,166,785 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$41,268 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$12,203 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$90,732 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$16,636 in 2024 dollars
Direct Annual Cost =		$160,838 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,123 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,002,823 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,005,946 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,166,785 per year in 2024 dollars
NOx Removed =	64 tons/year
Cost Effectiveness =	$18,110 per ton of NOx removed in 2024 dollars

Unit 35: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.1

* NOTE: You must document why a retrofit factor of 1.1 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	115.8	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	840,139,670	scf/Year
	7480	hr/yr
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	6020	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.23	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.05	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	10.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 35: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	116	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	983,906,887	scf/Year
Actual Annual fuel consumption (Mactual) =		840,139,670	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.854	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7480	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	20.98	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	78.45	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.25	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.8	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.10	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3007	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	440.78	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	8	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	28	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,300	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.1215

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	68.55	kW

Unit 35: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$6,230,081	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$108,554 in 2024 dollars
Indirect Annual Costs (IDAC) =	$759,957 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$868,511 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$31,150 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$14,859 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$51,279 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$11,266 in 2024 dollars
Direct Annual Cost =		$108,554 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,002 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$756,955 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$759,957 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$868,511 per year in 2024 dollars
NOx Removed =	78 tons/year
Cost Effectiveness =	$11,071 per ton of NOx removed in 2024 dollars

NMED Final Cost Evaluation
Enterprise Field Services - Chaco Gas Plant

Unit 36: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.1

* NOTE: You must document why a retrofit factor of 1.1 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	115.8	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	688,173,230	scf/Year
	6127	hr/yr
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	6020	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.26	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.05	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	10.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 36: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	116	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	983,906,887	scf/Year
Actual Annual fuel consumption (Mactual) =		688,173,230	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.699	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6127	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	24.16	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	74.01	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.25	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.8	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.10	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3007	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	446.04	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	9	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	32	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,500	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.1215

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	68.55	kW

Unit 36: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$6,230,081	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$98,573 in 2024 dollars
Indirect Annual Costs (IDAC) =	$759,957 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$858,529 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$31,150 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$14,018 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$42,004 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$11,400 in 2024 dollars
Direct Annual Cost =		$98,573 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,002 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$756,955 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$759,957 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$858,529 per year in 2024 dollars
NOx Removed =	74 tons/year
Cost Effectiveness =	$11,600 per ton of NOx removed in 2024 dollars

Unit 37: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.1

* NOTE: You must document why a retrofit factor of 1.1 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	115.8	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	621,905,529	scf/Year
	5537	hr/yr
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	6020	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.26	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.05	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	10.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 37: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	116	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	983,906,887	scf/Year
Actual Annual fuel consumption (Mactual) =		621,905,529	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.632	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5537	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	23.74	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	65.74	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.25	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.8	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.10	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3007	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	445.35	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	9	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	32	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,500	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.1215

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	68.55	kW

Unit 37: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$6,230,081	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$92,942 in 2024 dollars
Indirect Annual Costs (IDAC) =	$759,957 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$852,899 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$31,150 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$12,450 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$37,959 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$11,383 in 2024 dollars
Direct Annual Cost =		$92,942 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,002 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$756,955 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$759,957 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$852,899 per year in 2024 dollars
NOx Removed =	66 tons/year
Cost Effectiveness =	$12,975 per ton of NOx removed in 2024 dollars

Enterprise Products

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS HOLDINGS LLC
(General Partner)

ENTERPRISE PRODUCTS OPERATING LLC

November 14, 2019

Federal Express

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

Re: Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program
Enterprise Field Services, LLC
Blanco C&D Compressor Station and Chaco Gas Plant

Mr. Singleton:

Enterprise Field Services, LLC is submitting an analysis of control measures for the Blanco C&D Compressor Station and the Chaco Gas Plant in San Juan County, New Mexico, as requested by the NMED by letter dated July 18, 2019 and extended by the NMED letter dated October 29, 2019.

In addition, Enterprise has included legal comments, which are integral to Enterprise's position on the appropriateness of the control measures analyzed for all three facilities. For convenience and to avoid duplication, the legal comments are for the South Carlsbad Compressor Station, Blanco C&D Compressor Station and the Chaco Gas Plant.

If you have questions or require additional information, please contact me at (713) 381-6698 or by email at rmhavalda@eprod.com or Bradley Cooley at (713) 381-5828.

Thank you,

Robert Havalda, P.E.
Senior Engineer, Environmental

Bradley J. Cooley, P.E.
Senior Manager, Environmental

/kna
Attachment

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Michelle Lujan Grisham
Governor

Howie C. Morales
Lt. Governor

James C. Kenney
Cabinet Secretary

Jennifer J. Pruett
Deputy Secretary

October 29, 2019

Robert Havalda, P.E.
Senior Engineer, Environmental
Enterprise Products Partners, L.P.
P.O. Box 4324
Houston, TX 77210-4324

Re: Request for Two-Week Extension for Submittal of the Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program
Enterprise Products Partners, L.P.

Mr. Havalda:

The New Mexico Environment Department Air Quality Bureau (AQB) has received and reviewed your written request to extend the submittal deadline for the Blanco C & D Compressor Station and Chaco Gas Plant four-factor analyses from November 1, 2019 to November 15, 2019.

This letter grants the requested extension. Should you have any additional questions or concerns as these reports are finalized, please do not hesitate to contact Mark Jones at 505.566.9746 (mark.jones@state.nm.us) or me at 505.476.4350 (kerwin.singleton@state.nm.us).

Sincerely,

Kerwin C. Singleton
Planning Section Chief

RECEIVED
NOV 06 2019
ENVIRONMENTAL DEPARTMENT

REGIONAL HAZE FOUR-FACTOR ANALYSIS

Enterprise Field Services, LLC, Chaco Gas Plant

Prepared By:

Adam Erenstein – Manager of Consulting Services
Jake Zenker - Consultant

TRINITY CONSULTANTS
9400 Holly Ave.
Building 3, Suite 300
Albuquerque, NM 87122
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November 2019

Project 193201.0181

Trinity Consultants

Environmental solutions delivered uncommonly well

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1. EXECUTIVE SUMMARY

In the 1977 amendments to the Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977. EPA has since amended the RHR in certain respects, most recently on January 10, 2017.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, the states, among other things:

(A) *"[E]valuate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment" and "include in [the state's] implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy."* 40 CFR 51. 308(f)(2)(i). This is known as a four-factor analysis.

(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the state must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the state must consider the uniform rate of improvement in visibility. 40 CFR 51. 308(f)(1). The uniform rate of progress or improvement is sometimes referred to as the "URP" or the glidepath and is considered in the process of developing the state's Long Term Strategy (LTS).

The second implementation, or planning, period (2019-2028) for national regional haze efforts is currently underway. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural or biogenic and manmade or anthropogenic sources of emissions. Using a Photochemical Grid Model (PGM), the Western Regional Air Partnership (WRAP), in coordination with the EPA, is tasked with comparing anthropogenic source contributions against natural background concentrations. EPA has issued guidance to states for development of State Implementation Plans (SIPs) for regional haze requirements for the second planning period.[1,2]

[1] U.S. EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, EPA-457/B-19-003 (Aug. 2019); U.S. EPA, Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program, EPA-454/R-18-010 (Dec. 2018).

[2] U.S. EPA, Technical Support Document for EPA's 2028 Regional Haze Modeling (Sept. 2019).

Pursuant to 40 CFR 51.308(f)(2), the states are responsible for identifying sources that contribute to the most impaired days in the Class I areas. To accomplish this, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for Title V sources and screened each facility's potential impact on visibility in Class I areas using a "Q/d" analysis, where "Q" is the magnitude of emissions that could impact ambient visibility and "d" is the distance of a facility to a Class I area. The NMED defined a source with a high potential for visibility impairment as one with a "Q/d" greater than 5.5. From this analysis, 24 facilities were identified by the NMED. On July 18, 2019, the NMED informed Enterprise Field Services, LLC (Enterprise) that its facility, the Chaco Gas Plant, was identified as one of the sources potentially contributing to regional haze at the Mesa Verde Class I area.

In coordination with guidance provided by WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. The NMED's July 18, 2019 notification letter to Enterprise specifies that any equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The equipment at the facility that is subject to this analysis, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant are reported in Table 1.

Table 1. Summary of Equipment and Applicability to a Four-Factor Analysis

Equipment	Unit No.	NO_X Hourly PTE (lb/hr)	NO_X Annual PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
General Electric (GE) Frame 5 Turbines	17	78.5	344.0	Yes	2.1	9.1	No
	18	78.5	344.0	Yes	2.1	9.1	No
Solar Mars T-15000 Turbines	35	76.2	333.6	Yes	1.4	6.3	No
	36	76.2	333.6	Yes	1.4	6.3	No
	37	76.2	333.6	Yes	1.4	6.3	No
Clark TLA-10 2SLB SI-RICE Engines	12	49.7	218.0	Yes	< 1.0	1.9	No
	13	49.7	218.0	Yes	< 1.0	1.9	No
	14	49.7	218.0	Yes	< 1.0	1.9	No

*All emission rates reported in this table are on a per unit basis.

Once the applicability of process equipment and pollutants has been determined, potential retrofit control technologies must be identified. One of the reference sources that the NMED has suggested consulting is the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC).[3] In order to determine the most relevant and current retrofit controls available, the RBLC was queried for the previous ten years. Summaries of the results of this search are provided and discussed in Section 2 of this report. The facility engineers then reviewed the list of available retrofit technologies and performed a technical feasibility assessment for each control option. The

[3] See NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

four-factor analysis was then conducted for those controls that are technically feasible at the Chaco Gas Plant site.

Based on the technical and economic factors summarized in this report, Enterprise has provided recommendations for the NMED in its efforts to design, in coordination with WRAP, the SIP under the RHR.

2.1. COMBUSTION TURBINES

Five of Chaco's natural gas-fired turbines (Units 17, 18, 35, 36, and 37) are subject to this four-factor analysis due to their NO_X emission rates. The only pollutant subject to evaluation for these units is NO_X.

2.1.1. Combustion Turbine Background

A gas turbine is an internal combustion engine that operates with a rotary, rather than reciprocating, motion and is composed of three primary components: a compressor, a combustor, and a power turbine. The compressor draws in ambient air and compresses it up to 30 times the ambient pressure, then directs it into the combustor, where fuel is introduced, ignited, and burned. Exhaust gas from the combustor is then diluted with additional air and sent to the power turbine at temperatures of up to 2600 °F. The hot exhaust gas expands in the power turbine section, generating energy in the form of shaft horsepower.[4]

The treatment of the exhaust gases exiting the turbine dictates the cycle designation of these units. The heat content can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).[5] The units at Chaco are regenerative cycle turbines, which are essentially simple cycle gas turbines with an added heat exchanger.

NO_x is formed via three fundamentally different mechanisms. The principal NO_x formation mechanism, thermal NO_x, arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion. Most thermal NO_x forms in the highest temperature regions of the combustion chamber. The second NO_x formation mechanism, fuel NO_x, arises from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. The final NO_x formation mechanism, prompt NO_x, arises from early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The significance of prompt NO_x is negligible in comparison to thermal and fuel NO_x. Fuel NO_x will also be negligible for Chaco's turbines assessed here, as these combustion turbines fire natural gas, which contains a negligible amount of nitrogen compounds. Therefore, this analysis will focus on thermal NO_x.

The PTE from each turbine is reported in the facility's New Source Review (1555-M7) and Title V (116-R2-M1) permits and is summarized in Table 1.

2.1.2. Potential NO_X Controls for a Combustion Turbine

There are three general methods of controlling NO_X emissions from gas turbines: (1) wet controls, which use steam or water injection to reduce combustion temperatures and NO_X formation, (2) dry controls that use

[4] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines."

[5] Ibid.

advanced combustor design to suppress NO_X formation, and (3) post-combustion, catalytic controls to selectively reduce NO_X.[6]

The categories of retrofit control equipment identified for combustion turbines during a comprehensive review of the RBLC are reported in Table 2. A detailed discussion, including a description, the technical feasibility, and the anticipated performance of each control, is provided below.

Table 2. Potential Control Options for Combustion Turbines

Control Equipment	Technically Feasible	NO_X Control Efficiency
Good Combustion Practices and Fuel Selection	**Base Case**	**N/A**
SoloNOx	**Mars T-15000 Only**	**91%**
Dry Low NOx	**No**	**N/A**
Water/Steam Injection	**GE Only**	**15%**
Selective Catalytic Reduction	**No**	**N/A**

2.1.2.1. Good Combustion Practices and Fuel Selection

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. Applying concepts from engineering knowledge, experience, and the manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for the equipment involved, and using pipeline quality natural gas. If good combustion practices are maintained, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from combustion turbines; therefore, it has been determined that this method of NO_X control is feasible for the units at Chaco. However, these practices are currently in use at Chaco, as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices has been included in this report.

2.1.2.2. Dry Low NO_X Combustor or SoloNOx

The key factors in thermal NO_X formation are the combustion temperature and the residence time of fuel in the combustor. Dry low NO_X burners (or SoloNOx for Solar Turbines) reduce NO_X emissions by reducing both of these factors. Ultimately, this is accomplished by optimizing the air-to-fuel ratio. According to information received from Solar, SoloNOx can reduce NO_X exhaust concentrations to 15 ppmv on the Mars T-15000 units. This corresponds to a control efficiency of approximately 90%.

[6] Ibid.

Enterprise requested quotes for dry low NO_x burners for the GE Frame 5 Turbines from Baker Hughes. The vendor stated that no burners were currently commercially available. Therefore, this option is not considered technically feasible for the GE Frame 5 units.

2.1.2.3. Water/Steam Injection

Water or steam injection is a technology that has been demonstrated to effectively suppress NO_X emissions from gas turbines. The effect of water and steam injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.

Water or steam injection is capable of reducing NO_x formation in the GE Frame 5 turbines with a control efficiency of 15%.[7]

Enterprise received information from Solar stating that the Mars T-15000 units cannot support steam injection and that Solar does not offer water injection equipment. Solar also stated that, while a third-party vendor may be able to develop water injection controls for the Mars Turbines, such controls might create a risk of damaging this equipment and any damage caused by water injection would not be covered under the equipment's warranty. Based on the statements from Solar regarding the installation of water and steam injection equipment, Enterprise does not consider this control technically feasible at these units.

However, Enterprise engineers believe that water or steam injection is feasible for the GE Frame 5 Turbines.

2.1.2.4. Selective Catalytic Reduction Systems

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust stream at a point downstream of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[8] The chemical reactions for this process are shown in the equations below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O \quad \text{(Equation 1)}$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O \quad \text{(Equation 2)}$$

An SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and electronic control system. The electronic controls regulate the quantity of reagent injected as a function of turbine load, speed, and temperature, so NO_X emissions reductions can be achieved. The lifespan of the catalyst is primarily determined by poisoning of active sites by flue gas constituents; thermal sintering, or compacting, of active sites due to high temperatures in the reactor; fouling caused by ammonia-sulfur salts and particulate matter in the gas; and erosion due to high gas velocities.[9]

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as ammonia slip. Unreacted ammonia in the exhaust can form

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[7] Ibid.
[8] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
[9] Ibid.

ammonium sulfates, which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.[10]

In order for the SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 °F and 850 °F), dependent on the material of the catalyst. Exhaust gas temperatures greater than the upper limit will cause the NO_X and ammonia to pass through the catalyst unreacted.[11]

An onsite evaluation was conducted at the Chaco facility during which measurements were taken of any feasible locations for SCR equipment. These measurements took into consideration the amount of buffer space needed to maintain accessibility to equipment and to avoid compromising worker safety. Based on size estimates of SCR units provided by CECO-Peerless, Enterprise determined that it is not possible to install these units at the Chaco facility.

2.2. TWO-STROKE LEAN-BURN ENGINES

The Chaco Gas Plant has three natural gas-fired two-stroke lean-burn engines, Units 12 through 14, that are subject to this four-factor analysis. The only pollutant subject to evaluation for these units is NO_X. Please note that in regards to these vintage Clark TLA-10 engines, there is no OEM support for these units.

2.2.1. Two-Stroke Lean-Burn Engines Background

A reciprocating internal combustion engine (RICE) is a device that uses the combustion of fuel and air in an internal chamber to generate a reciprocating motion and convert heat energy into mechanical work. The units use a piston to draw air and fuel into the combustion chamber and compress them. The compressed air/fuel mixture is then ignited, generating combustion in the chamber. The energy of combustion pushes out the piston, turning a crankshaft and producing mechanical work. In the same cycle, the products of combustion remaining in the chamber are released and exhausted from the unit.

Natural gas-fired RICE are categorized according to multiple design classes, including two-stroke lean-burn (2SLB), four-stroke lean-burn (4SLB), and four-stroke rich-burn (4SRB). The four-stroke design uses four strokes of the piston, or two turns of the crankshaft, to complete the power cycle. The two-stroke design completes the power cycle in a single revolution of the crankshaft. Rich-burn engines are designed to operate close to the stoichiometric, or chemically balanced, air-to-fuel ratio (around 16:1), with exhaust oxygen levels less than 4%, while lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1), with exhaust oxygen levels of 12% or more. The units at the Chaco Gas Plant evaluated here are 2SLB engines.

NO_X is formed in reciprocating engines via three mechanisms:

(1) Thermal NO_X - the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion,
(2) Fuel NO_X - the evolution and reaction of fuel-bound nitrogen compounds with oxygen, and
(3) Prompt NO_X - the early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

These engines use natural gas fuel, which contains a negligible amount of nitrogen compounds. Therefore, the formation of fuel and prompt NO_X will be insignificant. This analysis thus focuses on thermal NO_X. The rate of NO_X formation through the thermal NO_X mechanism is highly dependent upon the air-to-fuel ratio, combustion

[10] Ibid.
[11] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines."

temperature, and residence time at the combustion temperature. Maximum thermal NO_X formation occurs near the stoichiometric air-to-fuel mixture ratio because combustion temperatures are greatest at this ratio.[12]

NO_X reduction in natural gas-fired RICE can be accomplished by three general methods, as follows:

(1) Parametric control methods, such as adjusting the timing or operating parameters.
(2) Combustion control techniques, for example, reducing the peak flame temperature or introducing inerts that limit initial NO_X formation.
(3) Post-combustion NO_X control technologies, which employ various strategies to chemically reduce NO_X to elemental nitrogen (N_2).

The potential to emit (PTE) from each engine is reported in the facility's NSR (1555-M7) and Title V (116-R2-M1) permits, as well as above in Table 1. NO_X emissions from the RICE are calculated using stack test data collected on 4/18/1995. The maximum emission rate was used to represent emissions with a 5% safety factor to account for any variability in engine emissions. The maximum hourly emission rate corresponds to a NO_X exhaust concentration of 1032 ppmv.

2.2.2. Potential NO_X Controls for 2SLB Engines

The categories of retrofit control equipment that were identified for 2SLB reciprocating engines during a comprehensive review of the RBLC and available technical literature are reported in Table 3. A detailed discussion, including a description, the technical feasibility, and the anticipated performance of each control, is provided below.

Table 3. Potential Control Options for 2SLB RICE

Control Equipment	Technically Feasible	NO_X Control Efficiency
Good Combustion Practices and Fuel Selection	**Base Case**	**N/A**
Selective Catalytic Reduction	**No**	**N/A**
Clean Burn Technology	**Base Case**	**N/A**

2.2.2.1. Good Combustion Practices and Fuel Selection

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. Applying concepts from engineering knowledge, experience, and the manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for the equipment involved, and using pipeline quality natural gas. If good combustion practices are maintained, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from combustion turbines; therefore, it has been determined that this method of NO_X control is

[12] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines."

feasible for the units at Chaco. However, these practices are currently in use at Chaco, as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices has been included in this report.

2.2.2.2. Selective Catalytic Reduction Systems

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust stream at a point downstream of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O). The chemical reactions for this process are shown in the equations below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O \quad \text{(Equation 1)}$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O \quad \text{(Equation 2)}$$

An SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and electronic controls to accurately meter the quantity of reagent injected as a function of engine load, speed, temperature, and NOx emissions reductions to be achieved. The lifespan of the catalyst is primarily determined by the erosion caused by the flue gas, deactivation caused by ammonium bisulfate (NH_4HSO_4) poisoning, and the build-up of and fouling by the catalyst.

For the SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 °F and 850 °F), dependent on the material of the catalyst. Exhaust gas temperatures greater than the upper limit will cause the NO_X and ammonia to pass through the catalyst unreacted.

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as ammonia slip. Unreacted reagent in the exhaust can form ammonium sulfates, which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.[13]

In engines that typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, either causing periods of ammonia slip or resulting in amounts of ammonia that are insufficient to obtain the emission reductions needed.[14]

An onsite evaluation was conducted at the Chaco facility during which measurements were taken of any feasible locations for SCR equipment. These measurements took into consideration the amount of buffer space needed to maintain accessibility to equipment and to avoid compromising worker safety. While installing an SCR on a two-stroke lean burn engine is not typical and may or may not be an effective means of NO_X reduction for such an engine, Enterprise determined that, based on the space limitations at Chaco, it would not be possible in any event to install SCR controls on the engines.

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[13] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

[14] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines."

2.2.2.3. Clean Burn Technology

Clean Burn Technology (CBT) is a term for utilizing combustion mixtures in engines with fuel-lean air-to-fuel ratios. This method of reducing NO_X emissions involves reconfiguring the engines by adding or enhancing an air-to-fuel-ratio controller, making the unit capable of operating at these more desirable ratios.

Rich-burn engines are normally designed to operate close to the stoichiometric, or chemically balanced, air-to-fuel ratio of 16:1, while lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1). A combustion mixture with a higher air-to-fuel ratio results in reduced NO_X emissions because using fuel-lean mixtures lowers the combustion temperature by diluting energy input. 2SLB engines are typically, by design, configured to operate at the high air-to-fuel ratios employed in CBT; however, further increasing the air-to-fuel ratio in lean-burn engines can decrease NO_X emissions.[15]

In order to avoid de-rating the engine, combustion air must be increased at constant fuel flow. To achieve this, the engine will need to be retrofitted with a turbocharger, which forces additional air into the combustion chamber, as well as an automatic air-to-fuel-ratio controller.

Many 2SLB engines, such as naturally aspirated engines, do not have identical air-to-fuel ratios in each cylinder, which can result in limited ability to vary the air-to-fuel ratio. To maintain acceptable engine performance at lean conditions, high energy ignition systems (HEIS) have been developed that promote flame stability at very lean conditions.

The Clark TLA-10 engines at Chaco are currently operating with CBT.

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[15] State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines, State of New Jersey Department of Environmental Protection, 2003.

Enterprise has evaluated the costs of implementing the technically feasible control technologies at Chaco as thoroughly as possible in the time provided to complete this assessment. The cost estimates presented below are calculated according to methods and recommendations described in the EPA Air Pollution Control Cost Manual.[16]

Emission inventory data and stack test data from 2016 were used to assess the baseline emissions for these units.

3.1. GE FRAME 5 TURBINE CONTROLS

Table 4. Cost Analysis Summary of Technically Feasible Controls for GE Frame 5 Turbines

Control Equipment	Unit No.	Cost Effectiveness	Cost Factors
Water Injection	17	$106,606 per ton	Equipment, engineering, and installation costs. Operating and incremental OEM inspection costs.
	18	$106,784 per ton	
Steam Injection	17	$148,512 per ton	Equipment, engineering, and installation costs. Operating and incremental OEM inspection costs.
	18	$148,760 per ton	

3.1.1. Water Injection

Enterprise received a cost estimate from Baker Hughes to implement water injection control on the GE Frame 5 turbines at the Chaco Gas Plant (Units 17 and 18). This cost estimate is $6.6 million per unit in equipment cost, plus an additional $1.2 million per unit associated with annual operating cost. The control efficiency for water injection is estimated to be 15%, resulting in an emission rate reduction of 19.02 tpy and 18.99 tpy for Units 17 and 18, respectively. The projected useful life of this control equipment is 15 years. This results in an estimated control cost effectiveness of $106,606 per ton and $106,784 per ton of reduced NO_X emissions for Units 17 and 18, respectively.

3.1.2. Steam Injection

Enterprise received a cost estimate from Baker Hughes to implement steam injection control on the GE Frame 5 turbines at the Chaco Gas Plant. This cost estimate is $8.7 million per unit in equipment cost, plus an additional $1.8 million per unit associated with annual operating cost. The control efficiency for steam injection is estimated to be 15%, resulting in an emission rate reduction of 19.02 tpy and 18.99 tpy for Units 17 and 18, respectively. The projected useful life of this control equipment is 15 years. This results in an estimated control cost effectiveness of $148,512 per ton and $148,760 per ton of reduced NO_X emissions for Units 17 and 18, respectively.

[16] U.S. EPA, "Air Pollution Control Cost Manual," available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

3.2. SOLAR MARS T-15000 TURBINE CONTROLS

Table 5. Cost Analysis Summary of Technically Feasible Controls for Mars T-15000 Turbines

Control Equipment	Unit No.	Cost Effectiveness	Cost Factors
SoloNOx	35	$6,800 per ton	Equipment costs, annual overhaul and labor costs
	36	$6,668 per ton	
	37	$9,435 per ton	

3.2.1. SoloNOx

For the Solar Mars T-15000 turbines (Units 35, 36, and 37), Enterprise received capital cost estimates from Solar for the SoloNOx control equipment of $5.6 million, $5.4 million, and $5.4 million for Units 35, 36, and 37, respectively. Based on equipment overhaul cost information provided by Solar, other associated annual costs are estimated to be $124,567 per unit. The expected useful life of this control equipment is 20 years. Based on the target NOx exhaust concentration of 15 ppmv provided by Solar, the expected control efficiencies associated with SoloNOx are 88%, 88%, and 85% for Units 35, 36, and 37, respectively. This results in an amortized cost effectiveness of $6,800, $6,668, and $9,435 per ton for Units 35, 36, and 37, respectively.

4. TIME NECESSARY FOR COMPLIANCE

The second factor in this analysis is the time necessary for compliance. Consideration of this factor involves estimating the time required for a source to implement a potential control measure. This information is provided here in order to advise the NMED of Enterprise's projection of a reasonable compliance timeline based on the equipment and site-specific considerations that could affect the time necessary to comply.

Enterprise estimates that approximately 3 to 4 years would be needed to budget for, design, procure, and construct those categories of control equipment discussed in this report that would be technically feasible to install on the respective units.

5. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS OF COMPLIANCE

This section addresses the potential energy and non-air quality environmental impacts that would result from installation of technically feasible control options at Chaco. Consideration of energy impacts involves assessing the impact of a control measure on the amount of energy that the source would have to consume. Non-air quality environmental impacts are assessed based on the effect of the control on non-air environmental media. Some examples of non-air quality environmental impacts include water resource depletion, solid waste generation, increased noise and odor pollution, and increased land usage.

5.1. GE FRAME 5 TURBINE AND SOLAR MARS T-15000 TURBINE CONTROLS

5.1.1. Water and Steam Injection

Water or steam injection is usually accompanied by an efficiency penalty (typically 2% to 3%) but an increase in power output (typically 5% to 6%).[17] The increase in power output results from the increased mass flow required to maintain the turbine inlet temperature at the manufacturer's specifications. Both CO and VOC emissions are significantly increased by water injection, with the level of CO and VOC emission increases dependent on the amount of water injection.[18] This increase in CO and VOC emissions could potentially warrant the installation of oxidation catalyst, resulting in significant additional costs to implement water injection.

5.1.2. SoloNO$_X$

There would be no anticipated unique or site-specific energy or non-air quality environmental impacts from installation and operation of SoloNO$_X$ on the Mars T-15000 turbines at Chaco.

[17] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines."

[18] Ibid.

The anticipated remaining useful life of each source is addressed here for the NMED's consideration. The assessment of this factor involves estimating how long the sources analyzed will remain in operation and the lifetime of potential control measures, accounting for equipment and site-specific limitations.

40 CFR Part 51, Appendix Y includes guidance on the characterization of this factor, stating that the remaining useful life of a source will typically be longer than the useful life of the emission control system.[19] Therefore, it is appropriate to annualize compliance costs based on the useful life of the control equipment, rather than the life of the source.

6.1. GE FRAME 5 TURBINE CONTROLS

6.1.1. Water and Steam Injection

The estimated useful life of a water or steam injection control system is 15 years. This estimate has been incorporated in the cost analysis section in calculating the total annualized cost of the control.

6.2. SOLAR MARS T-15000 TURBINE CONTROLS

6.2.1. SoloNO$_X$

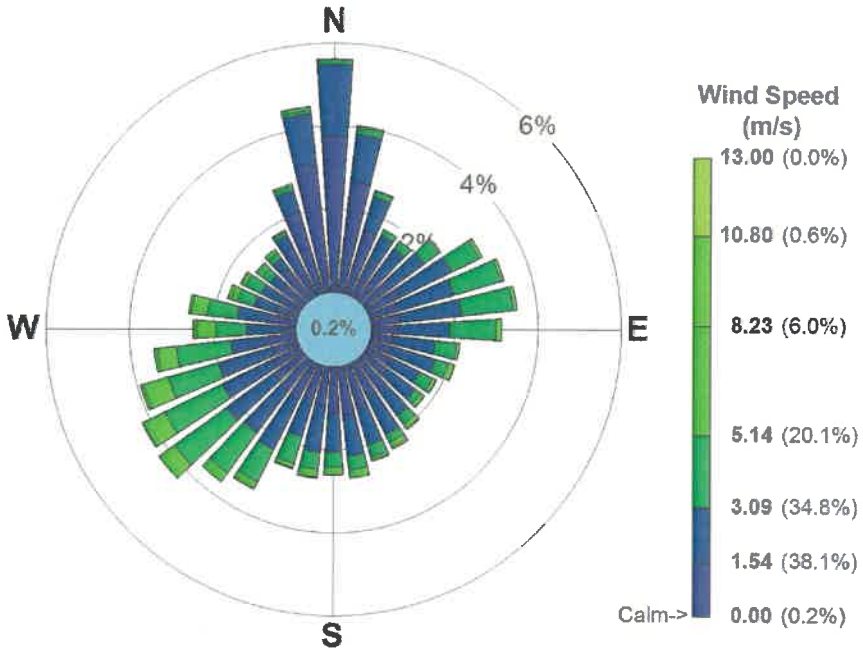
The estimated useful life of a SoloNO$_X$ control is 20 years. This estimate has been incorporated in the cost analysis section in calculating the total annualized cost of the control.

[19] 40 CFR 51, Appendix Y, Section IV.D.4.k.

Enterprise does not believe that implementing any of the evaluated controls would meaningfully improve visibility in nearby Class I areas based on climatological data and ambient pollutant data.

The Chaco Gas Plant is located approximately 50 miles from the Mesa Verde Class I area at a wind vector range of approximately 155 degrees to 165 degrees (SSE). According to 2015 meteorological data collected in Bloomfield, NM, which is presented in Figure 1 below, wind blows from this direction at a frequency of only 2.4%. Moreover, when the wind direction is within this range, the wind speed is typically relatively low; the frequency of wind speeds greater than 3.09 m/s (or ~7 mph) is only 0.3%, or about 25 hours per year. Higher wind speeds would be needed to effectively transport emissions from Chaco to the Mesa Verde Class I area. Moreover, over the 50 miles of transport, pollutants undergo significant dispersion. While full dispersion and photochemical modeling would be needed to more robustly evaluate Chaco's impact, based on this evidence, Chaco's impact on visibility is likely insignificant.

Figure 1. Windrose Reporting 2015 Wind Direction and Speed in Bloomfield, NM



Additionally, according to aerosol composition data reported during visibility-impaired periods at the nearby San Pedro Parks and Mesa Verde IMPROVE Monitors, the main contributing pollutant to anthropogenic regional haze is ammonium sulfate.[20] Therefore, installing NO_X controls on the units at Chaco would not significantly improve visibility.

[20] See, e.g., U.S. EPA, Technical Support Document for EPA's Updated 2028 Regional Haze Modeling (Sept. 2019), App. B at pp. B-55 (Fig. 52), B-79 (Fig. 76); 2007 to 2017 Regional Haze Trends (https://www.env.nm.gov/wp content/uploads/sites/2/2019/02/2000_2017_trends-in-NM.pdf).

8. SUPPORTING DOCUMENTATION

Enterprise Field Services, LLC
Chaco Gas Plant

GE Frame 5 Turbines	Interest Rate:	8.38%	
Unit 17			
	Water/Steam Injection Period:	15 years	

Base Emissions

NO_X ppm:		54.7 ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:		29.15 lb/hr	<-- From 2016 Stack Test Data
Hours of Operation:		8701.50 hours	<-- From 2016 Stack Test Data
NO_X tpy:		126.82 tpy	<-- Calculated

Water Injection

NO_X guarantee:		46 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:		24.78 lb/hr	
NO_X tpy:		107.80 tpy	
Total Cap Investment	$	6,606,100	<-- Equipment, Engineering and Installation
Annualized TCI:	$	789,716	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	1,238,327	<-- Inspection and operating costs
Total Annual Costs:	$	2,028,043	
Emissions Reduction:		19.02 tpy	
Cost Effectiveness:	**$**	**106,606.41**	**$/ton**

Steam Injection

NO_X guarantee:		46 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:		24.78 lb/hr	
NO_X tpy:		107.80 tpy	
Total Cap Investment	$	8,700,700	<-- Equipment, Engineering and Installation
Annualized TCI:	$	1,040,112	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	1,785,126	<-- Inspection and operating costs
Total Annual Costs:	$	2,825,238	
Emissions Reduction:		19.02 tpy	
Cost Effectiveness:	**$**	**148,511.84**	**$/ton**

Enterprise Field Services, LLC
Chaco Gas Plant

GE Frame 5 Turbines	Interest Rate:	8.38%	
Unit 18			
	Water/Steam Injection Period:	15 years	

Base Emissions

NO_X ppm:		48.7 ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:		29.15 lb/hr	<-- From 2016 Stack Test Data
Hours of Operation:		8687.00 hours	<-- From 2016 Stack Test Data
NO_X tpy:		126.61 tpy	<-- Calculated

Water Injection

NO_X guarantee:		41 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:		24.78 lb/hr	
NO_X tpy:		107.62 tpy	
Total Cap Investment	$	6,606,100	<-- Equipment, Engineering and Installation
Annualized TCI:	$	789,716	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	1,238,327	<-- Inspection and operating costs
Total Annual Costs:	$	2,028,043	
Emissions Reduction:		18.99 tpy	
Cost Effectiveness:	**$**	**106,784.35**	**$/ton**

Steam Injection

NO_X guarantee:		41 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:		24.78 lb/hr	
NO_X tpy:		107.62 tpy	
Total Cap Investment	$	8,700,700	<-- Equipment, Engineering and Installation
Annualized TCI:	$	1,040,112	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	1,785,126	<-- Inspection and operating costs
Total Annual Costs:	$	2,825,238	
Emissions Reduction:		18.99 tpy	
Cost Effectiveness:	**$**	**148,759.74**	**$/ton**

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbines	Interest Rate:	8.38%	
Unit 35			
	SoloNOx Period:	20 years	

Base Emissions			
NO_X ppm:	125	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:	27.72	lb/hr	<-- From 2016 Stack Test Data
Hours of Operation:	8623.50	hours	<-- From 2016 Stack Test Data
NO_X tpy:	119.52	tpy	<-- Calculated

SoLoNO$_X$			
NO_X guarantee:	15	ppm	<-- From Solar
NO_X lb/hr:	3.33	lb/hr	
NO_X tpy:	14.34	tpy	
Total Cap Investment	$ 5,639,300		<-- Equipment, Engineering and Installation
Annualized TCI:	$ 590,647		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 124,567		<-- Incremental overhaul costs
Total Annual Costs:	$ 715,215		
Emissions Reduction:	105.18	tpy	
Cost Effectiveness:	**$ 6,800.13**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbines	Interest Rate:	8.38%	
Unit 36			
	SoloNOx Period:	20 years	

Base Emissions			
NO_X ppm:	122	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:	28.00	lb/hr	<-- Calculated based on NOx concentration
Hours of Operation:	8418.50	hours	<-- From 2016 Stack Test Data
NO_X tpy:	117.84	tpy	<-- Calculated

SoLoNO$_X$				
NO_X guarantee:		15	ppm	<-- from Solar
NO_X lb/hr:		3.45	lb/hr	
NO_X tpy:		14.52	tpy	
Total Cap Investment	$	5,388,700		<-- Equipment, Engineering and Installation
Annualized TCI:	$	564,400		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	124,567		<-- Incremental overhaul costs
Total Annual Costs:	$	688,967		
Emissions Reduction:		103.32	tpy	
Cost Effectiveness:	**$**	**6,668.02**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbines	Interest Rate:	8.38%	
Unit 37			
	SoloNOx Period:	20 years	

Base Emissions

NO_X ppm:	103	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:	22.93	lb/hr	<-- Calculated based on NOx concentration
Hours of Operation:	7497.00	hours	<-- From 2016 Stack Test Data
NO_X tpy:	85.97	tpy	<-- Calculated

SoLoNO$_X$

NO_X guarantee:	15	ppm	<-- from Solar
NO_X lb/hr:	3.33	lb/hr	
NO_X tpy:	12.48	tpy	
Total Cap Investment	$ 5,430,500		<-- Equipment, Engineering and Installation
Annualized TCI:	$ 568,778		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 124,567		<-- Incremental overhaul costs
Total Annual Costs:	$ 693,345		
Emissions Reduction:	73.49	tpy	
Cost Effectiveness:	**$ 9,434.46**	**$/ton**	

Enterprise Products

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS HOLDINGS LLC
(General Partner)

ENTERPRISE PRODUCTS OPERATING LLC

February 24, 2020

7019 0140 0000 4305 2046
Return Receipt Requested

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505

Re: NMED Follow-Up Letter Response
Regional Haze Four-Factor Analysis
Enterprise Field Services, LLC
Chaco Gas Plant

Mr. Singleton:

Enterprise Field Services, LLC (Enterprise) submits herein to the New Mexico Environment Department (NMED) the enclosed responses to the follow-up questions contained in NMED correspondence dated December 23, 2019 for the Regional Haze Four-Factor Analysis submitted for the Enterprise Chaco Gas Plant located in San Juan County, New Mexico.

Enterprise considers the information included in Appendix B of the enclosed response to be confidential business information (CBI) and requests that it be treated as such to the full extent applicable.

Should you have questions or require further information regarding this submittal, please contact Tucker Jacobson at 713-381-4313 (wtjacobson@eprod.com) or Bradley Cooley at 713-381-5828.

Thank you,
Enterprise Field Services, LLC

W. Tucker Jacobson
Scientist, Senior Environmental

Bradley J. Cooley, P.E.
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/bjm
Enclosure

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REGIONAL HAZE FOUR-FACTOR ANALYSIS
NMED FOLLOW-UP LETTER RESPONSE
Enterprise Field Services, LLC, Chaco Gas Plant

Prepared By:

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Jake Zenker - Consultant

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February 2020

Project 203201.0011

Trinity Consultants

Environmental solutions delivered uncommonly well

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1. ENGINES

The NMED requested the following information regarding the three Clark 2SLB engines (Units 12, 13, and 14) installed at the Chaco Gas Plant.

a. *Please provide a more thorough Selective Catalytic Control (SCR) evaluation. Include documentation of the spacing evaluation on SCR equipment and verify how that makes it impossible to install at the site. Are there other possible installation designs and what would the potential emissions reductions be? If there are other restrictions or problems with potential SCR installation, please provide documentation.*

Response: Enterprise received information from CECO-Peerless (Natalie Boone) on October 17, 2019, which stated that an area of approximately 40' by 20' is required for an SCR unit. This correspondence is included in Appendix B. The size estimate was not specific to a specific configuration of an SCR, but rather was a generic conservative estimate for any SCR unit. As mentioned in our original report, space at the Chaco Gas Plant is restricted. We have included an aerial image of the facility in Appendix A with measurement overlays to demonstrate that the limited space precludes the option of installing SCR.

b. *Please verify and provide documentation that control systems have not yet been developed for SCR controls that can handle variable load engines. This appears to be one main reason that SCR has not been implemented on 2SLB internal combustion engines in oil and gas midstream operations.*

Response: Per our initial submission, AP-42 Section 3.2 is referenced to support this claim. Section 3.2.4.2 states the following: "SCR is most suitable for lean-burn engines operated at constant loads, and can achieve efficiencies as high as 90 percent. For engines which typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia to gain the reductions needed."[1]

c. *Consider Good Combustion Practices (GCP) and the routine maintenance as controls and provide the details how both would be achieved including a maintenance schedule and procedures.*

Response: As stated in our original submittal, Good Combustion Practices (GCP) are currently implemented at the Chaco Gas Plant. The following routine maintenance and monitoring are conducted on the Clark engines: Engine oil is sampled monthly, internal inspections are conducted annually, emissions testing is conducted annually, and the engines' turbochargers are replaced every 5 years. The following maintenance kits are replaced in a cycle; one kit is replaced every 2,000 hours of operation:

Kit A – The following parts are replaced: Ignition wiring, spark plugs and wires, primary and secondary coils, and inlet filters.

[1] AP-42 Section 3.2.4.2 Natural Gas-fired Reciprocating Engines, Control Technologies, Control Techniques for Lean-burn Reciprocating Engines, Selective Catalytic Reduction.

Kit B – Air filters are replaced.

Kit C – Engine speed sensors, wiring, and cables are replaced. Yard valve, waste gate, and jacket water valve positionings are checked and corrected.

Kit D – Air filters, thermocouples, and thermocouple wiring are replaced.

For each of the kits, the transmitter calibration is checked; Thermocouple, pressure level. and vibration function are tested; yard valve positioning, waste gate positioning, and jacket water valve positioning are checked.

d. *Consider and include a discussion on the feasibility and cost of technology that limits engine capacity to reduce NO_X emissions. Also evaluate limitations on engine operating hours or shutting down engines that are no longer needed to reduce emissions.*

Response: Enterprise cannot commit to decreasing engine capacity as the facility must meet contractual demands. Additionally, it is important to retain the flexibility to operate at maximum capacity to facilitate the transfer of gas from upstream facilities and to maintain a stable infrastructure to handle that demand..

e. *Please consider and include a discussion on the feasibility of replacing natural gas-fueled engines/turbines with commercial electric powered compressors.*

Response: 40 CFR 51 Appendix Y, states the following: "We do not consider BART as a requirement to redesign the source when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, we do not require the BART analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting on a per unit basis."[2] Replacing the existing combustion engines with electric powered engines may be feasible; however, numerous engineering evaluations would be required, and it is anticipated that there would be substantial obstacles in converting these units to electric.

f. *Provide information on the Clean Burn Technology (CBT) used in the base case. Consider and include a discussion of variations of CBT used to reduce NO_X emissions that may be more effective than the existing package if available. Please include cost and efficiencies in analysis.*

Response: Altronic Ignition Control Systems and engine balancing are currently being implemented on these units. At this time, Enterprise has not identified any other variations of CBT for the Clark TLA-10 model; if any other variations are identified to be available and feasible they will be considered.

g. *Provide vendor specifications that include the cost information, recommendations, and equipment specifications for the engine cost control estimates.*

Response: As stated above, the engines utilize Altronic Ignition Control Systems and engine balancing to control NO_X emissions. At this time, Enterprise has not identified any other

[2] 40 CFR 51 Appendix Y: Guidelines for BART Determinations Under the Regional Haze Rule, Section IV.D.1.5.

variations of CBT for the Clark TLA-10 model; if any other variations are identified to be available and feasible they will be considered.

h. *Provide any electronic spreadsheets used for control technology calculations.*

Response: At this time, Enterprise has not identified any other variations of CBT for the Clark TLA-10 model; if any other variations are identified to be available and feasible they will be considered.

2. FLARING

The NMED requested the following information regarding the flares installed at the Chaco Gas Plant.

a. *Provide a description of each flare, the design and type, and its purpose.*

Response: Units 42 and 43 are a staged flare system. Unit 42 is a Zeeco UFA-6-24 candlestick flare and Unit 43 is a Zeeco four-staged ground level flare. Although they are identified separately, the units consist of one ground flare. The flare functions as a process flare and an emergency/upset flare. Under normal operation, the flare has a continuous methane pilot and purge gas estimated at 200 scf/hr. The flare controls emissions from compressor station vents, drain valves, and relief valves from the inlet of the plant. In addition, NGL and methanol bullet tanks, storage tank relief valves, pressure regulator valves, drain valves, and vents associated with the inlet compression are tied to the flare for safety.

Unit 44 is a flare used as a process flare, a startup, shutdown, and maintenance (SSM) flare, and an emergency/upset control device for the cryogenic liquids plant. Under normal conditions, the flare operates on pilot and purge gas with a flow of approximately 200 scf/hr (per manufacturer's data), and condenser off-gas from the glycol dehydration unit with a flow of approximately 300 scf/hr is routed to the flare for destruction. This flare will also serve to control emissions from the methyldiethanolamine (MDEA) sweetening unit when the thermal oxidizer is down.

b. *Complete a review and include an analysis about how the entire facility and/or source specific operations can be improved to reduce the frequency of Startup, Shutdown and Maintenance (SSM) flaring events. If it is not possible to make any improvements to the facility or its processes to reduce SSM flaring events, then please explain why.*

Response: Enterprise does not believe that any control practices or techniques could be implemented to reduce flaring emissions at this facility. The units have hourly emission rates of less than 10 pounds per hour and/or 5 tons per year for SO_2. As a result, none of these flares are required to undergo a Four-Factor Analysis for SO_2. In regard to NO_X, only Flare 44 is over the 10 lb/hr and 5 tons per year threshold; however, its emissions are quite small in regard to impacting the regional haze at Mesa Verde.

3. TURBINES

The NMED requested the following information for NO_X from Turbine Unit Numbers 35, 36, 37, 17, and 18.

a. *Please provide a more thorough SCR evaluation. Include documentation of the spacing evaluation on SCR equipment and verify how that makes it impossible to install at the site. Are there other possibilities of installation designs and what would the potential emissions reductions be? If there are other restrictions or problems with potential SCR installation, please provide documentation.*

Response: Enterprise received information from CECO-Peerless (Natalie Boone) on October 17, 2019, which stated that an area of approximately 40' by 20' is required for an SCR unit. This correspondence is included in Appendix B. The size estimate was not specific to a specific configuration of an SCR, but rather was a generic conservative estimate for any SCR unit. As mentioned in our original report, space at the Chaco Gas Plant is restricted. We have included an aerial image of the facility in Appendix A with measurement overlays to demonstrate that the limited space precludes the option of installing SCR.

At this time, Enterprise has not fully evaluated engineering concerns associated with the installation of SCR controls as SCR was determined to be technically infeasible during the preparation of the initial four-factor report. Since a full engineering study was not conducted to determine specific design and operating parameters, Enterprise projects that a minimum NO_X control efficiency of 65% could be achieved with the SCR, according to AP-42. [3]

b. *Provide vendor specifications for the SoLoNO$_X$ Dry Low NO$_X$ (DLN) combustion technology to include the guaranteed NO$_X$ emission rates used in cost analysis, the cost information, recommendations, and equipment specifications for the turbine control estimates.*

Response: A vendor quote from Solar for the SoLoNO$_X$ conversion is attached (sent September 19, 2019). There are two components to the total cost considered: (1) the capital cost of the SoLoNO$_X$ unit (which includes equipment cost from Solar, installation, engineering, and inspection) and (2) the incremental annual overhaul costs. The incremental annual overhaul costs are based on hourly overhaul rates for the gas producer and power turbine, which differ for units that are operating with or without SoLoNO$_X$. This information was provided by Solar on October 22, 2019. The capital and overhaul costs are amortized with the specified interest rate to calculate an annualized total capital investment. This information is submitted with this response in Appendix B.

c. *How will upgrading the turbine combustors with SoLoNO$_X$ affect the turbine capacities and the emission rates of NO$_X$ and CO?*

Response: According to documentation received from Solar on September 19, 2019, the SoLoNO$_X$ unit would reduce the NO_X exhaust concentration from 125 ppm to 15 ppm. According, to AP-42, CO emissions would be increased from the implementation of this control,[4] but Solar has not provided any guidance on the magnitude of the emission increase.

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[3] AP-42 Section 3.1.4.3 Stationary Gas Turbines, Control Technologies, Catalytic Reduction System.

[4] AP-42 Section 3.1.4.2 Stationary Gas Turbines, Control Technologies, Dry Controls.

d. *Provide the statement by the turbine vendor stating why water injection is not technically feasible for Solar Turbines.*

Response: As discussed in Enterprise's original submission in November 2019, Solar stated on October 21, 2019 (*see* Appendix B to this report) that they do not offer water injection on the Mars 15000 turbine. As mentioned in Enterprise's November 2019 submission, it may be possible to install a third-party water-steam injection system on Solar turbines, but such a modification could void the turbines' warranty should damage to the unit be caused by the third-party equipment.

e. *Provide more detail of the GCP that have been implemented on the turbines, including routine inspections, maintenance and training schedules. It is unclear if these practices are fully optimized or conform to permit conditions alone.*

Response: As stated in Enterprise's original submission, Good Combustion Practices (GCP) are currently implemented at the Chaco Gas Plant. Regular maintenance activities for the Solar Mars 15000 turbines (Units 35, 36, and 37) include the following: Oil is sampled monthly and emission testing occurs annually. The following maintenance activities also occur annually: Air filters and oil filters are replaced, boroscope inspections and a water wash occur, and Solar representatives perform original equipment manufacturer (OEM) checks and emission testing. Additionally, all transmitters, levels, pressures, and vibration sensors are tested, and DC rundown tests occur.

f. *Please consider and include a discussion on the feasibility of replacing the natural gas-fueled turbines with commercial electric powered turbines.*

Response: 40 CFR 51 Appendix Y, states the following: "We do not consider BART as a requirement to redesign the source when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, we do not require the BART analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting on a per unit basis."[5] Replacing the existing turbines with electric powered motors may be feasible; however, numerous engineering evaluations would be required, and it is anticipated that there would be substantial obstacles in converting these units to electric.

g. *Provide the electronic spreadsheets used for control technology calculations.*

Response: The electronic spreadsheet used to quantify cost effectiveness has been submitted via email to NMED.

h. *Please include a discussion of the following control options to reduce NO_X emissions: catalytic combustion such as a XONON™ developed by Catalytic Combustion Systems, Incorporated (CESI), lean and staged combustion technology from turbine manufacturers other than Solar, and complete a four-factor analysis on technically feasible options. That Solar does not manufacturer a particular control method or turbine combustor is not grounds for eliminating an option for technical reasons.*

[5] 40 CFR 51 Appendix Y: Guidelines for BART Determinations Under the Regional Haze Rule, Section IV.D.1.5.

i. XONON™

Response: XONON is not a post combustion technology. The XONON combustor is completely contained within the combustion chamber of the turbine. As stated in the US EPA Environmental Technology Verification report, "The design of each Xonon™ combustor is customized to the particular turbine model and operating conditions of the application and would typically be defined through a collaborative effort with the manufacturer of the turbine to integrate the hardware into the design."[6] Moreover, the Air Pollution Training Institute Manual for Controlling NO_X Formation in Gas Turbines states that, "Both GE and Solar Turbines have successfully operated on a 7.5 MW and a 10 MW engine using the XONON combustion system. Both engines demonstrated performance at less-than 2.5 ppmvd at 15% O_2, but neither has yet made them commercially available, and it is not likely that they will."[7]

ii. Staged and Lean Combustion

Response: AP-42 Section 3.1.2 provides a technical background on turbine combustion. The second paragraph of that section describes lean-premixed staged combustion.[8] That paragraph defines lean-premixed staged combustion as a synonym for dry low NO_X. SoLoNO$_X$ is Solar's proprietary dry low NO_X combustor, which would be synonymous with this option. If such a technology were to be implemented, it would not be appropriate to use a third-party vendor for Solar turbines. The SoLoNO$_X$ burners are specifically designed to work effectively with Solar turbines and have been widely implemented on Solar's units. While it may be possible to install a third-party burner on Solar turbines, the performance cannot be guaranteed and, as stated by Solar in correspondence dated October 21, 2019 (Attachment B), such a modification could void the turbines' warranty should damage be caused to the unit by third-party equipment.

[6] Environmental Technology Verification Report – NO_X Control Technologies: Catalytica Combustion Systems, Inc. Xonon™ Flameless Combustion System, at 2 (December 2000). https://archive.epa.gov/nrmrl/archive-etv/web/pdf/05_vr_xonon.pdf.

[7] Air Pollution Training Manual Chapter 7 – Controlling NO_X Formation in Gas Turbines. (September 2009). https://www.apti-learn.net/lms/register/display_document.aspx?dID=39.

[8] AP-42 Section 3.1.2 Stationary Gas Turbines, Process Description.

APPENDIX A: AERIAL MAP WITH SCR DIMENSIONS



REFER TO CONFIDENTIAL BUSINESS INFORMATION (CBI) ATTACHMENT

Enterprise Products

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS HOLDINGS LLC
(General Partner)

ENTERPRISE PRODUCTS OPERATING LLC

October 1, 2020

7019 1640 0001 3129 8754
Return Receipt Requested

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505

Re: NMED Follow-Up Discussion Response
Regional Haze Four-Factor Analysis
Enterprise Field Services, LLC
Chaco Gas Plant

Mr. Singleton:

Enterprise Field Services, LLC ("Enterprise") submits herein to the New Mexico Environment Department (NMED) its responses to the follow-up requests from a virtual meeting held on August 28, 2020 for the Regional Haze Four-Factor Analysis submitted for the Enterprise Chaco Gas Plant located in San Juan County, New Mexico. The NMED requested information regarding six additional items identified as (a) through (f) in email correspondence dated September 2, 2020. Enterprise responded to each of the six items and committed to further developing and providing additional information for requests (b) and (c). The NMED follow-up requests and Enterprise responses for requests (b) and (c) are provided below.

Enterprise considers the information included in Attachment A of the enclosed response to be confidential business information (CBI) and requests that it be treated as such to the full extent of applicable law.

NMED Request (b): *We discussed an adjustment to the interest rate Enterprise originally used in its amortization of capital costs. You made an argument to use an interest rate higher than the adjusted rate of 3.25% NMED presented. Please provide in writing the reasoning for your higher interest rate (on top of the explanation provided in an email communication provided to NMED earlier this year), more precisely, the interest rate that would be specific to Enterprise for air pollution control projects. Note that no other New Mexico 4-factor submittal used an interest rate as high as the 8.38% you suggested would be appropriate to Enterprise. Providing official information from a potential lender would support your case when EPA and other entities review NMED's Regional Haze recommendations.*

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Enterprise Response: In our original Four-Factor Analysis, Enterprise used an annual interest rate of 8.38% based on its application of a 2018 FERC rulemaking that reflected an average capital structure for Enterprise's industry of 57% equity (with an average 10.55% annual return) and 43% debt (to which Enterprise applied the then-applicable prime rate of 5.5%). This approach tracked the basic manner in which Enterprise's industry raises funds, i.e. through a combination of investment equity and taking on debt. The NMED's response stated that Enterprise's proposed rate "is appropriate for pipeline operation and construction, not for air pollution control technologies. The prime rate [3.25%] or a rate specific to Enterprise should be used, and a rate representative of 2020 conditions."

Enterprise respectfully disagrees with the NMED's statement that the FERC methodology is only appropriate for pipeline construction and operation. As noted during our August 28, 2020 virtual meeting, Enterprise's cost of capital is based on the company's overall health and financial condition and generally is not sensitive to the specific purpose for which capital is raised. Put another way, Enterprise would not expect to obtain a lower interest rate on expenses for air pollution control equipment than for other types of expenses such as pipeline construction and operation. Accordingly, we continue to believe that the 8.38% rate derived from the FERC methodology would have been suitable for the Four-Factor Analysis. We also do not believe that the NMED's proposed prime rate of 3.25%, which reflects highly unusual but ultimately temporary conditions in the economy as the result of the COVID-19 pandemic, is a suitable basis for calculating the cost of control measures that would be implemented years in the future when interest rates are likely to return to higher levels more commensurate with their historical patterns.

Nonetheless, at the NMED's request, Enterprise has calculated a company-specific interest rate of 9.62% as of June 30, 2020 and requests that the NMED rely on this interest rate to calculate the cost-effectiveness of potential control measures on our facilities. This interest rate was calculated by Enterprise's Finance department using the Capital Asset Pricing Model. We emphasize that this interest rate reflects our company's overall cost of capital and is applicable to capital raised for a range of purposes, including air pollution control costs, construction of new facilities, or otherwise. The specific calculations behind this interest rate are described in the confidential white paper included as Attachment A. Enterprise consents to disclosure of the 9.62% rate and this explanation in the NMED's public record. However, we request that the NMED treat the white paper itself (i.e. Attachment A) as our confidential business information.

Enterprise has revised the cost-effectiveness calculations for potential retrofit control technologies for the combustion units subject to the Four-Factor Analysis at the Chaco Gas Plant using the calculated company-specific interest rate of 9.62%. The revised cost-effectiveness calculations are enclosed as Attachment B.

NMED Request (c): *Replacing turbines with electric compressors has not been excluded from consideration; therefore, a technical feasibility analysis and cost analysis is required. Given the deadline of September 10 for NMED to submit information to WRAP for the 2nd round PAC photochemical grid modeling, a qualitative ballpark estimate will suffice if you cannot put together*

a comprehensive analysis within the next week. However, a more complete analysis would be appreciated by the end of the month.

Enterprise Response: To assess the potential conversion of combustion driven compressors to electric driven compressors, numerous significant considerations require evaluation. For the purposes of this discussion, Enterprise has evaluated existing electrical capacity to determine the additional electrical capacity that likely would be required to provide equivalent station horsepower for the units that are subject to the Four-Factor Analysis. The total added electric load that would be required if the three Clark TLA-10 engines (Units 12, 13, and 14), two GE Frame 5 turbines (Units 17 and 18), and three Solar Mars T-15000 turbines (Units 35, 36, and 37) were converted to electric driven units is approximately 93,000 kilowatts (KW) or 93 megawatts (MW). The electric provider, Farmington Electric Utility System (FEUS), is at peak capacity and therefore would need to invest in a new electricity generating station to provide the additional 93 MW needed. The cost of a new generating station is not included in the analysis but is estimated to cost approximately $2,500/KW, or $232,500,000 for 93 MW. Additionally, the increased electricity demand would require upgrades to the utility transmission infrastructure from the generating station to the Chaco Gas Plant; these costs would be directly borne by Enterprise. The existing 46.7–mile, 69 kilovolt (kV) distribution system, including three substations, would need to be upgraded to 115 kV to provide the additional required load. In addition to replacing the eight combustion driven compressor packages with electric compressor packages, Enterprise would need to construct additional utility infrastructure within the Chaco Gas Plant to distribute the energy needed to drive the electric compressors. Cost-effectiveness figures for electrification of each unit (excluding third-party costs to install additional electricity generating capacity), including the cost estimation methodology used to estimate the total capital investment, is included in Attachment C. Please note that the electrification costs are based on best professional judgement and not reflective of an actual quoted facility-specific price. The timeline to implement electrification of the eight units at the Chaco Gas Plant would likely be between five and eight years, depending on the new third-party generating station source siting requirements, environmental permitting, and right of way negotiations. No consideration has been given to potential nitrogen oxide (NO_X) emissions as a result of generating the additional electrical capacity that would be necessary for electrification of the combustion units at the Chaco Gas Plant.

Enterprise does not believe that any further evaluation of electrification of the eight units at the Chaco Gas Plant is warranted. Electrification is not technically feasible because of the necessary additional power generation and utility infrastructure upgrades needed by the local utility over which Enterprise has no control. Additionally, redefining a source is not a retrofit control technology and is beyond the authority of the Regional Haze Rule.

Should you have any questions regarding this submittal, please contact Tucker Jacobson at (713) 381-4313 (wtjacobson@eprod.com) or Bradley Cooley at (713) 381-5828.

Sincerely,

Enterprise Field Services, LLC

W. Tucker Jacobson
Scientist, Senior Environmental

Bradley J. Cooley, P.E.
Director, Environmental

/bmh
Enclosure

Attachment A (Confidential Business Information)

Company-Specific Interest Rate Calculation

The Confidential information in this Attachment meets the conditions of NMAC § 20.2.1.115.B(3), as follows. Enterprise considers the information to be confidential, and requests that it be treated as such to the full extent of applicable law. We have taken reasonable measures to protect the confidentiality by keeping the information in secure data systems that are only available to authorized users, who are subject to confidentiality obligations per company policy, and by making this confidentiality claim. Further, neither NMED nor a third party could obtain the information without our consent, as this is information developed by Enterprise.

Attachment B

Revised Cost-Effectiveness Calculations with Company-Specific Interest Rate

Enterprise Field Services, LLC

Chaco Gas Plant

GE Frame 5 Turbine Unit 17	Interest Rate:	9.62%	<-- Company-specific interest rate as of 6/30/20
	Water/Steam Injection Period:	15 years	

Base Emissions

NO_X ppm:	54.7	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:	29.15	lb/hr	<-- From 2016 Stack Test Data
NO_X tpy:	126.82	tpy	<-- Calculated

Water Injection

NO_X guarantee:	46	ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:	24.78	lb/hr	
NO_X tpy:	107.80	tpy	
Total Cap Investment	$ 10,643,600		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,369,138		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,965,077		<-- Inspection and operating costs
Total Annual Costs:	$ 3,334,215		
Emissions Reduction:	19.02	tpy	
Cost Effectiveness:	**$ 175,266.80**	**$/ton**	

Steam Injection

NO_X guarantee:	46	ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:	24.78	lb/hr	
NO_X tpy:	107.80	tpy	
Total Cap Investment	$ 14,018,400		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,803,254		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 2,848,666		<-- Inspection and operating costs
Total Annual Costs:	$ 4,651,921		
Emissions Reduction:	19.02	tpy	
Cost Effectiveness:	**$ 244,533.50**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

GE Frame 5 Turbine Unit 18	Interest Rate:	9.62%	<-- Company-specific interest rate as of 6/30/20
	Water/Steam Injection Period:	15 years	

Base Emissions

NO_X ppm:	48.7	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:	29.15	lb/hr	<-- From 2016 Stack Test Data
NO_X tpy:	126.61	tpy	<-- Calculated

Water Injection

NO_X guarantee:	41	ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:	24.78	lb/hr	
NO_X tpy:	107.62	tpy	
Total Cap Investment	$ 10,643,600		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,369,138		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,965,077		<-- Inspection and operating costs
Total Annual Costs:	$ 3,334,215		
Emissions Reduction:	18.99	tpy	
Cost Effectiveness:	**$ 175,559.35**	**$/ton**	

Steam Injection

NO_X guarantee:	41	ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:	24.78	lb/hr	
NO_X tpy:	107.62	tpy	
Total Cap Investment	$ 14,018,400		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,803,254		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 2,848,666		<-- Inspection and operating costs
Total Annual Costs:	$ 4,651,921		
Emissions Reduction:	18.99	tpy	
Cost Effectiveness:	**$ 244,941.66**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbine Unit 35	Interest Rate:	9.62%	<-- Company-specific interest rate as of 6/30/20
	$SoloNO_X$ Period:	20	years

Base Emissions

NO_X ppm:	125	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:	27.72	lb/hr	<-- From 2016 Stack Test Data
NO_X tpy:	119.52	tpy	<-- Calculated

$SoLoNO_X$

NO_X guarantee:	15	ppm	<-- From Solar
NO_X lb/hr:	3.33	lb/hr	
NO_X tpy:	14.34	tpy	
Total Cap Investment	$ 9,086,000		<-- Control System Cost from Solar and estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,039,692		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 124,567		<-- Incremental annual inspection and overhaul costs for unit equipped with $SoloNO_X$
Total Annual Costs:	$ 1,164,259		
Emissions Reduction:	105.18	tpy	
Cost Effectiveness:	**$ 11,069.56**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbine Unit 36	Interest Rate:	9.62%	<-- Company-specific interest rate as of 6/30/20
	$SoloNO_X$ Period:	20 years	

Base Emissions

NO_X ppm:	122	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:	28.00	lb/hr	<-- Calculated based on NOx concentration
NO_X tpy:	117.84	tpy	<-- Calculated

$SoLoNO_X$

NO_X guarantee:	15	ppm	<-- from Solar
NO_X lb/hr:	3.45	lb/hr	
NO_X tpy:	14.52	tpy	
Total Cap Investment	$ 9,086,000		<-- Control System Cost from Solar and estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,039,692		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 124,567		<-- Incremental annual inspection and overhaul costs for unit equipped with $SoloNO_X$
Total Annual Costs:	$ 1,164,259		
Emissions Reduction:	103.32	tpy	
Cost Effectiveness:	**$ 11,268.03**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbine Unit 37	Interest Rate:	9.62%	<-- Company-specific interest rate as of 6/30/20
	$SoloNO_X$ Period:	20	years

Base Emissions

NO_X ppm:	103	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:	22.93	lb/hr	<-- Calculated based on NOx concentration
NO_X tpy:	85.97	tpy	<-- Calculated

$SoLoNO_X$

NO_X guarantee:	15	ppm	<-- from Solar
NO_X lb/hr:	3.33	lb/hr	
NO_X tpy:	12.48	tpy	
Total Cap Investment	$ 9,086,000		<-- Control System Cost from Solar and estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,039,692		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 124,567		<-- Incremental annual inspection and overhaul costs for unit equipped with $SoloNO_X$
Total Annual Costs:	$ 1,164,259		
Emissions Reduction:	73.49	tpy	
Cost Effectiveness:	**$ 15,842.26**	**$/ton**	

TOTAL CAPITAL INVESTEMENT COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
CHACO GAS PLANT

Chaco Gas Plant							
Cost Estimation Methodology Used:	**EPA Air Pollution Control Cost Manual Section 5.2, Chapter 1, Table 1.3[1]**						
Unit:	**17**		**18**		**35**	**36**	**37**
Control Technology:	**Water Injection**	**Steam Injection**	**Water Injection**	**Steam Injection**	**SoloNO$_X$**	**SoloNO$_X$**	**SoloNO$_X$**
Control System Cost (Estimate):	$ 4,100,000	$ 5,400,000	$ 4,100,000	$ 5,400,000	$ 3,500,000	$ 3,500,000	$ 3,500,000
PEC (Control System Cost*1.18):	$ 4,838,000	$ 6,372,000	$ 4,838,000	$ 6,372,000	$ 4,130,000	$ 4,130,000	$ 4,130,000
DIC (PEC*0.85)	$ 4,112,300	$ 5,416,200	$ 4,112,300	$ 5,416,200	$ 3,510,500	$ 3,510,500	$ 3,510,500
DC (PEC + DIC):	$ 8,950,300	$ 11,788,200	$ 8,950,300	$ 11,788,200	$ 7,640,500	$ 7,640,500	$ 7,640,500
IC (PEC*0.35) :	$ 1,693,300	$ 2,230,200	$ 1,693,300	$ 2,230,200	$ 1,445,500	$ 1,445,500	$ 1,445,500
Total Capital Investment (DC+IC):	**$ 10,643,600**	**$ 14,018,400**	**$ 10,643,600**	**$ 14,018,400**	**$ 9,086,000**	**$ 9,086,000**	**$ 9,086,000**

[1] https://www.epa.gov/sites/production/files/2020-07/documents/cs5-2ch1.pdf

PEC - Purchased Equipment Cost	Control equipment
DIC - Direct Installation Cost	Foundation/supports, handling/erection, electrical, piping, installation of ductwork, painting
DC - Direct Cost	PEC and DIC
IC - Indirect Cost	Engineering, Construction and field expenses, contractor fees, start-up, performance test, contingencies

Attachment C

Cost-Effectiveness Calculations for Electrification of Combustion Units

Enterprise Field Services, LLC

Chaco Gas Plant

Clark TLA-10 RICE Unit 12	Interest Rate:		9.62%	<-- Company-specific interest rate as of 6/30/20
	Period:		20	years
Base Emissions				
NO_X lb/hr:		27.75	lb/hr	<-- Calculated 2016-2018 average from EIQ
NO_X tpy:		105.87	tpy	<-- Calculated 2016-2018 average from EIQ
Electric Conversion				
NO_X guarantee:		0	ppm	
NO_X lb/hr:		0.00	lb/hr	
NO_X tpy:		0.00	tpy	
Total Cap Investment	$	27,138,590		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	3,105,411		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	-		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$	3,105,411		
Emissions Reduction:		105.87	tpy	
Cost Effectiveness:	**$**	**29,333.23**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Clark TLA-10 RICE Unit 13	Interest Rate:	9.62%	<-- Company-specific interest rate as of 6/30/20
	Period:	20	years

Base Emissions

NO_X lb/hr:	49.70	lb/hr	<-- Calculated 2016-2018 average from EIQ
NO_X tpy:	174.53	tpy	<-- Calculated 2016-2018 average from EIQ

Electric Conversion

NO_X guarantee:	0	ppm	
NO_X lb/hr:	0.00	lb/hr	
NO_X tpy:	0.00	tpy	
Total Cap Investment	$ 27,138,590		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 3,105,411		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ -		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$ 3,105,411		
Emissions Reduction:	174.53	tpy	
Cost Effectiveness:	**$ 17,792.65**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Clark TLA-10 RICE Unit 14	Interest Rate:		9.62%	<-- Company-specific interest rate as of 6/30/20
	Period:		20	years
Base Emissions				
NO_X lb/hr:		48.42	lb/hr	<-- Calculated 2016-2018 average from EIQ
NO_X tpy:		168.33	tpy	<-- Calculated 2016-2018 average from EIQ
Electric Conversion				
NO_X guarantee:		0	ppm	
NO_X lb/hr:		0.00	lb/hr	
NO_X tpy:		0.00	tpy	
Total Cap Investment	$	27,138,590		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	3,105,411		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	-		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$	3,105,411		
Emissions Reduction:		168.33	tpy	
Cost Effectiveness:	**$**	**18,447.99**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

GE Frame 5 Turbine Unit 17	Interest Rate:		9.62%	<-- Company-specific interest rate as of 6/30/20
	Period:		20	years
Base Emissions				
NO_X ppm:		54.7	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:		29.15	lb/hr	<-- From 2016 Stack Test Data
NO_X tpy:		126.82	tpy	<-- Calculated
Electric Conversion				
NO_X guarantee:		0	ppm	
NO_X lb/hr:		0.00	lb/hr	
NO_X tpy:		0.00	tpy	
Total Cap Investment	$	51,018,496		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	5,837,938		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	-		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$	5,837,938		
Emissions Reduction:		126.82	tpy	
Cost Effectiveness:	**$**	**46,031.67**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

GE Frame 5 Turbine Unit 18	Interest Rate:		9.62%	<-- Company-specific interest rate as of 6/30/20
	Period:		20	years
Base Emissions				
NO_X ppm:		48.7	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:		29.15	lb/hr	<-- From 2016 Stack Test Data
NO_X tpy:		126.61	tpy	<-- Calculated
Electric Conversion				
NO_X guarantee:		0	ppm	
NO_X lb/hr:		0.00	lb/hr	
NO_X tpy:		0.00	tpy	
Total Cap Investment	$	51,018,496		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	5,837,938		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	-		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$	5,837,938		
Emissions Reduction:		126.61	tpy	
Cost Effectiveness:	**$**	**46,108.51**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbine Unit 35	Interest Rate:		9.62%	<-- Company-specific interest rate as of 6/30/20
	Period:		20	years
Base Emissions				
NO_X ppm:		125	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:		27.72	lb/hr	<-- From 2016 Stack Test Data
NO_X tpy:		119.52	tpy	<-- Calculated
Electric Conversion				
NO_X guarantee:		0	ppm	
NO_X lb/hr:		0.00	lb/hr	
NO_X tpy:		0.00	tpy	
Total Cap Investment	$	46,037,031		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	5,267,919		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	-		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$	5,267,919		
Emissions Reduction:		119.52	tpy	
Cost Effectiveness:	**$**	**44,076.86**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbine Unit 36	Interest Rate:		9.62%	<-- Company-specific interest rate as of 6/30/20
	Period:		20	years
Base Emissions				
NO_X ppm:		122	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:		28.00	lb/hr	<-- Calculated based on NOx concentration
NO_X tpy:		117.84	tpy	<-- Calculated
Electric Conversion				
NO_X guarantee:		0	ppm	
NO_X lb/hr:		0.00	lb/hr	
NO_X tpy:		0.00	tpy	
Total Cap Investment	$	46,037,031		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	5,267,919		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	-		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$	5,267,919		
Emissions Reduction:		117.84	tpy	
Cost Effectiveness:	**$**	**44,703.67**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbine Unit 37	Interest Rate:		9.62%	<-- Company-specific interest rate as of 6/30/20
	Period:		20	years
Base Emissions				
NO_X ppm:		103	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:		22.93	lb/hr	<-- Calculated based on NOx concentration
NO_X tpy:		85.97	tpy	<-- Calculated
Electric Conversion				
NO_X guarantee:		0	ppm	
NO_X lb/hr:		0.00	lb/hr	
NO_X tpy:		0.00	tpy	
Total Cap Investment	$	46,037,031		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	5,267,919		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	-		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$	5,267,919		
Emissions Reduction:		85.97	tpy	
Cost Effectiveness:	**$**	**61,277.73**	**$/ton**	

TOTAL CAPITAL INVESTEMENT COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
CHACO GAS PLANT

Chaco Gas Plant								
Cost Estimation Methodology Used:	**EPA Air Pollution Control Cost Manual Section 5.2, Chapter 1, Table 1.3[1]**							
Unit:	**12**	**13**	**14**	**17**	**18**	**35**	**36**	**37**
Combustion Unit:	**Clark TLA-10**	**Clark TLA-10**	**Clark TLA-10**	**GE Frame 5**	**GE Frame 5**	**Mars T-15000**	**Mars T-15000**	**Mars T-15000**
Electric Infrastructure Cost:	$ 9,004,167	$ 9,004,167	$ 9,004,167	$ 11,337,500	$ 11,337,500	$ 11,337,500	$ 11,337,500	$ 11,337,500
Electric Motor/Compressor Cost:	$ 1,449,836	$ 1,449,836	$ 1,449,836	$ 8,315,233	$ 8,315,233	$ 6,396,333	$ 6,396,333	$ 6,396,333
PEC (Control System Cost*1.18):	$ 12,335,723	$ 12,335,723	$ 12,335,723	$ 23,190,225	$ 23,190,225	$ 20,925,923	$ 20,925,923	$ 20,925,923
DIC (PEC*0.85)	$ 10,485,364	$ 10,485,364	$ 10,485,364	$ 19,711,692	$ 19,711,692	$ 17,787,035	$ 17,787,035	$ 17,787,035
DC (PEC + DIC):	$ 22,821,087	$ 22,821,087	$ 22,821,087	$ 42,901,917	$ 42,901,917	$ 38,712,958	$ 38,712,958	$ 38,712,958
IC (PEC*0.35) :	$ 4,317,503	$ 4,317,503	$ 4,317,503	$ 8,116,579	$ 8,116,579	$ 7,324,073	$ 7,324,073	$ 7,324,073
Total Capital Investment (DC+IC):	**$ 27,138,590**	**$ 27,138,590**	**$ 27,138,590**	**$ 51,018,496**	**$ 51,018,496**	**$ 46,037,031**	**$ 46,037,031**	**$ 46,037,031**

[1] https://www.epa.gov/sites/production/files/2020-07/documents/cs5-2ch1.pdf

PEC - Purchased Equipment Cost	Control equipment
DIC - Direct Installation Cost	Foundation/supports, handling/erection, electrical, piping, installation of ductwork, painting
DC - Direct Cost	PEC and DIC
IC - Indirect Cost	Engineering, Construction and field expenses, contractor fees, start-up, performance test, contingencies

NMED Final Cost Evaluation
Enterprise Field Services - South Carlsbad Compressor Station

Facility Information

Enterprise - South Carlsbad Compressor Station	**Facility**
Two 1970s NG-fired CT, 4700 hp	**Units**
Units 1 and 2	**Unit IDs**
SoloNOx	**Evaluated Pollution Control**
15.0	**Post-control Emissions Rate (ppmv)***

*Per Setember 9, 2024 letter from Solar turbines

Supporting Information

2019	**Calendar year associated with cost estimates**
4328	**Maximum/Permitted Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 1	Unit 2	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Included in TCC
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	Included in TCC
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	Included in TCC
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Included in TCC
Total Capital Costs - Direct ($)	TCC	$ 900,000	$ 900,000	Enterprise Aug 2023 FFA update	
Additional Capital ($)	AC	$ 135,000	$ 135,000	-	Estimated installation costs = 15% of TCC
Total Capital Investment ($)	TCI	$ 1,035,000	$ 1,035,000	Enterprise Aug 2023 FFA update	
Interest Rate (%)	R	10.50%	10.50%	Enterprise Aug 2023 FFA update	
Useful Life (yr)	Y	20	20	Enterprise initial FFA (11.2019) and Aug 2023 FFA update	
Capital Recovery Factor	CRF	0.1215	0.1215	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 125,746	$ 125,746	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 34,171	$ 34,171	Enterprise August 2023 FFA update (2023$ converted to 2019$ using CEPCI)	Incremental annual inspection and overhaul costs
Other Indirect Annual Costs ($/yr)	OAC	$ 41,400	$ 41,400	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 201,317	$ 201,317	-	ACC + OMC
NOx Control Efficiency (%)	Eff	88%	88%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	77.2	76.9	CY 2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	77.2	76.9	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	68.0	67.7	-	PAE x Eff
2019$ Cost Effectiveness ($/ton)	**CE1**	**$ 2,960**	**$ 2,974**	-	TAC/ER
Price Index	PI	1.31	1.31	-	CEPCI 2024* / CEPCI 2019 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 3,877**	**$ 3,896**	-	CE1 x PI

NMED Final Cost Evaluation
Enterprise Field Services - South Carlsbad Compressor Station

Facility Information

Enterprise - South Carlsbad Compressor Station	**Facility**
Two 1970s NG-fired CT, 4700 hp	**Units**
Units 1 and 2	**Unit IDs**
SCR	**Evaluated Pollution Control**

Supporting Information

2024	**Calendar year associated with cost estimates**
41.2	**Heat Input Capacity (MMBtu/hr/unit, calculated)**

Economic Evaluation

Cost Component		Unit 1	Unit 2	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	A retrofit factor of 1.1 was used in the EPA SCR Tool to account for the additional capital costs anticipated to create physical space for the SCR system. This factor was selected based on Enterprise's recurring assertion that the current layout of the existing building can not accommodate the physical space needed for SCR. Aerial photos provided by Enterprise suggest there is space for SCR if building modifications are made.
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	$ -	-	
Total Capital Costs - Direct ($)	TCC	$2,851,414	$ 2,851,414	EPA SCR Tool (2024$)	
Additional Capital ($)	AC	$ -	$ -	See Note	
Total Capital Investment ($)	TCI	$ 2,851,414	$ 2,851,414	-	TCC + AC
Interest Rate (%)	R	10.50%	10.50%	Enterprise August 2023 FFA update	
Useful Life (yr)	Y	20	20	Default per EPA Cost Manual	
Capital Recovery Factor	CRF	0.1215	0.1215	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 346,428	$ 346,428	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 51,041	$ 50,891	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 2,799	$ 2,799	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 400,268	$ 400,118	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	80%	80%	EPA SCR Tool	Consistent with EPA and industry documentation
Baseline Actual NOx Emissions (ton/yr)	BAE	77.2	76.9	CY 2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	77.2	76.9	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	61.8	61.5	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 6,481**	**$ 6,502**	-	TAC/ER

NMED Final Cost Evaluation
Enterprise Field Services - South Carlsbad Compressor Station

Facility Information

Enterprise - South Carlsbad Compressor Station	**Facility**
Two 1970s NG-fired CT, 4700 hp	**Units**
Units 1 and 2	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
15.0	**Post-control Emissions Rate (ppmv)**

Supporting Information

2023	**Calendar year associated with cost estimates**
4328	**Maximum/Permitted Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 1	Unit 2	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 14,023,239	$ 14,023,239	9/8/20 info from El Paso Natural Gas (2020$ converted to 2023$ with CEPCI)	All-in estimate ($/HP) x Maximum Capacity (HP); Using EPNG's $2418/hp cost metric as Enterprise did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered CT.
Interest Rate (%)	R	10.50%	10.50%	Enterprise Aug 2023 FFA update	
Useful Life (yr)	Y	30	30	ERG experience based on discussions with CT manufacturers	
Capital Recovery Factor	CRF	0.1105	0.1105	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 1,549,967	$ 1,549,967	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 44,764	$ 44,764	Enterprise Aug 2023 FFA update	Incremental annual inspection and overhaul costs
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 1,594,731	$ 1,594,731	-	ACC + OMC
NOx Control Efficiency (%)	Eff	88%	88%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	77.2	76.9	CY 2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	77.2	76.9	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	68.0	67.7	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 23,446**	**$ 23,561**	-	TAC/ER
Price Index	PI	1.00	1.00	-	CEPCI 2024* / CEPCI 2023 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 23,446**	**$ 23,561**	-	CE1 x PI

NMED Final Cost Evaluation
Enterprise Field Services - South Carlsbad Compressor Station

Facility Information

Enterprise - South Carlsbad Compressor Station	**Facility**
Two 1970s NG-fired CT, 4700 hp	**Units**
Units 1 and 2	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (ppmv)**

Additional Information

2023	**Calendar year associated with cost estimates**
4328	**Maximum/Permitted Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 1	Unit 2	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Enterprise provided a cost estimate for electrification using EPA Cost Control Manual Section 5.2, which pertains to acid gas scrubbers. As this is not applicable to replacement with EMD, a Total Capital Cost metric of $2,084 (2023$/hp) was calculated using detailed cost information provided by other facilities. The TCI figure assumes no costs associated with substation or distribution line upgrades. This assumption underestimates costs given that Enterprise indicated in its August 2023 update that utility infrastructure upgrades would be needed to support electrification at all three of its facilities.
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ 9,019,552	$ 9,019,552	See Note	
Additional Capital ($)	AC	$ -	$ -	-	
Total Capital Investment ($)	TCI	$ 9,019,552	$ 9,019,552	See Note	
Interest Rate (%)	R	10.50%	10.50%	Enterprise Aug 2023 FFA update	
Useful Life (yr)	Y	25	25	Consistent with other FFAs	
Capital Recovery Factor	CRF	0.114	0.114	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 1,032,101	$ 1,032,101	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 868,776	$ 862,984	-	AED + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 1,737,553	$ 1,725,968	ERG calculation	Assumes unit at 60% load, 95% efficiency and a $0.10/kWh price
Associated non-electricity O&M ($/yr)	AOM	$ -	$ -	Engineering judgment	Assumed to be negligible
Annual Fuel Credit ($/yr)	AFC	$ (868,776)	$ (862,984)	ERG calculation	Assumes fuel savings is 50% of AED
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 1,900,878	$ 1,895,085	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	100%	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	77.2	76.9	CY 2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Enterprise
Projected Actual Emissions (ton/yr)	PAE	77.2	76.9	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	77.2	76.9	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 24,623**	**$ 24,635**	-	TAC/ER
Price Index	PI	1.00	1.00	-	CEPCI 2024* / CEPCI 2023 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 24,623**	**$ 24,635**	-	CE1 x PI

NMED Final Cost Evaluation
Enterprise Field Services - South Carlsbad Compressor Station

Unit 1: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.1

* NOTE: You must document why a retrofit factor of 1.1 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	41.2	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	340,629,292	scf/Year
	8524	hr/yr
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 3070 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.44	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.09	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	10.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 1: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	41	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	350,060,136	scf/Year
Actual Annual fuel consumption (Mactual) =		340,629,292	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.973	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8524	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	14.48	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	61.71	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.12	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.10	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3007	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	168.40	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	6	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	19	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	900	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.1215

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	24.39	kW

Unit 1: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,851,414	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$51,041 in 2024 dollars
Indirect Annual Costs (IDAC) =	$349,246 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$400,287 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$14,257 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$11,689 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$20,791 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$4,304 in 2024 dollars
Direct Annual Cost =		$51,041 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,799 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$346,447 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$349,246 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$400,287 per year in 2024 dollars
NOx Removed =	62 tons/year
Cost Effectiveness =	$6,486 per ton of NOx removed in 2024 dollars

NMED Final Cost Evaluation
Enterprise Field Services - South Carlsbad Compressor Station

Unit 2: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.1

* NOTE: You must document why a retrofit factor of 1.1 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	41.2	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	338,351,503	scf/Year
	8467	hr/yr
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3070	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.44	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.09	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	10.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 2: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	41	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	350,060,136	scf/Year
Actual Annual fuel consumption (Mactual) =		338,351,503	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.967	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8467	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	14.56	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	61.64	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.12	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.10	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3007	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	168.53	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	6	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	20	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	900	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.1215

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	24.39	kW

Unit 2: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,851,414	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$50,891 in 2024 dollars
Indirect Annual Costs (IDAC) =	$349,246 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$400,137 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$14,257 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$11,675 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$20,652 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$4,308 in 2024 dollars
Direct Annual Cost =		$50,891 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,799 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$346,447 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$349,246 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$400,137 per year in 2024 dollars
NOx Removed =	62 tons/year
Cost Effectiveness =	$6,492 per ton of NOx removed in 2024 dollars

Enterprise Products

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS HOLDINGS LLC
(General Partner)

ENTERPRISE PRODUCTS OPERATING LLC

October 30, 2019

Federal Express

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

RE: Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program
Enterprise Field Services, LLC
South Carlsbad Compressor Station

Mr. Singleton:

Please find enclosed Enterprise Field Services, LLC ("Enterprise") analysis of control measures for the South Carlsbad Compressor Station in Eddy County, New Mexico, as requested by the NMED by letter dated July 18, 2019.

Enterprise's submittal of a similar control measure analysis for the Chaco Gas Plant and Blanco C&D Compressor Station will follow by November 15, 2019, per the NMED's October 29 letter granting additional time for Enterprise to submit the analysis for those facilities.

In addition, Enterprise may supplement its submittal of the control measure analyses with legal comments, which would be integral to Enterprise's position on the appropriateness of the control measures analyzed for all three facilities. For convenience and to avoid duplication, we would include the legal comments with our November 15 submittal.

If you have questions or require additional information, please contact me at (713) 381-6698 or by email at rmhavalda@eprod.com or Bradley Cooley at (713) 381-5828.

Thank you,

Robert Havalda, P.E
Senior Engineer, Environmental

Bradley J. Cooley, P.E.
Senior Manager, Environmental

/kna
Attachment

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REGIONAL HAZE FOUR-FACTOR ANALYSIS

Enterprise Field Services, LLC, South Carlsbad Compressor Station

Prepared By:

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November 2019

Project 193201.0181

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1. EXECUTIVE SUMMARY

In the 1977 amendments to the Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977. EPA has since amended the RHR in certain respects, most recently on January 10, 2017.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, the states, among other things:

(A) *"[E]valuate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment" and "include in [the state's] implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy."* 40 CFR 51. 308(f)(2)(i). This is known as a four-factor analysis.

(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(f)(1). The uniform rate of progress or improvement is sometimes referred to as the "URP" or the glidepath and is considered in the process of developing the state's Long Term Strategy (LTS).

The second implementation, or planning, period (2019-2028) for national regional haze efforts is currently underway. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural or biogenic and manmade or anthropogenic sources of emissions. Using a Photochemical Grid Model (PGM), the Western Regional Air Partnership (WRAP), in coordination with the EPA, is tasked with comparing anthropogenic source contributions against natural background concentrations. EPA has issued guidance to states for development of State Implementation Plans (SIPs) for regional haze requirements for the second planning period.[1,2]

[1] U.S. EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, EPA-457/B-19-003 (Aug. 2019); U.S. EPA, Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program, EPA-454/R-18-010 (Dec. 2018).

[2] U.S. EPA, Technical Support Document for EPA's 2028 Regional Haze Modeling (Sept. 2019).

Pursuant to 40 CFR 51.308(f)(2), the states are responsible for identifying sources that contribute to the most impaired days in the Class I areas. To accomplish this, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for Title V sources and screened each facility's potential impact on visibility in Class I areas using a "Q/d" analysis, where "Q" is the magnitude of emissions that could impact ambient visibility and "d" is the distance of a facility to a Class I area. The NMED defined a source with a high potential for visibility impairment as one with a "Q/d" greater than 5.5. From this analysis, 24 facilities were identified by the NMED. On July 18, 2019, the NMED informed Enterprise Field Services, LLC (Enterprise) that its facility, the South Carlsbad Compressor Station, was identified as one of the sources potentially contributing to regional haze at the Carlsbad Caverns Class I area.

In coordination with guidance provided by WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. The NMED's July 18, 2019 notification letter to Enterprise specifies that any equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The equipment at the facility that is subject to this analysis, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant are reported in Table 1.

Table 1. Summary of Equipment and Applicability to a Four-Factor Analysis

Equipment	NO_X Hourly PTE (lb/hr)	NO_X Annual PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
Solar Centaur T4702 Turbines (Units 1 and 2)	27.0	90.8	Yes	<1.0	2.2	No

Once the applicability of process equipment and pollutants has been determined, potential retrofit control technologies must be identified. One of the reference sources that the NMED has suggested consulting is the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC). In order to determine the most relevant and current retrofit controls available, the RBLC was queried for the previous ten years. Summaries of the result of this search are provided and discussed in Section 2 of this report. The facility engineers then reviewed the list of available retrofit technologies and performed a technical feasibility assessment for each control option. The four-factor analysis was then conducted for those controls that are technically feasible at the South Carlsbad Compressor Station site.[3]

Based on the technical and economic factors summarized in this report, Enterprise has provided recommendations for the NMED in its efforts to design, in coordination with WRAP, the SIP under the Regional Haze Rule.

[3] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

2.1. COMBUSTION TURBINES

Two of South Carlsbad's natural gas-fired turbines (Units 1 and 2) are subject to this four-factor analysis due to their NO_X emission rates.

2.1.1. Combustion Turbine Background

A gas turbine is an internal combustion engine that operates with a rotary, rather than reciprocating, motion and is composed of three primary components: a compressor, a combustor, and a power turbine. The compressor draws in ambient air and compresses it up to 30 times the ambient pressure, then directs it into the combustor, where fuel is introduced, ignited, and burned. Exhaust gas from the combustor is then diluted with additional air and sent to the power turbine at temperatures of up to 2600 °F. The hot exhaust gas expands in the power turbine section, generating energy in the form of shaft horsepower.[4]

The treatment of the exhaust gases exiting the turbine dictates the cycle designation of these units. The heat content can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).[5] The units at South Carlsbad are regenerative cycle turbines, which are essentially simple cycle gas turbines with an added heat exchanger.

NO_X is formed via three fundamentally different mechanisms. The principal NO_X formation mechanism, thermal NO_X, arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion. Most thermal NO_X forms in the highest temperature regions of the combustion chamber. The second NO_X formation mechanism, fuel NO_X, arises from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. The final NO_X formation mechanism, prompt NO_X, arises from early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The significance of prompt NO_X is negligible in comparison to thermal and fuel NO_X. Fuel NO_X will also be negligible for South Carlsbad's turbines assessed here, as these combustion turbines fire natural gas, which contains a negligible amount of nitrogen compounds. Therefore, this analysis will focus on thermal NO_X.

The PTE from each turbine is reported in the facility's New Source Review (0220-M10R1) and Title V (P130-R3) permits and is summarized in Table 1.

2.1.2. Potential NO_X Controls for a Combustion Turbine

There are three general methods of controlling NO_X emissions from gas turbines; (1) wet controls, which use steam or water injection to reduce combustion temperatures and NO_X formation, (2) dry controls that use

[4] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines."

[5] Ibid.

advanced combustor design to suppress NO_X formation, and (3) post-combustion, catalytic controls to selectively reduce NO_X.[6]

The categories of retrofit control equipment identified for combustion turbines during a comprehensive review of the RBLC are reported in Table 2. A detailed discussion, including a description, the technical feasibility, and the anticipated performance of each control, is provided below.

Table 2. Potential Control Options for Combustion Turbines

Control Equipment	Technically Feasible	NO_X Control Efficiency
Good Combustion Practices	**Base Case**	**N/A**
SoloNO$_X$	**Yes**	**64%**
Water/Steam Injection	**No**	**N/A**
Selective Catalytic Reduction	**No**	**N/A**

2.1.2.1. Good Combustion Practices

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. Applying concepts from engineering knowledge, experience, and the manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for the equipment involved, and using pipeline quality natural gas. If good combustion practices are maintained, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from combustion turbines; therefore, it has been determined that this method of NO_X control is feasible for the units at South Carlsbad. However, these practices are currently in use at South Carlsbad, as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices has been included in this report.

2.1.2.2. SoloNOx

The key factors in thermal NO_X formation are the combustion temperature and the residence time of fuel in the combustor. SoloNO$_X$ reduces NO_X emissions by reducing both of these factors. Ultimately, this is accomplished by optimizing the air-to-fuel ratio. According to information received from Solar, SoloNOx can reduce NO_X exhaust concentrations to 25 ppmv on the Centaur T4702 units.

2.1.2.3. Water/Steam Injection

Water or steam injection is a technology that has been demonstrated to effectively suppress NO_X emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the

[6] Ibid.

latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.

Enterprise received information from Solar stating that the Centaur T4702 units cannot support steam injection and that they do not offer water injection equipment. They also stated that, while a third-party vendor may be able to develop water injection controls for the turbines, that this control may impose a risk of damaging this equipment and that any damage caused by water injection would not be covered under the equipment's warranty. Based on the statements from Solar regarding the installation of water and steam injection, Enterprise does not consider this control technically feasible.

2.1.2.4. Selective Catalytic Reduction Systems

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust stream at a point downstream of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[7] The chemical reactions for this process are shown in the equations below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O \quad \text{(Equation 1)}$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O \quad \text{(Equation 2)}$$

An SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and electronic control system. The electronic controls regulate the quantity of reagent injected as a function of turbine load, speed, and temperature, so NO_X emissions reductions can be achieved. The lifespan of the catalyst is primarily determined by poisoning of active sites by flue gas constituents, thermal sintering, or compacting, of active sites due to high temperatures in the reactor; fouling caused by ammonia-sulfur salts and particulate matter in the gas; and erosion due to high gas velocities.[8]

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as ammonia slip. Unreacted ammonia in the exhaust can form ammonium sulfates, which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.[9]

In order for the SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 °F and 850 °F), dependent on the material of the catalyst. Exhaust gas temperatures greater than the upper limit will cause the NO_X and ammonia to pass through the catalyst unreacted.[10]

The South Carlsbad facility was designed and constructed without considerations for the installation of SCRs in mind. An onsite evaluation was conducted at the South Carlsbad facility during which measurements were taken of any feasible locations for SCR equipment. These measurements took into consideration the amount of buffer space needed to maintain accessibility to equipment and to not compromise worker safety. Based on size estimates of SCR units provided by CECO-Peerless, Enterprise determined that it is not possible to install these units.

---

[7] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
[8] Ibid.
[9] Ibid.
[10] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines."

Enterprise has evaluated the costs of implementing the technically feasible control technologies at South Carlsbad as thoroughly as possible in the time provided to complete this assessment. The cost estimates presented below are calculated according to methods and recommendations described in the EPA Air Pollution Control Cost Manual.[11]

Emission inventory data and stack test data from 2016 were used to assess the baseline emissions for these units.

3.1. TURBINE CONTROLS

Table 3. Cost Analysis Summary of Technically Feasible Controls for Turbines

Control Equipment	Unit No.	Cost Effectiveness	Cost Factors
SoloNOx	1	$8,583.57 per ton	Equipment costs, routine overhaul and labor costs
	2	$6,629.15 per ton	

3.1.1. SoloNOx

For the Solar Centaur T4702 turbines (Units 1 and 2), Enterprise received a capital cost estimate from Solar for the SoloNOx control equipment. Total installed cost is estimated to be $1,342,700 per unit. Based on additional information from Solar regarding overhaul costs for these units, Enterprise estimates other associated annual operating costs to be approximately $37,756 per unit. The expected useful life of this control equipment is 20 years. Based on the target NOx exhaust concentration of 25 ppm provided by Solar, the expected control efficiencies associated with SoloNOx are 64% and 66% for Units 1 and 2, respectively. The control would reduce the annual NO_X emissions of unit 1 and 2 by 20.8 tons and 26.9 tons, respectively. This results in an amortized cost effectiveness of $8,583.57 and $6,629.15 per ton of NO_X reduction for Units 1 and 2, respectively.

[11] U.S. EPA, "Air Pollution Control Cost Manual," available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

4. TIME NECESSARY FOR COMPLIANCE

The second factor in this analysis is the time necessary for compliance. Consideration of this factor involves estimating the time required for a source to implement a potential control measure. This information is provided here in order to advise the NMED of Enterprise's projection of a reasonable compliance timeline based on the equipment and site-specific considerations that could affect the time necessary to comply.

Enterprise estimates that up to 3 to 4 years will be needed to budget, design, procure, and construct any of the control measures discussed in this report.

5. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS OF COMPLIANCE

5.1. TURBINE CONTROLS

5.1.1. SoloNO$_X$

This section addresses the potential energy and non-air environmental impacts that installation of the technically feasible control options impose on a source. The consideration of energy impacts involves assessing the impact of a control measure on the energy that is consumed by the source. Non-air environmental impacts are assessed based on the effect of the control on non-air environmental media. Some examples of non-air environmental impacts include water resource depletion, solid waste generation, increased noise and odor pollution, and increased land usage.

There are no anticipated unique or site-specific energy or non-air quality environmental impacts from installation and operation of SoloNO$_X$ on the South Carlsbad turbines.

6.1. TURBINE CONTROLS

6.1.1. SoloNOx

The anticipated remaining useful life of each source is addressed here for the NMED's consideration. The assessment of this factor involves estimating how long the sources analyzed will remain in operation and the lifetime of potential control measures, accounting for equipment and site-specific limitations.

40 CFR Part 51, Appendix Y includes guidance on the characterization of this factor, stating that the remaining useful life of a source will typically be longer than the useful life of the emission control system. Therefore, it is appropriate to annualize compliance costs based on the useful life of the control equipment, rather than the life of the source.[12]

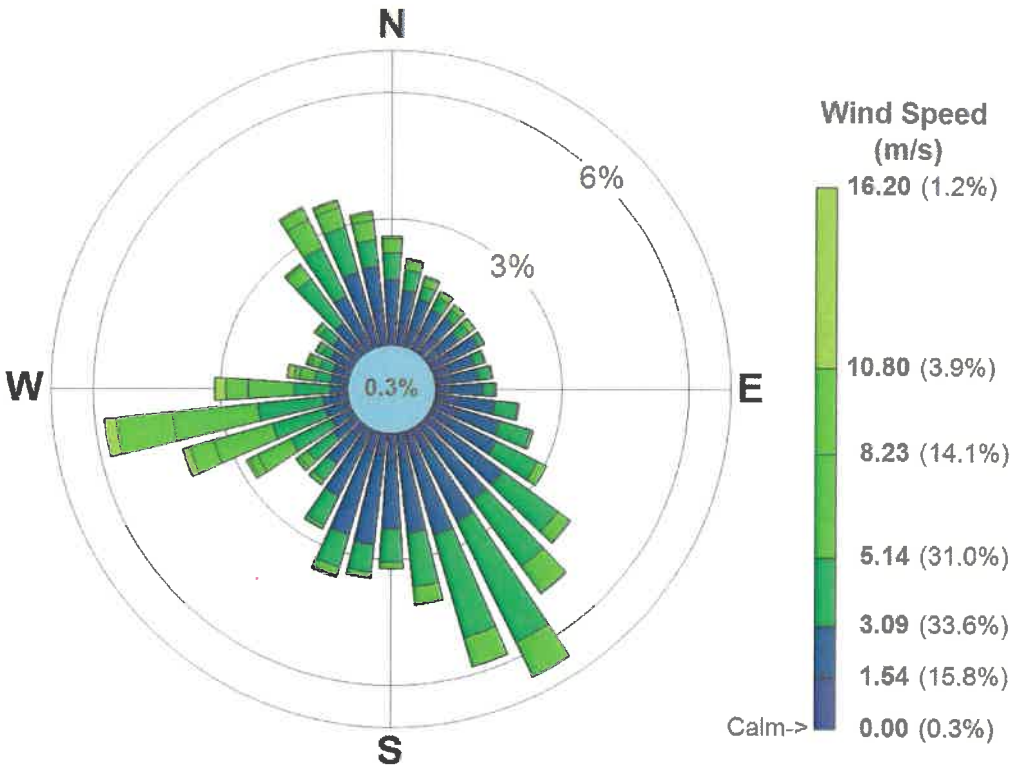
The estimated useful life of a SoloNO$_X$ control is 20 years. This estimate has been incorporated in the cost analysis section to calculate the total annualized cost of the control.

[12] 40 CFR 51, Appendix Y, Section II.B.4.f

Enterprise does not believe implementing any of the evaluated controls would improve visibility in nearby Class I areas based on climatological data and ambient pollutant data.

The South Carlsbad Compressor Station is located approximately 16.2 miles from the Carlsbad Caverns Class I area at a wind vector range of approximately 60 degrees to 70 degrees (NE). According to 2017 meteorological data collected in Carlsbad presented in Figure 1, wind only blows from this direction at a frequency of 1.4% or approximately 120 hours per year. Moreover, over the 16 miles of transport, pollutants would undergo significant dispersion. While full dispersion and photochemical modeling would need to be conducted to more accurately evaluate South Carlsbad's impact, based on this evidence, the facility's impact on visibility is likely insignificant.

Figure 1. A Windrose Reporting 2017 Wind Direction and Speed in Carlsbad, NM



Additionally, according to aerosol composition data reported on visibility impaired periods at the Carlsbad Caverns National Park IMPROVE Monitor, the main contributing pollutant to regional haze is ammonium sulfate.[13] Therefore, installing NO_X controls on the units at South Carlsbad would not significantly improve visibility.

Based on a comprehensive review of the RBLC, available literature, and manufacturer's input on the available control technologies for the natural-gas fired turbines located at the South Carlsbad Compressor Station, Enterprise has determined that it is not technically feasible or cost effective to implement any controls on equipment at this time, particularly given the expected insignificant impact at Carlsbad Caverns National Park.

[13] 2007 to 2017 Regional Haze Trends (https://www.env.nm.gov/wp content/uploads/sites/2/2019/02/2000_2017 trends-in-NM.pdf

8. SUPPORTING DOCUMENTATION

Enterprise Field Services, LLC

South Carlsbad Compressor Station

Solar Centaur T4702 Turbines Unit 1	Interest Rate:	8.38%	
	SoloNO$_x$ Period:	20 years	
Base Emissions			
NO$_x$ ppm:	69.6	ppm	<-- From 2016 Stack Test Data
NO$_x$ lb/hr:	7.59	lb/hr	<-- From 2016 Stack Test Data
Hours of Operation:	8544	hrs	<-- From 2016 Emission Inventory Data
NO$_x$ tpy:	32.42	tpy	<-- Calculated
SoloNO$_x$			
NO$_x$ guarantee:	25	ppm	<-- From Solar
NO$_x$ lb/hr:	2.73	lb/hr	
NO$_x$ tpy:	11.64	tpy	
Total Cap Investment	$ 1,342,700		<-- Equipment, installation, engineering, and inspection costs
Annualized TCI:	$ 140,631		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 37,756		<-- Routine overhaul and labor costs
Total Annual Costs:	$ 178,387		
Emissions Reduction:	20.78	tpy	
Cost Effectiveness:	**$ 8,583.57**	**$/ton**	

Enterprise Field Services, LLC

South Carlsbad Compressor Station

Solar Centaur T4702 Turbines Unit 2	Interest Rate:	8.38%		
	$SoloNO_X$ Period:	20	years	
Base Emissions				
NO_X ppm:		73.4	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:		9.55	lb/hr	<-- From 2016 Stack Test Data
Hours of Operation:		8544	hrs	<-- From 2016 Emission Inventory Data
NO_X tpy:		40.80	tpy	<-- Calculated
$SoloNO_X$				
NO_X guarantee:		25	ppm	<-- From Solar
NO_X lb/hr:		3.25	lb/hr	
NO_X tpy:		13.89	tpy	
Total Cap Investment	$	1,342,700		<-- Equipment, installation, engineering, and inspection costs
Annualized TCI:	$	140,631		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	37,756		<-- Routine overhaul and labor costs
Total Annual Costs:	$	178,387		
Emissions Reduction:		26.91	tpy	
Cost Effectiveness:	**$**	**6,629.15**	**$/ton**	

Four Factor Analysis for Natural Gas Fired Turbines – NO_x

	Control Technology	Selective Catalytic Reduction (SCR)[a]	Water/Steam Injection[b]	Improved Combustion Technology (Low-NO_x Combustors, Ultra-Low NO_x Combustors and other improved combustion technology)	Good Combustion Technique
IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	A nitrogen-based reagent (e.g., ammonia, urea) is injected into the exhaust stream downstream of the combustion unit. The reagent reacts selectively with NO_x to produce molecular N_2 and water in a reactor vessel containing a metallic or ceramic catalyst.	Injected water/steam acts as a heat sink, lowering combustion zone peak temperatures, resulting in a decrease in thermal NO_x.	Low-NO_x burners (or SoloNOx) employ multi-staged combustion to inhibit the formation of NO_x. Primary combustion occurs at lower temperatures under oxygen-deficient conditions; secondary combustion occurs in the presence of excess air.	NO_x emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. Primary combustion occurs at lower temperatures under oxygen-deficient conditions. By following EPA's "Good Combustion Practices" guidance document, good combustion practices can be maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices the unit will operate as intended with the optimal NO_x emissions.
	Other Considerations	Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as "ammonia slip." Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.	Results in a small efficiency penalty but an increase in power output. May increase CO and VOC emissions. Not available in certain models.	N/A	N/A
	RBLC Database Information	Included in RBLC for the control of NO_X emissions from combustion turbines.	Included in RBLC for the control of NO_X emissions from combustion turbines.	Included in RBLC for the control of NO_X emissions from combustion turbines.	Included in RBLC for control of NOx emissions from combustion turbines.
ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	Feasibility Discussion	Technically infeasible due to space limitations a the facilty.	Technically infeasible since this option is not available for the turbine model.	Technically feasible.	Base case.

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
b. U.S. EPA, AP-42 Section 3.1, "Stationary Gas Turbines"
c. California EPA, Air Resources Board, "Section 311 - Non-Selective Catalytic Reduction and Other NO_x Controls," http://www.arb.ca.gov/cap/manuals/cntrldev/sncr_etc/311nscr.htm



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February 13, 2020

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Return Receipt Requested

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505

Re: NMED Follow-Up Letter Response
Regional Haze Four-Factor Analysis
Enterprise Field Services, LLC
South Carlsbad Compressor Station

Mr. Singleton:

Enterprise Field Services, LLC (Enterprise) submits herein to the New Mexico Environment Department (NMED) the enclosed responses to the follow-up questions contained in NMED correspondence dated December 23, 2019 for the Regional Haze Four-Factor Analysis submitted for the Enterprise South Carlsbad Compressor Station located in Eddy County, New Mexico.

Enterprise and Solar consider the information included in Appendix B of the enclosed response to be confidential business information (CBI) and request that it be treated as such to the full extent applicable.

Should you have questions or require further information regarding this submittal, please contact Tucker Jacobson at (713) 381-4313 (wtjacobson@eprod.com) or Bradley Cooley at (713) 381-5828.

Thank you,
Enterprise Field Services, LLC

W. Tucker Jacobson
Scientist, Senior Environmental

Bradley J. Cooley, P.E.
Senior Manager, Permitting

/bjm
Enclosure

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REGIONAL HAZE FOUR-FACTOR ANALYSIS
NMED FOLLOW-UP LETTER RESPONSE
Enterprise Field Services, LLC, South Carlsbad Compressor Station

Prepared By:

Adam Erenstein – Manager of Consulting Services
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February 2020

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The NMED posed the following questions regarding the emissions control options Enterprise presented for the two (2) Solar Centaur T4702 Combustion Turbines located at the South Carlsbad Compressor Station.

1. SELECTIVE CATALYTIC REDUCTION (SCR) TECHNOLOGY

a. *You rejected consideration of SCR technology on account of space considerations; please provide more details on the specific dimensions and space required for the installation of SCR technology.*

Response: Enterprise received information from CECO-Peerless (Natalie Boone) on October 17, 2019, which stated that an area of approximately 40' by 20' is required for an SCR unit. This correspondence is included in Appendix B. As mentioned in our original report, space at the South Carlsbad Compressor Station is restricted. We have also included an aerial image in Appendix A of the facility with measurement overlays to demonstrate that the limited space precludes the option of installing an SCR.

b. *Please also provide an estimated NO_X control efficiency.*

Response: As discussed above, space limitations at the South Carlsbad Compressor Station would preclude the installation of an SCR, and the control technology is therefore technically infeasible, the control efficiency was not estimated. However, based on information provided in AP-42 Section 3.1.4.3, an SCR can control NO_X emissions from turbines with a minimum efficiency of approximately 65%.[1]

2. COST EFFECTIVENESS

a. *Please provide a vendor quote from Solar Turbines for the SoLoNO$_X$ packages.*

Response: A vendor quote from Solar for the SoloNO$_X$ conversion is attached. There are two components of the total cost considered: (1) the capital cost of the SoloNO$_X$ unit (which includes equipment cost from Solar, installation, engineering, and inspection) and (2) the incremental annual overhaul costs. The incremental annual overhaul costs are based on hourly overhaul rates for the gas producer and power turbine, which differ for units that are operating with or without SoloNO$_X$. This information was provided by Solar on October 22, 2019. The capital and overhaul costs are amortized with the specified interest rate to calculate an annualized total capital investment. This information is submitted with this response in Appendix B.

3. EMISSIONS DATA

a. *Adjacent to the turbine NOx emissions lb./hr. and ton/year (tpy) data in your 4- Factor analysis for SoLoNOx implementation is the statement, "from 2016 stack test data". Your 2016 Emissions Inventory submittal, however, does not match the data presented in your analysis (Unit 1: 7.59 lb./hr., 32.42 tpy; Unit 2: 9.55 lb./hr., 40.80 tpy). Further observation of your 2016-2018 Emissions Inventory submittals shows numerous stack test results for the years 2014-2018, none of which matches the lb./hr. values you used in the analysis. Please clarify.*

Response: The stack test conducted in 2016 at the facility which references the emissions is included with this submission. The stack tests are the most accurate representation of engine

[1] AP-42 Section 3.1.4.3 Stationary Gas Turbines, Control Technologies, Catalytic Reduction System.

emissions during 2016. These emissions, along with the hours of operation of each unit recorded that year, were used to represent the baseline emissions reported in the four-factor analysis report. The 2016 stack test data is included in Appendix C.

4. OTHER CONTROL OPTIONS

a. Have you considered other options not otherwise listed in your 4-Factor Analysis?

i. Staged Combustion

Response: AP-42 Section 3.1.2 provides a technical background on turbine combustion. The second paragraph of that section describes lean-premixed staged combustion.[2] That paragraph defines lean-premixed combustion as a synonym for dry low NO_X. SoloNO_X is Solar's proprietary dry low NO_X combustor, which would be synonymous with this option. If such a technology were to be implemented, it would not be appropriate to use a third-party vendor for Solar turbines. The SoloNO_X burners are specifically designed to work effectively with Solar turbines and have been widely implemented on Solar's units. While it may be possible to install a third-party burner on Solar turbines, the performance cannot be guaranteed and, as stated by Solar in correspondence dated October 21, 2019 (Attachment B), such a modification could void the turbines' warranty should damage be caused to the unit by third-party equipment.

ii. Ultra-Lean Combustion

Response: Ultra-lean combustion is informally defined as dry low NO_X technology that can achieve relatively low NO_X emissions compared to dry low NO_X. However, there is no formal definition of this technology that clearly delineates ultra-low NO_X or ultra-lean combustion from lean combustion. As part of the original four-factor analysis, Enterprise requested information on the most effective SoloNOx units available and used the information it received in preparing the analysis.

iii. Water-Steam Injection

Response: As discussed in Enterprise's original submission, and as Solar stated in correspondence dated October 21, 2019 (Appendix B), Solar does not offer water injection on the Centaur T4702 turbine. As noted in the correspondence, it may be possible to install a third-party water-steam injection system on Solar turbines, but such a modification could void the turbines' warranty should damage to the unit be caused by the third-party equipment.

iv. Post-Combustion other than SCR (e.g., XONON, SCONO$_X$, NSCR).

Response: XONON is not a post-combustion technology. The XONON combustor is completely contained within the combustion chamber of the turbine. As stated in the US EPA Environmental Technology Verification report, "The design of each XONON™ combustor is customized to the particular turbine model and operating conditions of the application and would typically be defined through a collaborative effort with the manufacturer of the turbine to integrate the hardware into the design."[3] Moreover, the Air Pollution Training Institute Manual for Controlling NO_X Formation in Gas Turbines states that, "Both GE and Solar Turbines have successfully

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[2] AP-42 Section 3.1.2 Stationary Gas Turbines, Process Description.

[3] Environmental Technology Verification Report – NO_X Control Technologies: Catalytica Combustion Systems, Inc. Xonon™ Flameless Combustion System, at p. 2 (December 2000). https://archive.epa.gov/nrmrl/archive-etv/web/pdf/05_vr_xonon.pdf

operated on a 7.5 MW and a 10 MW engine using the XONON combustion system. Both engines demonstrated performance at less-than 2.5 ppmvd at 15% O2, but neither has yet made them commercially available, and it is not likely that they will."[4]

SCONOx was not identified in an exhaustive query of the RACT/BACT/LAER Clearinghouse and was not considered to be a widely implemented technology. Therefore, this technology was not considered. AP-42 Section 3.1.4.4 also states that the limited emission data available for SCONOx units cannot be used to robustly verify the manufacturer's claims for these units. Moreover, the technology is referred to as a "niche" technology, catering to a narrow range of turbines, in a DOE technical document evaluating the costs of NOx controls for turbines.[5] In this cost analysis, the cost per ton of NO_X controlled for the class of turbines installed at the South Carlsbad Compressor Station was greater than $16,000 (Table A-1). As that table in the cost anslysis indicates, this technology is only relatively cost effective for turbines of at least 150 MW, or those typically used for power generation.

NSCRs were not identified in either the RBLC or AP-42 Section 3.1 as a control option for turbines and were therefore not considered.[6]

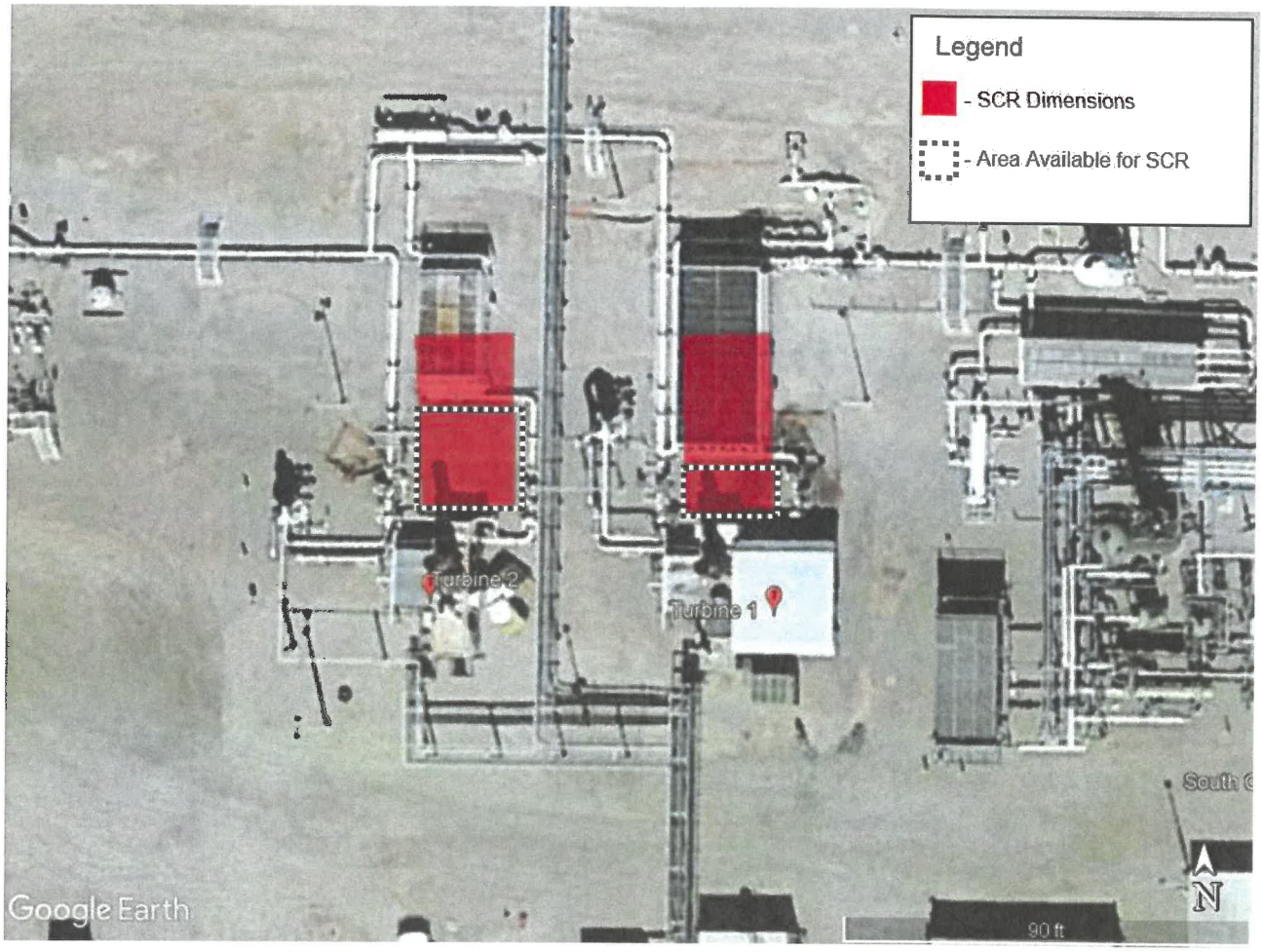
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[4] Air Pollution Training Manual Chapter 7 – Controlling NO_X Formation in Gas Turbines, at p. 7-7 (September 2009). https://www.apti-learn.net/lms/register/display_document.aspx?dID=39

[5] Cost Analysis of NO_X Control Alternatives for Stationary Gas Turbines, at p. 3-11, Contract No. DE-FC02-97CHIO877, prepared for the DOE. https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf

[6] AP-42 Section 3.1.4.3 Stationary Gas Turbines, Control Technologies, Catalytic Reduction Systems.

APPENDIX A: AERIAL MAP WITH SCR DIMENSIONS



REFER TO CONFIDENTIAL BUSINESS INFORMATION (CBI) ATTACHMENT

APPENDIX C: 2016 STACK TEST DATA

Summary of Results
South Carlsbad Compressor Station, Unit #1

Company: Enterprise Field Services
Location: South Carlsbad Compressor Station
Source: Solar Centaur 40-T4702 SN: OHD10C7915
Engine Site Rating: 3609 Hp @ 15000 RPM
Technician: JC,FC
Sample System #: 1

Test Run Number	*1*	*2*	*3*	
Emissions Unit	**1**	**1**	**1**	
Date	1/20/16	1/20/16	1/20/16	
Start Time	7:53	8:18	8:43	
Stop Time	8:13	8:38	9:03	
Engine/Compressor Operation				
Turbine Load (%)	**94.7**	**95.0**	**95.2**	
Gas Producer Speed (%)	94.7	95.0	95.2	
Power Turbine Speed (%)	82.7	83.0	83.1	
Engine Horsepower (Hp)	3418	3429	3436	
Engine Compressor Discharge, PCD (psig)	104	105	105	
Fuel Valve Output (%)	59.9	61.3	60	
Suction Pressure (psig)	419	423	424	
Discharge Pressure (psig)	659	712	712	
Suction Temperature (°F)	98	98	99	
Discharge Temperature (°F)	123	124	177	
Air Inlet Temperature (T1) (°F)	40.2	39	43.2	
Average Exhaust Temperature (T5) (°F)	1080	1047	1090	
Compressor Throughput (MCFD)	72	72	72	
Fuel Data				
Measured Fuel Consumption (MSCFD)	788	788	788	
Calculated Fuel Consumption (SCFH)	17905	17905	17905	
O2 F-Factor (DSCF/MMBtu, HHV basis)	8696	8696	8696	
Fuel Heating Value (Btu/SCF, HHV)	1155	1155	1155	
BHp Specific Fuel Rate (Btu/Hp-hr, HHV basis)	198790	196897	6017	
Ambient Conditions				
Pressure Altitude (MSL)	3090	3090	3090	
Atmospheric Pressure ("Hg)	26.75	26.75	26.75	
Dry Bulb Temperature (°F)	41.7	42.1	44.8	
Wet Bulb Temperature (°F)	35.8	35.1	38.5	
Humidity (lb/lb air)	0.0035	0.0032	0.0040	
Measured Exhaust Emissions (Corrected)				*Average*
NOx (ppmv)	67.41	71.88	69.61	**69.63**
CO (ppmv)	13.62	8.90	8.16	**10.23**
O2 (vol %)	16.77	16.79	16.79	**16.78**
CO2 (vol %)	2.46	2.54	2.53	**2.51**
Fo (Natural Gas)	1.67	1.62	1.62	**1.64**
Exhaust Flow Rates (EPA Method 19 - Fuel Based)				
Dry SCFH (dry basis, calc. from Fuel Consumption)	910,503	914,424	913,092	**912,673**
Calculated Mass Emission Rates (EPA Method 19)				
NOx (lbs/hr) **{Permit Limit = 27.0}**	7.33	7.85	7.59	**7.59**
CO (lbs/hr) **{Permit Limit = 7.4}**	0.90	0.59	0.54	**0.68**
NOx (tons/yr) **{Permit Limit = 118.3}**	32.11	34.38	33.25	**33.25**
CO (tons/yr) **{Permit Limit = 32.5}**	3.95	2.59	2.37	**2.97**

Summary of Results
South Carlsbad Compressor Station, Unit #2

Company: Enterprise Field Services
Location: South Carlsbad Compressor Station
Source: Solar Centaur 40-T4702 SN: OHE12C7057
Engine Site Rating: 3609 Hp @ 15000 RPM
Technician: JC,FC
Sample System #: 2

Test Run Number	*1*	*2*	*3*	
Emissions Unit	**2**	**2**	**2**	
Date	1/20/16	1/20/16	1/20/16	
Start Time	7:53	8:18	8:43	
Stop Time	8:13	8:38	9:03	
Engine/Compressor Operation				
Turbine Load (%)	**94.7**	**95.2**	**95.3**	
Gas Producer Speed (%)	94.7	95.2	95.3	
Power Turbine Speed (%)	85.2	85.7	86.1	
Engine Horsepower (Hp)	3418	3436	3439	
Engine Compressor Discharge, PCD (psig)	109	110	110.0	
Fuel Valve Output (%)	39.2	39.5	39.6	
Suction Pressure (psig)	237	236	236	
Discharge Pressure (psig)	427	428	427	
Suction Temperature (°F)	41	42	42	
Discharge Temperature (°F)	123	124	125	
Air Inlet Temperature (T1) (°F)	40.2	39	41	
Average Exhaust Temperature (T5) (°F)	1080	1047	1056	
Compressor Throughput (MCFD)	72	72	72	
Fuel Data				
Measured Fuel Consumption (MSCFD)	788	788	788	
Calculated Fuel Consumption (SCFH)	17905	17905	17905	
O2 F-Factor (DSCF/MMBtu, HHV basis)	8696	8696	8696	
Fuel Heating Value (Btu/SCF, HHV)	1155	1155	1155	
BHp Specific Fuel Rate (Btu/Hp-hr, HHV basis)	6049	6017	6011	
Ambient Conditions				
Pressure Altitude (MSL)	3090	3090	3090	
Atmospheric Pressure ("Hg)	26.75	26.75	26.75	
Dry Bulb Temperature (°F)	41.7	42.1	44.8	
Wet Bulb Temperature (°F)	35.8	35.1	38.5	
Humidity (lb/lb air)	0.0035	0.0032	0.0040	
Measured Exhaust Emissions (Corrected)				*Average*
NOx (ppmv)	71.70	75.09	73.53	**73.44**
CO (ppmv)	14.67	12.03	9.98	**12.23**
O2 (vol %)	17.59	17.45	17.30	**17.45**
CO2 (vol %)	2.00	2.12	2.18	**2.10**
Fo (Natural Gas)	1.66	1.63	1.65	**1.65**
Exhaust Flow Rates (EPA Method 19 - Fuel Based)				
Dry SCFH (dry basis, calc. from Fuel Consumption)	1,134,456	1,087,659	1,044,190	**1,088,769**
Calculated Mass Emission Rates (EPA Method 19)				
NOx (lbs/hr) **{Permit Limit = 27.0}**	9.71	9.75	9.17	**9.55**
CO (lbs/hr) **{Permit Limit = 7.4}**	1.21	0.95	0.76	**0.97**
NOx (tons/yr) **{Permit Limit = 118.3}**	42.55	42.72	40.17	**41.81**
CO (tons/yr) **{Permit Limit = 32.5}**	5.30	4.17	3.32	**4.26**

Enterprise Field Services, LLC
South Carlsbad Compressor Station

Solar Centaur T4702 Turbines	Interest Rate:	8.38%		
Unit 1				
	$SoloNO_X$ Period:	20	years	
Base Emissions				
NO_X ppm:		81.7	ppm	<-- Average of 2016-2018 Stack Test Data
NO_X tpy:		69.77	tpy	<-- Average of 2016-2018 EI Data
$SoloNO_X$				
NO_X guarantee:		25	ppm	<-- From Solar
NO_X tpy:		21.36	tpy	
Total Cap Investment	$	1,342,700		<-- Equipment, installation, engineering, and inspection costs
Annualized TCI:	$	140,631		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	37,756		<-- Routine overhaul and labor costs
Total Annual Costs:	$	178,387		
Emissions Reduction:		48.42	tpy	
Cost Effectiveness:	**$**	**3,684.43**	**$/ton**	

Enterprise Field Services, LLC
South Carlsbad Compressor Station

Solar Centaur T4702 Turbines	Interest Rate:	8.38%		
Unit 2				
	$SoloNO_X$ Period:	20	years	
Base Emissions				
NO_X ppm:		89.7	ppm	<-- Average of 2016-2018 Stack Test Data
NO_X tpy:		80.04	tpy	<-- Average of 2016-2018 EI Data
$SoloNO_X$				
NO_X guarantee:		25	ppm	<-- From Solar
NO_X tpy:		22.32	tpy	
Total Cap Investment	$	1,342,700		<-- Equipment, installation, engineering, and inspection costs
Annualized TCI:	$	140,631		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	37,756		<-- Routine overhaul and labor costs
Total Annual Costs:	$	178,387		
Emissions Reduction:		57.72	tpy	
Cost Effectiveness:	**$**	**3,090.40**	**$/ton**	

Enterprise Field Services, LLC
South Carlsbad Compressor Station

Solar Centaur T4702 Turbines	Interest Rate:	8.38%		
Unit 1				
	$SoloNO_X$ Period:	20	years	
Base Emissions				
NO_X ppm:		113.9	ppm	<-- Average of 2016 to 2018 Stack Test Data
NO_X tpy:		69.77	tpy	<-- Average of 2016 to 2018 EI Data
$SoloNO_X$				
NO_X guarantee:		25	ppm	<-- From Solar
NO_X tpy:		15.31	tpy	
Total Cap Investment	$	1,342,700		<-- Equipment, installation, engineering, and inspection costs
Annualized TCI:	$	140,631		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	37,756		<-- Routine overhaul and labor costs
Total Annual Costs:	$	178,387		
Emissions Reduction:		54.46	tpy	
Cost Effectiveness:	**$**	**3,275.38**	**$/ton**	

Enterprise Field Services, LLC
South Carlsbad Compressor Station

Solar Centaur T4702 Turbines
Unit 2

Interest Rate: 8.38%

SoloNO$_X$ Period: 20 years

Base Emissions				
NO$_X$ ppm:		129.7	ppm	<-- Average of 2016 to 2018 Stack Test Data
NO$_X$ tpy:		80.04	tpy	<-- Average of 2016 to 2018 EI Data
SoloNO$_X$				
NO$_X$ guarantee:		25	ppm	<-- From Solar
NO$_X$ tpy:		15.42	tpy	
Total Cap Investment	$	1,342,700		<-- Equipment, installation, engineering, and inspection costs
Annualized TCI:	$	140,631		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	37,756		<-- Routine overhaul and labor costs
Total Annual Costs:	$	178,387		
Emissions Reduction:		64.62	tpy	
Cost Effectiveness:	**$**	**2,760.76**	**$/ton**	

Enterprise Products

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS HOLDINGS LLC
(General Partner)

ENTERPRISE PRODUCTS OPERATING LLC

October 1, 2020

7019 1640 0001 3129 8747
Return Receipt Requested

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505

Re: NMED Follow-Up Discussion Response
Regional Haze Four-Factor Analysis
Enterprise Field Services, LLC
South Carlsbad Compressor Station

Mr. Singleton:

Enterprise Field Services, LLC ("Enterprise") submits herein to the New Mexico Environment Department (NMED) its responses to the follow-up requests from a virtual meeting held on August 28, 2020 for the Regional Haze Four-Factor Analysis submitted for the Enterprise South Carlsbad Compressor Station located in Eddy County, New Mexico. The NMED requested information regarding six additional items identified as (a) through (f) in email correspondence dated September 2, 2020. Enterprise responded to each of the six items and committed to further developing and providing additional information for requests (b) and (c). The NMED follow-up requests and Enterprise responses for requests (b) and (c) are provided below.

Enterprise considers the information included in Attachment A of the enclosed response to be confidential business information (CBI) and requests that it be treated as such to the full extent of applicable law.

NMED Request (b): *We discussed an adjustment to the interest rate Enterprise originally used in its amortization of capital costs. You made an argument to use an interest rate higher than the adjusted rate of 3.25% NMED presented. Please provide in writing the reasoning for your higher interest rate (on top of the explanation provided in an email communication provided to NMED earlier this year), more precisely, the interest rate that would be specific to Enterprise for air pollution control projects. Note that no other New Mexico 4-factor submittal used an interest rate as high as the 8.38% you suggested would be appropriate to Enterprise. Providing official information from a potential lender would support your case when EPA and other entities review NMED's Regional Haze recommendations.*

P.O. BOX 4324
HOUSTON, TEXAS 77210-4324
713.381.6500

1100 LOUISIANA STREET
HOUSTON, TEXAS 77002-5227
www.enterpriseproducts.com

Enterprise Response: In our original Four-Factor Analysis, Enterprise used an annual interest rate of 8.38% based on its application of a 2018 FERC rulemaking that reflected an average capital structure for Enterprise's industry of 57% equity (with an average 10.55% annual return) and 43% debt (to which Enterprise applied the then-applicable prime rate of 5.5%). This approach tracked the basic manner in which Enterprise's industry raises funds, i.e. through a combination of investment equity and taking on debt. The NMED's response stated that Enterprise's proposed rate "is appropriate for pipeline operation and construction, not for air pollution control technologies. The prime rate [3.25%] or a rate specific to Enterprise should be used, and a rate representative of 2020 conditions."

Enterprise respectfully disagrees with the NMED's statement that the FERC methodology is only appropriate for pipeline construction and operation. As noted during our August 28, 2020 virtual meeting, Enterprise's cost of capital is based on the company's overall health and financial condition and generally is not sensitive to the specific purpose for which capital is raised. Put another way, Enterprise would not expect to obtain a lower interest rate on expenses for air pollution control equipment than for other types of expenses such as pipeline construction and operation. Accordingly, we continue to believe that the 8.38% rate derived from the FERC methodology would have been suitable for the Four-Factor Analysis. We also do not believe that the NMED's proposed prime rate of 3.25%, which reflects highly unusual but ultimately temporary conditions in the economy as the result of the COVID-19 pandemic, is a suitable basis for calculating the cost of control measures that would be implemented years in the future when interest rates are likely to return to higher levels more commensurate with their historical patterns.

Nonetheless, at the NMED's request, Enterprise has calculated a company-specific interest rate of 9.62% as of June 30, 2020 and requests that the NMED rely on this interest rate to calculate the cost-effectiveness of potential control measures on our facilities. This interest rate was calculated by Enterprise's Finance department using the Capital Asset Pricing Model. We emphasize that this interest rate reflects our company's overall cost of capital and is applicable to capital raised for a range of purposes, including air pollution control costs, construction of new facilities, or otherwise. The specific calculations behind this interest rate are described in the confidential white paper included as Attachment A. Enterprise consents to disclosure of the 9.62% rate and this explanation in the NMED's public record. However, we request that the NMED treat the white paper itself (i.e. Attachment A) as our confidential business information.

Enterprise has revised the cost-effectiveness calculations for potential retrofit control technologies for the combustion units subject to the Four-Factor Analysis at the South Carlsbad Compressor Station using the calculated company-specific interest rate of 9.62%. The revised cost-effectiveness calculations are enclosed as Attachment B.

NMED Request (c): *Replacing turbines with electric compressors has not been excluded from consideration; therefore, a technical feasibility analysis and cost analysis is required. Given the deadline of September 10 for NMED to submit information to WRAP for the 2nd round PAC photochemical grid modeling, a qualitative ballpark estimate will suffice if you cannot put together*

a comprehensive analysis within the next week. However, a more complete analysis would be appreciated by the end of the month.

Enterprise Response: To assess the potential conversion of combustion driven compressors to electric driven compressors, numerous significant considerations require evaluation. For the purposes of this discussion, Enterprise has evaluated existing electrical capacity to determine the additional electrical capacity that likely would be required to provide equivalent station horsepower for the units that are subject to the Four-Factor Analysis. The total added electric load that would be required if the two Solar Centaur T-4702 turbines (Units 1 and 2) were converted to electric driven units is approximately 5,400 kilowatts (KW). There is only minimal unused existing electrical capacity currently available at the South Carlsbad Compressor Station, and additional electricity demand would require utility infrastructure upgrades by the electricity provider and at the South Carlsbad Compressor Station; these costs would be borne by Enterprise. The electricity provider would have to modify its existing 12 kilovolt (kV) distribution system to provide the additional load. In addition to replacing the two combustion driven compressor packages with electric compressor packages, Enterprise would need to construct additional utility infrastructure within the South Carlsbad Compressor Station to distribute the energy needed to drive the electric compressors. Cost-effectiveness figures for electrification of each unit, including the cost estimation methodology used to estimate the total capital investment, is included in Attachment C. Please note that the electrification costs are based on best professional judgement and not reflective of an actual quoted facility-specific price.

Enterprise does not believe that any further evaluation of electrification of the two units at the South Carlsbad Compressor Station would be warranted. Redefining a source is not a retrofit control technology and is beyond the authority of the Regional Haze Rule.

Should you have any questions regarding this submittal, please contact Tucker Jacobson at (713) 381-4313 (wtjacobson@eprod.com) or Bradley Cooley at (713) 381-5828.

Sincerely,
Enterprise Field Services, LLC

W. Tucker Jacobson
Scientist, Senior Environmental

Bradley J. Cooley, P.E.
Director, Environmental

/bmh
Enclosure

Attachment A (Confidential Business Information)

Company-Specific Interest Rate Calculation

The Confidential information in this Attachment meets the conditions of NMAC § 20.2.1.115.B(3), as follows. Enterprise considers the information to be confidential, and requests that it be treated as such to the full extent of applicable law. We have taken reasonable measures to protect the confidentiality by keeping the information in secure data systems that are only available to authorized users, who are subject to confidentiality obligations per company policy, and by making this confidentiality claim. Further, neither NMED nor a third party could obtain the information without our consent, as this is information developed by Enterprise.

Attachment B

Revised Cost-Effectiveness Calculations with Company-Specific Interest Rate

Enterprise Field Services, LLC

South Carlsbad Compressor Station

Solar Centaur T4702 Turbine Unit 1	Interest Rate:	9.62%	<-- Company-specific interest rate as of 6/30/20
	$SoloNO_X$ Period:	20 years	
Base Emissions			
NO_X ppm:	113.9	ppm	<-- Average of 2016 to 2018 Stack Test Data
NO_X tpy:	69.77	tpy	<-- Average of 2016 to 2018 EI Data
$SoloNO_X$			
NO_X guarantee:	25	ppm	<-- From Solar
NO_X tpy:	15.31	tpy	
Total Cap Investment	$ 2,336,400		<-- Control System Cost from Solar and estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 267,349		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 37,756		<-- Incremental annual inspection and overhaul costs for unit equipped with $SoloNO_X$
Total Annual Costs:	$ 305,105		
Emissions Reduction:	54.46	tpy	
Cost Effectiveness:	**$ 5,602.04**	**$/ton**	

Enterprise Field Services, LLC

South Carlsbad Compressor Station

Solar Centaur T4702 Turbine Unit 2	Interest Rate:	9.62%	<-- Company-specific interest rate as of 6/30/20
	$SoloNO_X$ Period:	20 years	
Base Emissions			
NO_X ppm:	129.7	ppm	<-- Average of 2016 to 2018 Stack Test Data
NO_X tpy:	80.04	tpy	<-- Average of 2016 to 2018 EI Data
$SoloNO_X$			
NO_X guarantee:	25	ppm	<-- From Solar
NO_X tpy:	15.42	tpy	
Total Cap Investment	$ 2,336,400		<-- Control System Cost from Solar and estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 267,349		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 37,756		<-- Incremental annual inspection and overhaul costs for unit equipped with $SoloNO_X$
Total Annual Costs:	$ 305,105		
Emissions Reduction:	64.62	tpy	
Cost Effectiveness:	**$ 4,721.86**	**$/ton**	

TOTAL CAPITAL INVESTEMENT COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
SOUTH CARLSBAD COMPRESSOR STATION

South Carlsbad CS		
Cost Estimation Methodology Used:	**EPA Air Pollution Control Cost Manual Section 5.2, Chapter 1, Table 1.3[1]**	
Unit:	**Unit 1**	**Unit 2**
Control Technology:	**SoloNOx**	**SoloNOx**
Control System Cost (Vendor Estimate):	$ 900,000	$ 900,000
PEC (Control System Cost*1.18):	$ 1,062,000	$ 1,062,000
DIC (PEC*0.85)	$ 902,700	$ 902,700
DC (PEC + DIC):	$ 1,964,700	$ 1,964,700
IC (PEC*0.35) :	$ 371,700	$ 371,700
Total Capital Investment (DC+IC):	**$ 2,336,400**	**$ 2,336,400**

[1] https://www.epa.gov/sites/production/files/2020-07/documents/cs5-2ch1.pdf

PEC - Purchased Equipment Cost	Control equipment
DIC - Direct Installation Cost	Foundation/supports, handling/erection, electrical, piping, installation of ductwork, painting
DC - Direct Cost	PEC and DIC
IC - Indirect Cost	Engineering, Construction and field expenses, contractor fees, start-up, performance test, contingencies

Attachment C

Cost-Effectiveness Calculations for Electrification of Combustion Units

Enterprise Field Services, LLC

South Carlsbad Compressor Station

Solar Centaur T4702 Turbine Unit 1	Interest Rate:	9.62%	<-- Company-specific interest rate as of 6/30/20
	Period:	20 years	
Base Emissions			
NO_X ppm:	113.9	ppm	<-- Average of 2016 to 2018 Stack Test Data
NO_X tpy:	69.77	tpy	<-- Average of 2016 to 2018 EI Data
Electric			
NO_X guarantee:	0	ppm	
NO_X tpy:	0.00	tpy	
Total Cap Investment	$ 10,316,374		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,180,481		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ -		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$ 1,180,481		
Emissions Reduction:	69.77	tpy	
Cost Effectiveness:	**$ 16,918.71**	**$/ton**	

Enterprise Field Services, LLC

South Carlsbad Compressor Station

Solar Centaur T4702 Turbine Unit 2	Interest Rate:	9.62%	<-- Company-specific interest rate as of 6/30/20
	Period:	20 years	
Base Emissions			
NO_X ppm:	129.7	ppm	<-- Average of 2016 to 2018 Stack Test Data
NO_X tpy:	80.04	tpy	<-- Average of 2016 to 2018 EI Data
Electric			
NO_X guarantee:	0	ppm	
NO_X tpy:	0.00	tpy	
Total Cap Investment	$ 10,316,374		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,180,481		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ -		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$ 1,180,481		
Emissions Reduction:	80.04	tpy	
Cost Effectiveness:	**$ 14,748.76**	**$/ton**	

TOTAL CAPITAL INVESTEMENT COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
SOUTH CARLSBAD COMPRESSOR STATION

South Carlsbad CS		
Cost Estimation Methodology Used:	**EPA Air Pollution Control Cost Manual Section 5.2, Chapter 1, Table 1.3**[1]	
Unit:	**Unit 1**	**Unit 2**
Combustion Unit:	**Solar Centaur T-4702**	**Solar Centaur T-4702**
Electric Infrastructure Cost:	$ 2,435,000	$ 2,435,000
Electric Motor/Compressor Cost:	$ 1,538,950	$ 1,538,950
PEC (Electrification Cost*1.18):	$ 4,689,261	$ 4,689,261
DIC (PEC*0.85)	$ 3,985,872	$ 3,985,872
DC (PEC + DIC):	$ 8,675,132	$ 8,675,132
IC (PEC*0.35) :	$ 1,641,241	$ 1,641,241
Total Capital Investment (DC+IC):	**$ 10,316,374**	**$ 10,316,374**

[1] https://www.epa.gov/sites/production/files/2020-07/documents/cs5-2ch1.pdf

PEC - Purchased Equipment Cost	Control equipment
DIC - Direct Installation Cost	Foundation/supports, handling/erection, electrical, piping, installation of ductwork, painting
DC - Direct Cost	PEC and DIC
IC - Indirect Cost	Engineering, Construction and field expenses, contractor fees, start-up, performance test, contingencies

From: Jacobson, Tucker <WTJACOBSON@eprod.com>
Sent: Tuesday, September 8, 2020 4:01 PM
To: Zyla, Rhett, NMENV
Cc: Jones, Mark, NMENV; Baca, Michael, NMENV; Butt, Neal, NMENV; Singleton,Kerwin, NMENV; Cooley, Bradley; Craft, Zachary; Kulkarni, Pranav; Adam Erenstein; Fichthorn, Norm
Subject: [EXT] RE: Enterprise Regional Haze 4FA Follow-up Discussion
Attachments: South Carlsbad CS - Revised Cost Effectiveness Tables with Backup.pdf; Blanco C & D CS - Revised Cost Effectiveness Tables with Backup.pdf; Chaco Gas Plant - Revised Cost Effectiveness Tables with Backup.pdf

Rhett,

Good afternoon. Please see responses to each of the items listed below in RED. We will provide more information to Items b and c once available.

Thanks
Tucker

Tucker Jacobson
Senior Environmental Scientist
Enterprise Products
1100 Louisiana St.
Houston, Texas 77002-5227
713-381-4313 (office)
832-444-3650 (cell)
wtjacobson@eprod.com

From: Zyla, Rhett, NMENV <Rhett.Zyla@state.nm.us>
Sent: Wednesday, September 2, 2020 10:36 AM
To: Jacobson, Tucker <WTJACOBSON@eprod.com>; Cooley, Bradley <bjcooley@eprod.com>; Kulkarni, Pranav <pkulkarni@eprod.com>; Craft, Zachary <zlcraft@eprod.com>; Adam Erenstein <AErenstein@trinityconsultants.com>; Fichthorn, Norm <nfichthorn@hunton.com>
Cc: Jones, Mark, NMENV <Mark.Jones@state.nm.us>; Baca, Michael, NMENV <michael.baca1@state.nm.us>; Butt, Neal, NMENV <Neal.Butt@state.nm.us>; Singleton,Kerwin, NMENV <Kerwin.Singleton@state.nm.us>
Subject: [EXTERNAL] Enterprise Regional Haze 4FA Follow-up Discussion

[Use caution with links/attachments]
Hello all,

Thank you for meeting with us to discuss your 4-Factor Analyses and our follow-up questions and requests. The information provided to us in the meeting is helpful and productive as we develop our Regional Haze SIP.

Below is a reiteration and post-discussion clarification of the items we discussed and information needed.

Enterprise: South Carlsbad CS, Blanco C&D CS, Chaco GP

a. Please provide a more detailed, itemized cost breakdown for capital and O&M costs. The example originally attached to the invite was a guideline only, but illustrates the detail NMED needs (as will EPA and other stakeholders) to vet and confirm appropriate categories of consideration. Please see the attached cost analyses for each facility that includes backup on how Total Capital Investment and O&M costs were estimated. Based on the guidance provided by NMED and discussion on 8/28/20, we revised our Total Capital Investment value for each unit and NOx reduction technology consistent with the methodology used in EPA Air Pollution Control Manual, Section 5.2, Chapter 1, Table 1.3. For water and steam injection technology, O&M costs were also updated since those values were estimated based on a percentage of the Total Capital Investment value.

b. We discussed an adjustment to the interest rate Enterprise originally used in its amortization of capital costs. You made an argument to use an interest rate higher than the adjusted rate of 3.25% NMED presented. Please provide in writing the reasoning for your higher interest rate (on top of the explanation provided in an email communication provided to NMED earlier this year), more precisely, the interest rate that would be specific to Enterprise for air pollution control projects. Note that no other New Mexico 4-factor submittal used an interest rate as high as the 8.38% you suggested would be appropriate to Enterprise. Providing official information from a potential lender would support your case when EPA and other entities review NMED's Regional Haze recommendations. Enterprise is preparing a response and will provide to NMED once available. As mentioned in email correspondence dated 3/26/20 and discussion on 8/28/20, Enterprise does not believe that a prime rate of 3.25% is appropriate and that actual interest rates would be significantly higher. It should be noted that EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1 suggests an interest rate of 7%.

c. Replacing turbines with electric compressors has not been excluded from consideration; therefore, a technical feasibility analysis and cost analysis is required. Given the deadline of September 10 for NMED to submit information to WRAP for the 2nd round PAC photochemical grid modeling, a qualitative ballpark estimate will suffice if you cannot put together a comprehensive analysis within the next week. However, a more complete analysis would be appreciated by the end of the month Enterprise is preparing an analysis that will be available by the end of the month. The analysis will generally include a comparison of the amount of available existing electrical capacity at each facility compared with the additional power capacity needed to maintain existing operational capacity at each facility. Based on preliminary review of available information, we expect that conversion of combustion engines to electric drivers will not be cost effective compared to other pollution control options.

d. The Blanco C&D CS T-D01 dry low NOx system capital cost reported in your 4-factor submittal is $8,205,400; whereas, the information provided in your follow-up CBI on page 4 of 4 is notably less. Please clarify. This is another example of where a more detailed breakdown/itemization of costs is required, per the itemization guidelines originally attached in the email invite. The cost provided in the follow-up CBI documentation (vendor cost) did not include all direct and indirect costs, please see the attached back-up that summarizes how the Total Capital Investment cost was estimated.

e. What is the control efficiency for the Chaco Gas Plant LEC controls on the Clark TLA-10 engines? As discussed on 8/28/20, the control efficiency is 50%.

f. What are the Chaco Gas Plant actual sulfur dioxide and H2S emissions from the sweetening process venting and flaring and how are they minimized Sweetening at the Chaco Gas Plant occurs on the NGL product stream, after the cryogenic process, for CO2 removal to meet pipeline specifications. Although the purpose of the sweetening unit at Chaco is generally to remove CO2, small quantities of H2S are also removed. CO2 and H2S are routed to a Callidus Thermal Oxidizer (Unit ID: 46) for destruction. Below are emissions for the TO (Unit ID: 46) as reported in annual emission inventories from CY 2015-2019:

Year	Volume Combusted (MMSCF)	tons/yr	
		H2S	SO2
2019	1,840.25	1.8	3.3
2018	1,798.33	1.7	1.7
2017	1,775.04	1.7	1.5
2016	1,832.21	1.8	1.6
2015	1,773.29	0.0	3.3

Stakeholder comments on Regional Haze can be found at: https://www.env.nm.gov/air-quality/rh-stakeholder-comments-2021/.
4-factor submittals can be found at: https://www.env.nm.gov/air-quality/four_factor_analysis-reports/

ETC Jal#3 is at least one facility that submitted information on electrification as a control measure option. Keep in mind that Jal's cost analysis was not correctly done.

We would appreciate any information that you can provide to us by September 8 so we may consider it before we submit information for the PAC #2 modeling run. The remainder of the information can be submitted by September 30, 2020 to the extent possible. We will be available to receive this information and answer any questions or address any comments you may have.

Please let me know if I missed anything or if you have any questions about this.

Thank you,

Rhett Zyla, EIT
Environmental Scientist and Engineer – Planning Section

New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez
Santa Fe, NM 87505
505.476.4304 (O)
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https://www.env.nm.gov/air-quality

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Enterprise Field Services, LLC

Blanco C&D Compressor Station

GE 5221W Turbines	Interest Rate:	8.38%	
Unit T-CO1			
	Water/Steam Injection Period:	15 years	

Base Emissions

NO_X ppm:	51.2	ppm	<-- Average of 2016-2018 Stack Test Data
NO_X tpy:	139.23	tpy	<-- Average of 2016-2018 EI Data

Water Injection

NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:	114.13	tpy	
Total Capital Investment:	$ 10,643,600		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,272,373		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,965,077		<-- Inspection and operating costs
Total Annual Costs:	$ 3,237,450		
Emissions Reduction:	25.09	tpy	
Cost Effectiveness:	**$ 129,025.88**	**$/ton**	

Steam Injection

NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:	114.13	tpy	
Total Cap Investment	$ 14,018,400		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,675,808		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 2,848,666		<-- Inspection and operating costs
Total Annual Costs:	$ 4,524,474		
**Emissions Reduction:	25.09	tpy	
Cost Effectiveness:	**$ 180,319.16**	**$/ton**	

** Additional NO_X emissions from the boiler are not considered in this emission reduction.

Enterprise Field Services, LLC

Blanco C&D Compressor Station

GE 5221W Turbines	Interest Rate:	8.38%		
Unit T-CO2				
	Water/Steam Injection Period:	15	years	
Base Emissions				
NO_X ppm:		69.1	ppm	<-- Average of 2016-2018 Stack Test Data
NO_X tpy:		157.53	tpy	<-- Average of 2016-2018 EI Data
Water Injection				
NO_X guarantee:		42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:		95.71	tpy	
Total Capital Investment:	$	10,643,600		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	1,272,373		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	1,965,077		<-- Inspection and operating costs
Total Annual Costs:	$	3,237,450		
Emissions Reduction:		61.83	tpy	
Cost Effectiveness:	**$**	**52,361.63**	**$/ton**	
Steam Injection				
NO_X guarantee:		42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:		95.71	tpy	
Total Cap Investment	$	14,018,400		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	1,675,808		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	2,848,666		<-- Inspection and operating costs
Total Annual Costs:	$	4,524,474		
**Emissions Reduction:		61.83	tpy	
Cost Effectiveness:	**$**	**73,177.60**	**$/ton**	

** Additional NO_X emissions from the boiler are not considered in this emission reduction.

Enterprise Field Services, LLC

Blanco C&D Compressor Station

GE M5322B Turbine
Unit T-DO1

Interest Rate: 8.38%

DLN Period: 20 years
Water/Steam Injection Period: 15 years

Base Emissions

NO_X ppm:	59.0	ppm	<-- From 2016-2018 Stack Test Data
NO_X tpy:	215.21	tpy	<-- Average of 2016-2018 EI Data

Dry Low NO_X

NO_X guarantee:	35	ppm	<-- From Baker Hughes
NO_X tpy:	127.69	tpy	
Total Cap Investment	$ 14,278,000		<-- Control System Cost from Baker Hughes; estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,495,445		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 44,986		<-- Incremental overhaul costs
Total Annual Costs:	$ 1,540,431		
Emissions Reduction:	87.52	tpy	
Cost Effectiveness:	**$ 17,601.19**	**$/ton**	

Water Injection

NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:	153.23	tpy	
Total Cap Investment:	$ 10,643,600		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,272,373		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,965,077		<-- Inspection and operating costs
Total Annual Costs:	$ 3,237,450		
Emissions Reduction:	61.98	tpy	
Cost Effectiveness:	**$ 52,233.35**	**$/ton**	

Steam Injection

NO_X guarantee:	42	ppm	<-- ACT Document,Assessment of Non-EGU Emission Controls
NO_X tpy:	153.23	tpy	
Total Cap Investment	$ 14,018,400		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,675,808		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 2,848,666		<-- Inspection and operating costs
Total Annual Costs:	$ 4,524,474		
Emissions Reduction:	61.98	tpy	
Cost Effectiveness:	**$ 72,998.33**	**$/ton**	

** Additional NO_X emissions from the boiler are not considered in this emission reduction.

TOTAL CAPITAL INVESTEMENT COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
BLANCO C & D COMPRESSOR STATION

Blanco C & D Compressor Station							
Cost Estimation Methodology Used:	EPA Air Pollution Control Cost Manual Section 5.2, Chapter 1, Table 1.3 [1]						
Unit:	T-C01		T-C02		T-D01		
Control Technology:	**Water Injection**	**Steam Injection**	**Water Injection**	**Steam Injection**	**Dry Low NO_X (DLN)**	**Water Injection**	**Steam Injection**
Control System Cost (Estimate):	$ 4,100,000	$ 5,400,000	$ 4,100,000	$ 5,400,000	$ 5,500,000	$ 4,100,000	$ 5,400,000
PEC (Control System Cost*1.18):	$ 4,838,000	$ 6,372,000	$ 4,838,000	$ 6,372,000	$ 6,490,000	$ 4,838,000	$ 6,372,000
DIC (PEC*0.85)	$ 4,112,300	$ 5,416,200	$ 4,112,300	$ 5,416,200	$ 5,516,500	$ 4,112,300	$ 5,416,200
DC (PEC + DIC):	$ 8,950,300	$ 11,788,200	$ 8,950,300	$ 11,788,200	$ 12,006,500	$ 8,950,300	$ 11,788,200
IC (PEC*0.35) :	$ 1,693,300	$ 2,230,200	$ 1,693,300	$ 2,230,200	$ 2,271,500	$ 1,693,300	$ 2,230,200
Total Capital Investment (DC+IC):	**$ 10,643,600**	**$ 14,018,400**	**$ 10,643,600**	**$ 14,018,400**	**$ 14,278,000**	**$ 10,643,600**	**$ 14,018,400**

[1] https://www.epa.gov/sites/production/files/2020-07/documents/cs5-2ch1.pdf

PEC - Purchased Equipment Cost	Control equipment
DIC - Direct Installation Cost	Foundation/supports, handling/erection, electrical, piping, installation of ductwork, painting
DC - Direct Cost	PEC and DIC
IC - Indirect Cost	Engineering, Construction and field expenses, contractor fees, start-up, performance test, contingencies

DETAILED O&M COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
BLANCO C & D COMPRESSOR STATION

Facility	Combustion Source	Unit No.	NOx Reduction Technology	*Additional Annual O&M Cost*		
				Annual Inspection and Overhaul Costs[1]	Ancillary Equipment O&M Cost (Water Supply/Boiler)[2]	Annual Total
Blanco C&D Compressor Station	GE Frame 5	T-C01	Water Injection	$49,229	$1,915,848	$1,965,077
			Steam Injection	$44,986	$2,803,680	$2,848,666
	GE Frame 5	T-C02	Water Injection	$49,229	$1,915,848	$1,965,077
			Steam Injection	$44,986	$2,803,680	$2,848,666
	GE M5322B	T-D01	Dry Low NO_X (DLN)	$44,986	-	$44,986
			Water Injection	$49,229	$1,915,848	$1,965,077
			Steam Injection	$44,986	$2,803,680	$2,848,666

Notes:

[1] Based on incremental costs for new emission control equipment as provided by vendor.

[2] Ancillary Equipment O&M cost is based on the following:

Water Injection: Annual O&M Costs = 18% of Capital Cost

Steam Injection: Annual O&M Costs = 20% of Capital Cost

Enterprise Field Services, LLC

Chaco Gas Plant

GE Frame 5 Turbines	Interest Rate:	8.38%	
Unit 17			
	Water/Steam Injection Period:	15 years	

Base Emissions

NO_X ppm:		54.7 ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:		29.15 lb/hr	<-- From 2016 Stack Test Data
NO_X tpy:		126.82 tpy	<-- Calculated

Water Injection

NO_X guarantee:		46 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:		24.78 lb/hr	
NO_X tpy:		107.80 tpy	
Total Cap Investment	$	10,643,600	<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	1,272,373	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	1,965,077	<-- Inspection and operating costs
Total Annual Costs:	$	3,237,450	
Emissions Reduction:		19.02 tpy	
Cost Effectiveness:	**$**	**170,180.24**	**$/ton**

Steam Injection

NO_X guarantee:		46 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:		24.78 lb/hr	
NO_X tpy:		107.80 tpy	
Total Cap Investment	$	14,018,400	<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	1,675,808	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	2,848,666	<-- Inspection and operating costs
Total Annual Costs:	$	4,524,474	
Emissions Reduction:		19.02 tpy	
Cost Effectiveness:	**$**	**237,834.13**	**$/ton**

Enterprise Field Services, LLC

Chaco Gas Plant

GE Frame 5 Turbines	Interest Rate:	8.38%	
Unit 18			
	Water/Steam Injection Period:	15 years	

Base Emissions

NO_X ppm:		48.7 ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:		29.15 lb/hr	<-- From 2016 Stack Test Data
NO_X tpy:		126.61 tpy	<-- Calculated

Water Injection

NO_X guarantee:		41 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:		24.78 lb/hr	
NO_X tpy:		107.62 tpy	
Total Cap Investment	$	10,643,600	<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	1,272,373	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	1,965,077	<-- Inspection and operating costs
Total Annual Costs:	$	3,237,450	
Emissions Reduction:		18.99 tpy	
Cost Effectiveness:	**$**	**170,464.30**	**$/ton**

Steam Injection

NO_X guarantee:		41 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X lb/hr:		24.78 lb/hr	
NO_X tpy:		107.62 tpy	
Total Cap Investment	$	14,018,400	<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	1,675,808	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	2,848,666	<-- Inspection and operating costs
Total Annual Costs:	$	4,524,474	
Emissions Reduction:		18.99 tpy	
Cost Effectiveness:	**$**	**238,231.11**	**$/ton**

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbines	Interest Rate:	8.38%	
Unit 35			
	$SoloNO_X$ Period:	20 years	

Base Emissions

NO_X ppm:	125	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:	27.72	lb/hr	<-- From 2016 Stack Test Data
NO_X tpy:	119.52	tpy	<-- Calculated

$SoLoNO_X$

NO_X guarantee:	15	ppm	<-- From Solar
NO_X lb/hr:	3.33	lb/hr	
NO_X tpy:	14.34	tpy	
Total Cap Investment	$ 9,086,000		<-- Control System Cost from Solar and estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 951,647		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 124,567		<-- Incremental annual inspection and overhaul costs for unit equipped with $SoloNO_X$
Total Annual Costs:	$ 1,076,214		
Emissions Reduction:	105.18	tpy	
Cost Effectiveness:	**$ 10,232.45**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbines Unit 36	Interest Rate:	8.38%	
	$SoloNO_X$ Period:	20 years	

Base Emissions

NO_X ppm:	122	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:	28.00	lb/hr	<-- Calculated based on NOx concentration
NO_X tpy:	117.84	tpy	<-- Calculated

$SoLoNO_X$

NO_X guarantee:	15	ppm	<-- from Solar
NO_X lb/hr:	3.45	lb/hr	
NO_X tpy:	14.52	tpy	
Total Cap Investment	$ 9,086,000		<-- Control System Cost from Solar and estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 951,647		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 124,567		<-- Incremental annual inspection and overhaul costs for unit equipped with $SoloNO_X$
Total Annual Costs:	$ 1,076,214		
Emissions Reduction:	103.32	tpy	
Cost Effectiveness:	**$ 10,415.91**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbines	Interest Rate:	8.38%	
Unit 37			
	$SoloNO_X$ Period:	20 years	

Base Emissions

NO_X ppm:	103	ppm	<-- From 2016 Stack Test Data
NO_X lb/hr:	22.93	lb/hr	<-- Calculated based on NOx concentration
NO_X tpy:	85.97	tpy	<-- Calculated

$SoLoNO_X$

NO_X guarantee:	15	ppm	<-- from Solar
NO_X lb/hr:	3.33	lb/hr	
NO_X tpy:	12.48	tpy	
Total Cap Investment	$ 9,086,000		<-- Control System Cost from Solar and estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 951,647		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 124,567		<-- Incremental annual inspection and overhaul costs for unit equipped with $SoloNO_X$
Total Annual Costs:	$ 1,076,214		
Emissions Reduction:	73.49	tpy	
Cost Effectiveness:	**$ 14,644.22**	**$/ton**	

TOTAL CAPITAL INVESTEMENT COST SUMMARY OF NO_x REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
CHACO GAS PLANT

Chaco Gas Plant							
Cost Estimation Methodology Used:	EPA Air Pollution Control Cost Manual Section 5.2, Chapter 1, Table 1.3[1]						
Unit:	**17**		**18**		**35**	**36**	**37**
Control Technology:	**Water Injection**	**Steam Injection**	**Water Injection**	**Steam Injection**	**SoloNO_x**	**SoloNO_x**	**SoloNO_x**
Control System Cost (Estimate):	$ 4,100,000	$ 5,400,000	$ 4,100,000	$ 5,400,000	$ 3,500,000	$ 3,500,000	$ 3,500,000
PEC (Control System Cost*1.18):	$ 4,838,000	$ 6,372,000	$ 4,838,000	$ 6,372,000	$ 4,130,000	$ 4,130,000	$ 4,130,000
DIC (PEC*0.85)	$ 4,112,300	$ 5,416,200	$ 4,112,300	$ 5,416,200	$ 3,510,500	$ 3,510,500	$ 3,510,500
DC (PEC + DIC):	$ 8,950,300	$ 11,788,200	$ 8,950,300	$ 11,788,200	$ 7,640,500	$ 7,640,500	$ 7,640,500
IC (PEC*0.35) :	$ 1,693,300	$ 2,230,200	$ 1,693,300	$ 2,230,200	$ 1,445,500	$ 1,445,500	$ 1,445,500
Total Capital Investment (DC+IC):	**$ 10,643,600**	**$ 14,018,400**	**$ 10,643,600**	**$ 14,018,400**	**$ 9,086,000**	**$ 9,086,000**	**$ 9,086,000**

[1] https://www.epa.gov/sites/production/files/2020-07/documents/cs5-2ch1.pdf

PEC - Purchased Equipment Cost	Control equipment
DIC - Direct Installation Cost	Foundation/supports, handling/erection, electrical, piping, installation of ductwork, painting
DC - Direct Cost	PEC and DIC
IC - Indirect Cost	Engineering, Construction and field expenses, contractor fees, start-up, performance test, contingencies

DETAILED O&M COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
CHACO GAS PLANT

				Additional Annual O&M Cost				
Facility	**Combustion Source**	**Unit No.**	**NOx Reduction Technology**	**Hours Between Overhauls[1]**	**Additional Inspection and Overhaul Costs for SoloNOx Units ($/hr)[1]**	**Annual Inspection and Overhaul Costs[1]**	**Ancillary Equipment O&M Cost (Water Supply/Boiler)[2]**	**Annual Total**
Chaco Gas Plant	GE Frame 5	17	Water Injection	-	-	$49,229	$1,915,848	$1,965,077
			Steam Injection	-	-	$44,986	$2,803,680	$2,848,666
	GE Frame 5	18	Water Injection	-	-	$49,229	$1,915,848	$1,965,077
			Steam Injection	-	-	$44,986	$2,803,680	$2,848,666
	Solar Mars T-15000	35	$SoloNO_X$	30,000	$14.22	-	-	$124,567
	Solar Mars T-15000	36	$SoloNO_X$	30,000	$14.22	-	-	$124,567
	Solar Mars T-15000	37	$SoloNO_X$	30,000	$14.22	-	-	$124,567

Notes:

[1] Based on incremental costs for new emission control equipment as provided by vendors.

[2] Ancillary Equipment O&M cost is based on the following:

Water Injection: Annual O&M Costs = 18% of Capital Cost

Steam Injection: Annual O&M Costs = 20% of Capital Cost

Enterprise Field Services, LLC

South Carlsbad Compressor Station

Solar Centaur T4702 Turbines	Interest Rate:	8.38%		
Unit 1				
	$SoloNO_X$ Period:	20	years	
Base Emissions				
NO_X ppm:		113.9	ppm	<-- Average of 2016 to 2018 Stack Test Data
NO_X tpy:		69.77	tpy	<-- Average of 2016 to 2018 EI Data
$SoloNO_X$				
NO_X guarantee:		25	ppm	<-- From Solar
NO_X tpy:		15.31	tpy	
Total Cap Investment	$	2,336,400		<-- Control System Cost from Solar and estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	244,709		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	37,756		<-- Incremental annual inspection and overhaul costs for unit equipped with $SoloNO_X$
Total Annual Costs:	$	282,465		
Emissions Reduction:		54.46	tpy	
Cost Effectiveness:	**$**	**5,186.35**	**$/ton**	

Enterprise Field Services, LLC
South Carlsbad Compressor Station

Solar Centaur T4702 Turbines Unit 2	Interest Rate:	8.38%		
	$SoloNO_X$ Period:	20	years	
Base Emissions				
NO_X ppm:		129.7	ppm	<-- Average of 2016 to 2018 Stack Test Data
NO_X tpy:		80.04	tpy	<-- Average of 2016 to 2018 EI Data
$SoloNO_X$				
NO_X guarantee:		25	ppm	<-- From Solar
NO_X tpy:		15.42	tpy	
Total Cap Investment	$	2,336,400		<-- Control System Cost from Solar and estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	244,709		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	37,756		<-- Incremental annual inspection and overhaul costs for unit equipped with $SoloNO_X$
Total Annual Costs:	$	282,465		
Emissions Reduction:		64.62	tpy	
Cost Effectiveness:	**$**	**4,371.48**	**$/ton**	

TOTAL CAPITAL INVESTEMENT COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
SOUTH CARLSBAD COMPRESSOR STATION

South Carlsbad CS		
Cost Estimation Methodology Used:	**EPA Air Pollution Control Cost Manual Section 5.2, Chapter 1, Table 1.3** [1]	
Unit:	**Unit 1**	**Unit 2**
Control Technology:	**SoloNOx**	**SoloNOx**
Control System Cost (Vendor Estimate):	$ 900,000	$ 900,000
PEC (Control System Cost*1.18):	$ 1,062,000	$ 1,062,000
DIC (PEC*0.85)	$ 902,700	$ 902,700
DC (PEC + DIC):	$ 1,964,700	$ 1,964,700
IC (PEC*0.35) :	$ 371,700	$ 371,700
Total Capital Investment (DC+IC):	**$ 2,336,400**	**$ 2,336,400**

[1] https://www.epa.gov/sites/production/files/2020-07/documents/cs5-2ch1.pdf

PEC - Purchased Equipment Cost	Control equipment
DIC - Direct Installation Cost	Foundation/supports, handling/erection, electrical, piping, installation of ductwork, painting
DC - Direct Cost	PEC and DIC
IC - Indirect Cost	Engineering, Construction and field expenses, contractor fees, start-up, performance test, contingencies

DETAILED O&M COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
SOUTH CARLSBAD COMPRESSOR STATION

Facility	Combustion Source	Unit No.	NOx Reduction Technology	*Additional Annual O&M Cost*		
				Hours Between Overhauls	Additional Inspection and Overhaul Costs for SoloNOx Units ($/hr)	Annual Total[1]
South Carlsbad Compressor Station	Solar Centaur T-4702	1	$SoloNO_X$	30,000	$4.31	$37,756
	Solar Centaur T-4702	2	$SoloNO_X$	30,000	$4.31	$37,756

Notes:

[1] Based on incremental costs for new emission control equipment as provided by vendors.

Enterprise Products

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS HOLDINGS LLC
(General Partner)

ENTERPRISE PRODUCTS OPERATING LLC

March 4, 2021

New Mexico Environment Department – Air Quality Bureau
Attn: Mark Jones, Environmental Analyst
Via email: Mark.Jones@state.nm.us

Re: NMED Regional Haze Four-Factor Analysis
Chaco Gas Plant; Blanco C&D and South Carlsbad Compressor Stations
Company-specific interest rate for Enterprise Field Services, LLC

Dear Mr. Jones:

On October 1, 2020, representatives of Enterprise Field Services, LLC submitted written statements to Kerwin Singleton of your office regarding the NMED's regional haze four-factor analysis for Enterprise's Chaco Gas Plant, Blanco C&D Compressor Station, and South Carlsbad Compressor Station. Each of these three submittals proposed use of a 9.62% company-specific interest rate (based on conditions as of June 30, 2020) for cost analysis of potential air emission controls. The supporting calculations were included in a confidential Attachment A to each submittal, which was titled "Enterprise Products Partners L.P. Capitalization and Cost of Capital Illustration."

By email to Enterprise's Tucker Jacobson on February 18, 2021, you requested additional documentation of this company-specific interest rate and indicated that acceptable documentation would be "in the form of a letter…from an official with your company (your company's CFO, for instance) that is in a position to know your company's costs of debt and equity."

In response to your request, I can confirm that this interest rate was calculated, and the associated document prepared, under my direction. I am familiar with the costs of debt and equity for Enterprise Products entities, including Enterprise Field Services, LLC and Enterprise Products Partners L.P. The attached document and resulting calculation accurately reflected both companies' cost of debt and equity as of June 30, 2020. Enterprise continues to regard the document as confidential.

Kind Regards,

Christian Nelly
Executive Vice President-Finance and Sustainability and Treasurer
Enterprise Field Services, LLC and Enterprise Products Holdings LLC, General Partner of Enterprise Products Partners L.P.
Attachment (Confidential)

P.O. Box 4324
Houston, Texas 77210-4324
713.381.6500

1100 Louisiana Street
Houston, Texas 77002-5227
www.enterpriseproducts.com

Attachment A (Confidential Business Information)

Company-Specific Interest Rate Calculation

The Confidential information in this Attachment meets the conditions of NMAC § 20.2.1.115.B(3), as follows. Enterprise considers the information to be confidential, and requests that it be treated as such to the full extent of applicable law. We have taken reasonable measures to protect the confidentiality by keeping the information in secure data systems that are only available to authorized users, who are subject to confidentiality obligations per company policy, and by making this confidentiality claim. Further, neither NMED nor a third party could obtain the information without our consent, as this is information developed by Enterprise.

Enterprise Products

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS HOLDINGS LLC
(General Partner)

ENTERPRISE PRODUCTS OPERATING LLC

August 30, 2023

via email: michael.baca1@env.nm.gov
mark.jones@env.nm.gov

Kirby Olson
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
P.O. Box 5469
Santa Fe, New Mexico 87502-5469

Re: Updated Cost-Effectiveness Estimates
Regional Haze Four-Factor Analysis
Enterprise Field Services, LLC

Dear Ms. Olson:

Enterprise Field Services, LLC (Enterprise) submits herein to the New Mexico Environment Department (NMED) updates for the Regional Haze Four-Factor Analysis submitted for the following Enterprise facilities:

- South Carlsbad Compressor Station located in Eddy County, New Mexico (South Carlsbad)
- Blanco C & D Compressor Station located in San Juan County, New Mexico (Blanco)
- Chaco Gas Plant located in San Juan County, New Mexico (Chaco)

Pursuant to a virtual meeting held with NMED on July 13, 2023, Enterprise is electing to provide revised cost-effectiveness estimates for previously evaluated retrofit control technologies for combustion units applicable to the Regional Haze Four-Factor Analysis at the three (3) facilities listed above based on 2023 conditions. Prior to this update, the last cost-effectiveness estimates were submitted to NMED on October 1, 2020. With this submittal, Enterprise is updating the cost-effectiveness estimates based on 2022 emissions data and 2023 cost-related factors including the Enterprise company-specific interest rate, cost of retrofit control technology equipment as provided by vendors, and incremental cost of equipment inspection and maintenance attributed to the installation of retrofit control technology. Additionally, at the request of NMED, additional facility-specific information regarding their utility electric supply is contained herein.

Enterprise considers the information included in **Attachment A** and **Attachment B** of this submittal to be **confidential business information (CBI)** and requests that it be treated as such to the full extent of applicable law.

This submittal includes the following attachments:

- Attachment A (**CBI**): Updated Company-Specific Interest Rate Calculation
- Attachment B (**CBI**): Updated Vendor-Provided Retrofit Cost Information

- Attachment C: Updated Cost-Effectiveness Estimates for South Carlsbad
- Attachment D: Updated Cost-Effectiveness Estimates for Blanco
- Attachment E: Updated Cost-Effectiveness Estimates for Chaco

Electrification Discussion

As requested by NMED in the virtual meeting held on July 13, 2023, responses to three questions related to the electrification of combustion units at each facility are provided below:

	Enterprise Response		
NMED Question	**South Carlsbad**	**Blanco**	**Chaco**
Is the facility currently served by utility power?	Yes	Yes	Yes
If yes, could one or more units be electrified without making upgrades to substations or off-site upgrades?	No	No	No
How many miles are we from a substation?	1.5 miles	2.5 miles	25 miles

Enterprise assessed the potential conversion of combustion-driven compressors to electric-driven compressors in correspondence dated October 1, 2020, for South Carlsbad, Blanco, and Chaco, respectively. The 2020 assessment still generally remains valid. Cost-effectiveness estimates for electrification of combustion units applicable to the Regional Haze Four-Factor Analysis have been updated and are included in Attachments C, D, and E for each facility, respectively. For the purposes of this discussion, Enterprise has evaluated existing on-site utility electrical capacity and infrastructure at each facility, respectively, to determine the additional electrical capacity and infrastructure that likely would be required to provide equivalent station horsepower for the units that are subject to the Four-Factor Analysis. Please note that the electrification costs are based on best professional judgment and are not reflective of an actual quoted facility-specific price. Estimated third-party (e.g. electric generating facility) costs that would be borne to serve additional electricity demand if combustion units were electrified are not included.

<u>South Carlsbad</u>
Enterprise confirmed with Xcel Energy, the electric provider for South Carlsbad, that there is not enough existing electrical capacity currently available to the facility, and additional electricity demand would require utility infrastructure upgrades.

<u>Blanco and Chaco</u>
Enterprise confirmed with Farmington Electric Utility System, the electric provider for Blanco and Chaco, that in addition to transmission upgrades that would be required for the electrification of these units, there is no existing spare generation capacity at existing power generating plants; therefore, approximately three (3)-150 megawatt combined cycle power plants would need to be constructed to serve the load required to drive electric motors for the compressors included in this analysis at Blanco and Chaco. The timeline to implement electrification at Blanco and Chaco would be five to eight years, depending on the new third-party generation plant siting requirements, environmental permitting, and right-of-way negotiations. No consideration has been given to potential nitrogen

oxide (NO_X) emissions as a result of generating additional electrical capacity necessary for the electrification of the combustion units at Blanco and Chaco. Electrification is not technically feasible because of the necessary additional power generation and utility infrastructure upgrades needed by the local utility over which Enterprise has no control.

Enterprise does not believe that any further evaluation of electrification of the units at the South Carlsbad, Blanco, and Chaco is warranted.

New Mexico Ozone Precursor Rule Discussion

On August 14, 2023, Enterprise submitted an Alternative Compliance Plan (ACP) in accordance with 20.2.50.113 NMAC (Ozone Precursor Rule) which included all the emission units being evaluated under the Regional Haze Rule along with other units in the Enterprise fleet throughout New Mexico. The ACP addresses NOx, carbon monoxide, and volatile organic compounds emissions and demonstrates how Enterprise will comply with allowable emission standards of NMED's Ozone Precursor Rule. NMED should consider Enterprise's emission reduction strategy proposed in the ACP, as well as other company strategies to comply with the Ozone Precursor Rule, when considering any subsequent control under the Regional Haze Rule.

Enterprise does not believe that implementing any of the evaluated controls for the Regional Haze Rule would meaningfully improve visibility in nearby Class I areas based on previously provided climatological data and ambient pollutant data. Should you have any questions regarding this submittal, please contact Tucker Jacobson at (713) 381-4313 (wtjacobson@eprod.com) or Bradley Cooley at (713) 381-5828 (bjcooley@eprod.com).

Sincerely,
Enterprise Field Services, LLC

W. Tucker Jacobson
Manager, Environmental

Bradley J. Cooley, P.E.
Director, Environmental

/bmh
Enclosures

Attachment A (Confidential Business Information)

Updated Company-Specific Interest Rate Calculation

The Confidential information in this Attachment meets the conditions of NMAC § 20.2.1.115.B(3), as follows. Enterprise considers the information to be confidential, and requests that it be treated as such to the full extent of applicable law. We have taken reasonable measures to protect the confidentiality by keeping the information in secure data systems that are only available to authorized users, who are subject to confidentiality obligations per company policy, and by making this confidentiality claim. Further, neither NMED nor a third party could obtain the information without our consent, as this is information developed by Enterprise.

Attachment B (Confidential Business Information)

Updated Vendor-Provided Retrofit Cost Information

The Confidential information in this Attachment meets the conditions of NMAC § 20.2.1.115.B(3), as follows. Enterprise considers the information to be confidential, and requests that it be treated as such to the full extent of applicable law. We have taken reasonable measures to protect the confidentiality by keeping the information in secure data systems that are only available to authorized users, who are subject to confidentiality obligations per company policy, and by making this confidentiality claim. Further, neither NMED nor a third party could obtain the information without our consent, as this is information developed by Enterprise.

Attachment C

Updated Cost-Effectiveness Estimates for South Carlsbad

Enterprise Field Services, LLC
South Carlsbad Compressor Station

Solar Centaur T4702 Turbine Unit 1	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
	$SoloNO_X$ Period:	20 years	
Base Emissions			
NO_X ppm:	116.5	ppm	<-- 2022 Stack Test Data
NO_X tpy:	62.07	tpy	<-- 2022 AEIR Data
$SoloNO_X$			
NO_X guarantee:	25	ppm	<-- From Solar
NO_X tpy:	13.32	tpy	
Total Cap Investment	$ 2,616,768		<-- Control System Cost from Solar and estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 317,920		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 74,723		<-- Incremental annual inspection and overhaul costs for unit equipped with $SoloNO_X$
Total Annual Costs:	$ 392,642		
Emissions Reduction:	48.75	tpy	
Cost Effectiveness:	**$ 8,054.67**	**$/ton**	

Enterprise Field Services, LLC
South Carlsbad Compressor Station

Solar Centaur T4702 Turbine Unit 2	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
	SoloNO$_X$ Period:	20 years	
Base Emissions			
NO$_X$ ppm:	111.5	ppm	<-- 2022 Stack Test Data
NO$_X$ tpy:	50.59	tpy	<-- 2022 AEIR Data
SoloNO$_X$			
NO$_X$ guarantee:	25	ppm	<-- From Solar
NO$_X$ tpy:	11.34	tpy	
Total Cap Investment	$ 2,616,768		<-- Control System Cost from Solar and estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 317,920		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 74,723		<-- Incremental annual inspection and overhaul costs for unit equipped with SoloNO$_X$
Total Annual Costs:	$ 392,642		
Emissions Reduction:	39.25	tpy	
Cost Effectiveness:	**$ 10,004.80**	**$/ton**	

TOTAL CAPITAL INVESTEMENT COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
SOUTH CARLSBAD COMPRESSOR STATION

South Carlsbad CS		
Cost Estimation Methodology Used:	**EPA Air Pollution Control Cost Manual Section 5.2, Chapter 1, Table 1.3[1]**	
Unit:	**Unit 1**	**Unit 2**
Control Technology:	**SoloNOx**	**SoloNOx**
Control System Cost (Vendor Estimate):	$ 1,008,000	$ 1,008,000
PEC (Control System Cost*1.18):	$ 1,189,440	$ 1,189,440
DIC (PEC*0.85)	$ 1,011,024	$ 1,011,024
DC (PEC + DIC):	$ 2,200,464	$ 2,200,464
IC (PEC*0.35) :	$ 416,304	$ 416,304
Total Capital Investment (DC+IC):	**$ 2,616,768**	**$ 2,616,768**

[1] https://www.epa.gov/sites/production/files/2020-07/documents/cs5-2ch1.pdf

PEC - Purchased Equipment Cost	Control equipment
DIC - Direct Installation Cost	Foundation/supports, handling/erection, electrical, piping, installation of ductwork, painting
DC - Direct Cost	PEC and DIC
IC - Indirect Cost	Engineering, Construction and field expenses, contractor fees, start-up, performance test, contingencies

DETAILED O&M COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
SOUTH CARLSBAD COMPRESSOR STATION

Facility	Combustion Source	Unit No.	NOx Reduction Technology	*Additional Annual O&M Cost*		
				Hours Between Overhauls	Additional Inspection and Overhaul Costs for SoloNOx Units ($/hr)	Annual Total[1]
South Carlsbad Compressor Station	Solar Centaur T-4702	1	$SoloNO_X$	30,000	$8.53	$74,723
	Solar Centaur T-4702	2	$SoloNO_X$	30,000	$8.53	$74,723

Notes:

[1] Based on incremental costs for new emission control equipment as provided by vendors

Electrification

Enterprise Field Services, LLC
South Carlsbad Compressor Station

Solar Centaur T4702 Turbine Unit 1	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
	Period:	20	years
Base Emissions			
NO_X ppm:		116.5 ppm	<-- 2022 Stack Test Data
NO_X tpy:		62.07 tpy	<-- 2022 AEIR Data
Electric			
NO_X guarantee:		0 ppm	
NO_X tpy:		0.00 tpy	
Total Cap Investment	$ 11,896,689		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,445,368		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ -		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$ 1,445,368		
Emissions Reduction:		62.07 tpy	
Cost Effectiveness:	**$ 23,287.96**	**$/ton**	

Enterprise Field Services, LLC
South Carlsbad Compressor Station

Solar Centaur T4702 Turbine Unit 2	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
	Period:	20 years	
Base Emissions			
NO_X ppm:	111.5	ppm	<-- 2022 Stack Test Data
NO_X tpy:	50.59	tpy	<-- 2022 AEIR Data
Electric			
NO_X guarantee:	0	ppm	
NO_X tpy:	0.00	tpy	
Total Cap Investment	$ 11,896,689		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,445,368		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ -		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$ 1,445,368		
Emissions Reduction:	50.59	tpy	
Cost Effectiveness:	**$ 28,571.35**	**$/ton**	

TOTAL CAPITAL INVESTEMENT COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
SOUTH CARLSBAD COMPRESSOR STATION

South Carlsbad CS		
Cost Estimation Methodology Used:	**EPA Air Pollution Control Cost Manual Section 5.2, Chapter 1, Table 1.3[1]**	
Unit:	**Unit 1**	**Unit 2**
Combustion Unit:	**Solar Centaur T-4702**	**Solar Centaur T-4702**
Electric Infrastructure Cost:	$ 3,043,750	$ 3,043,750
Electric Motor/Compressor Cost:	$ 1,538,950	$ 1,538,950
PEC (Electrification Cost*1.18):	$ 5,407,586	$ 5,407,586
DIC (PEC*0.85)	$ 4,596,448	$ 4,596,448
DC (PEC + DIC):	$ 10,004,034	$ 10,004,034
IC (PEC*0.35) :	$ 1,892,655	$ 1,892,655
Total Capital Investment (DC+IC):	**$ 11,896,689**	**$ 11,896,689**

[1] https://www.epa.gov/sites/production/files/2020-07/documents/cs5-2ch1.pdf

PEC - Purchased Equipment Cost	Control equipment
DIC - Direct Installation Cost	Foundation/supports, handling/erection, electrical, piping, installation of ductwork, painting
DC - Direct Cost	PEC and DIC
IC - Indirect Cost	Engineering, Construction and field expenses, contractor fees, start-up, performance test, contingencies

Attachment D

Updated Cost-Effectiveness Estimates for Blanco

Enterprise Field Services, LLC
Blanco C&D Compressor Station

GE 5221W Turbine	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
Unit T-CO1			
	Water/Steam Injection Period:	15 years	

Base Emissions

NO_X ppm:	41.5	ppm	<-- 2022 Stack Test Data
NO_X tpy:	126.31	tpy	<-- 2022 AEIR Data

Water Injection

NO_X guarantee:	35	ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X tpy:	107.37	tpy	
Total Capital Investment:	$ 10,643,600		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,439,526		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,976,334		<-- Inspection and operating costs
Total Annual Costs:	$ 3,415,860		
Emissions Reduction:	18.95	tpy	
Cost Effectiveness:	**$ 180,285.47**	**$/ton**	

Steam Injection

NO_X guarantee:	35	ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X tpy:	107.37	tpy	
Total Cap Investment	$ 14,018,400		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,895,961		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 2,858,509		<-- Inspection and operating costs
Total Annual Costs:	$ 4,754,469		
**Emissions Reduction:	18.95	tpy	
Cost Effectiveness:	**$ 250,935.87**	**$/ton**	

** Additional NO_X emissions from the boiler are not considered in this emission reduction.

Enterprise Field Services, LLC
Blanco C&D Compressor Station

GE 5221W Turbine Unit T-CO2	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
	Water/Steam Injection Period:	15 years	

Base Emissions

NO_X ppm:		53.4 ppm	<-- 2022 Stack Test Data
NO_X tpy:		142.88 tpy	<-- 2022 AEIR Data

Water Injection

NO_X guarantee:		45 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X tpy:		121.45 tpy	
Total Capital Investment:	$ 10,643,600		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,439,526		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,976,334		<-- Inspection and operating costs
Total Annual Costs:	$ 3,415,860		
Emissions Reduction:		21.43 tpy	
Cost Effectiveness:	**$ 159,383.52**	**$/ton**	

Steam Injection

NO_X guarantee:		45 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X tpy:		121.45 tpy	
Total Cap Investment	$ 14,018,400		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,895,961		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 2,858,509		<-- Inspection and operating costs
Total Annual Costs:	$ 4,754,469		
**Emissions Reduction:		21.43 tpy	
Cost Effectiveness:	**$ 221,842.85**	**$/ton**	

** Additional NO_X emissions from the boiler are not considered in this emission reduction.

Enterprise Field Services, LLC
Blanco C&D Compressor Station

GE M5322B Turbine
Unit T-DO1

Interest Rate:		10.50%	<-- Company-specific interest rate as of 6/30/23
DLN Period:		20 years	
Water/Steam Injection Period:		15 years	

Base Emissions

NO_X ppm:		50.2 ppm	<-- 2022 Stack Test Data
NO_X tpy:		183.65 tpy	<-- 2022 AEIR Data

Dry Low NO_X

NO_X guarantee:		35 ppm	<-- From Baker Hughes
NO_X tpy:		128.04 tpy	
Total Cap Investment	$ 15,576,000		<-- Control System Cost from Baker Hughes; estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,892,379		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 54,829		<-- Incremental overhaul costs
Total Annual Costs:	$ 1,947,208		
Emissions Reduction:		55.61 tpy	
Cost Effectiveness:	**$ 35,017.40**	**$/ton**	

Water Injection

NO_X guarantee:		43 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X tpy:		156.10 tpy	
Total Cap Investment:	$ 10,643,600		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,439,526		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,976,334		<-- Inspection and operating costs
Total Annual Costs:	$ 3,415,860		
Emissions Reduction:		27.55 tpy	
Cost Effectiveness:	**$ 123,999.58**	**$/ton**	

Steam Injection

NO_X guarantee:		43 ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X tpy:		156.10 tpy	
Total Cap Investment	$ 14,018,400		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,895,961		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 2,858,509		<-- Inspection and operating costs
Total Annual Costs:	$ 4,754,469		
Emissions Reduction:		27.55 tpy	
Cost Effectiveness:	**$ 172,592.62**	**$/ton**	

** Additional NO_X emissions from the boiler are not considered in this emission reduction.

TOTAL CAPITAL INVESTEMENT COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
BLANCO C & D COMPRESSOR STATION

Blanco C & D Compressor Station							
Cost Estimation Methodology Used:	**EPA Air Pollution Control Cost Manual Section 5.2, Chapter 1, Table 1.3[1]**						
Unit:	**T-C01**		**T-C02**		**T-D01**		
Control Technology:	**Water Injection**	**Steam Injection**	**Water Injection**	**Steam Injection**	**Dry Low NO_X (DLN)**	**Water Injection**	**Steam Injection**
Control System Cost (Estimate):	$ 4,100,000	$ 5,400,000	$ 4,100,000	$ 5,400,000	$ 6,000,000	$ 4,100,000	$ 5,400,000
PEC (Control System Cost*1.18):	$ 4,838,000	$ 6,372,000	$ 4,838,000	$ 6,372,000	$ 7,080,000	$ 4,838,000	$ 6,372,000
DIC (PEC*0.85)	$ 4,112,300	$ 5,416,200	$ 4,112,300	$ 5,416,200	$ 6,018,000	$ 4,112,300	$ 5,416,200
DC (PEC + DIC):	$ 8,950,300	$ 11,788,200	$ 8,950,300	$ 11,788,200	$ 13,098,000	$ 8,950,300	$ 11,788,200
IC (PEC*0.35) :	$ 1,693,300	$ 2,230,200	$ 1,693,300	$ 2,230,200	$ 2,478,000	$ 1,693,300	$ 2,230,200
Total Capital Investment (DC+IC):	**$ 10,643,600**	**$ 14,018,400**	**$ 10,643,600**	**$ 14,018,400**	**$ 15,576,000**	**$ 10,643,600**	**$ 14,018,400**

[1] https://www.epa.gov/sites/production/files/2020-07/documents/cs5-2ch1.pdf

PEC - Purchased Equipment Cost	Control equipment
DIC - Direct Installation Cost	Foundation/supports, handling/erection, electrical, piping, installation of ductwork, painting
DC - Direct Cost	PEC and DIC
IC - Indirect Cost	Engineering, Construction and field expenses, contractor fees, start-up, performance test, contingencies

DETAILED O&M COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
BLANCO C & D COMPRESSOR STATION

Facility	Combustion Source	Unit No.	NOx Reduction Technology	*Additional Annual O&M Cost*		
				Annual Inspection and Overhaul Costs[1]	Ancillary Equipment O&M Cost (Water Supply/Boiler)[2]	Annual Total
Blanco C&D Compressor Station	GE Frame 5	T-C01	Water Injection	$60,486	$1,915,848	$1,976,334
			Steam Injection	$54,829	$2,803,680	$2,858,509
	GE Frame 5	T-C02	Water Injection	$60,486	$1,915,848	$1,976,334
			Steam Injection	$54,829	$2,803,680	$2,858,509
	GE M5322B	T-D01	Dry Low NO_X (DLN)	$54,829	-	$54,829
			Water Injection	$60,486	$1,915,848	$1,976,334
			Steam Injection	$54,829	$2,803,680	$2,858,509

Notes:

[1] Based on incremental costs for new emission control equipment as provided by vendor.

[2] Ancillary Equipment O&M cost is based on the following:

Water Injection: Annual O&M Costs = 18% of Capital Cost

Steam Injection: Annual O&M Costs = 20% of Capital Cost

Electrification

Enterprise Field Services, LLC
Blanco C&D Compressor Station

GE 5221W Turbines	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
Unit T-CO1			
	Period:	20 years	

Base Emissions			
NO_X ppm:	41.5	ppm	<-- 2022 Stack Test Data
NO_X tpy:	126.31	tpy	<-- 2022 AEIR Data

Electric Conversion			
NO_X guarantee:	0	ppm	
NO_X tpy:	0.00	tpy	
Total Capital Investment:	$ 45,215,322		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 5,493,357		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ -		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$ 5,493,357		
Emissions Reduction:	126.31	tpy	
Cost Effectiveness:	**$ 43,490.04**	**$/ton**	

Enterprise Field Services, LLC
Blanco C&D Compressor Station

GE 5221W Turbines	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
Unit T-CO2			
	Period:	20 years	

Base Emissions			
NO_X ppm:		53.4 ppm	<-- 2022 Stack Test Data
NO_X tpy:		142.88 tpy	<-- 2022 AEIR Data
Electric Conversion			
NO_X guarantee:		0 ppm	
NO_X tpy:		0.00 tpy	
Total Capital Investment:	$	45,215,322	<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	5,493,357	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	-	<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$	5,493,357	
Emissions Reduction:		142.88 tpy	
Cost Effectiveness:	**$**	**38,447.89**	**$/ton**

Enterprise Field Services, LLC
Blanco C&D Compressor Station

GE M5322B Turbine
Unit T-DO1

Interest Rate:	10.50%		<-- Company-specific interest rate as of 6/30/23
Period:	20	years	

Base Emissions

NO_X ppm:	50.2	ppm	<-- 2022 Stack Test Data
NO_X tpy:	183.65	tpy	<-- 2022 AEIR Data

Electric Conversion

NO_X guarantee:	0	ppm	
NO_X tpy:	0.00	tpy	
Total Cap Investment:	$ 63,074,071		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 7,663,075		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ -		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$ 7,663,075		
Emissions Reduction:	183.65	tpy	
Cost Effectiveness:	**$ 41,726.74**	**$/ton**	

TOTAL CAPITAL INVESTEMENT COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
BLANCO C & D COMPRESSOR STATION

Blanco C & D Compressor Station			
Cost Estimation Methodology Used:	**EPA Air Pollution Control Cost Manual Section 5.2, Chapter 1, Table 1.3[1]**		
Unit:	**T-C01**	**T-C02**	**T-D01**
Combustion Unit:	**GE Frame 5**	**GE Frame 5**	**GE M5322B**
Electric Infrastructure Cost:	$ 7,916,667	$ 7,916,667	$ 10,416,667
Electric Motor/Compressor Cost:	$ 9,500,638	$ 9,500,638	$ 13,879,971
PEC (Electrification Cost*1.18):	$ 20,552,419	$ 20,552,419	$ 28,670,032
DIC (PEC*0.85)	$ 17,469,556	$ 17,469,556	$ 24,369,528
DC (PEC + DIC):	$ 38,021,975	$ 38,021,975	$ 53,039,560
IC (PEC*0.35) :	$ 7,193,347	$ 7,193,347	$ 10,034,511
Total Capital Investment (DC+IC):	**$ 45,215,322**	**$ 45,215,322**	**$ 63,074,071**

[1] https://www.epa.gov/sites/production/files/2020-07/documents/cs5-2ch1.pdf

PEC - Purchased Equipment Cost	Control equipment
DIC - Direct Installation Cost	Foundation/supports, handling/erection, electrical, piping, installation of ductwork, painting
DC - Direct Cost	PEC and DIC
IC - Indirect Cost	Engineering, Construction and field expenses, contractor fees, start-up, performance test, contingencies

Attachment E

Updated Cost-Effectiveness Estimates for Chaco

Enterprise Field Services, LLC

Chaco Gas Plant

GE Frame 5 Turbine Unit 17	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
	Water/Steam Injection Period:	15 years	

Base Emissions

NO_X ppm:	32.7	ppm	<-- 2022 Stack Test Data
NO_X tpy:	96.81	tpy	<-- 2022 AEIR Data

Water Injection

NO_X guarantee:	28	ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X tpy:	82.29	tpy	
Total Cap Investment	$ 10,643,600		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,439,526		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,976,334		<-- Inspection and operating costs
Total Annual Costs:	$ 3,415,860		
Emissions Reduction:	14.52	tpy	
Cost Effectiveness:	**$ 235,232.62**	**$/ton**	

Steam Injection

NO_X guarantee:	28	ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X tpy:	82.29	tpy	
Total Cap Investment	$ 14,018,400		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,895,961		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 2,858,509		<-- Inspection and operating costs
Total Annual Costs:	$ 4,754,469		
Emissions Reduction:	14.52	tpy	
Cost Effectiveness:	**$ 327,415.73**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

GE Frame 5 Turbine Unit 18	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
	Water/Steam Injection Period:	15 years	

Base Emissions

NO_X ppm:	34.3	ppm	<-- 2022 Stack Test Data
NO_X tpy:	93.10	tpy	<-- 2022 AEIR Data

Water Injection

NO_X guarantee:	29	ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X tpy:	79.14	tpy	
Total Cap Investment	$ 10,643,600		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,439,526		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 1,976,334		<-- Inspection and operating costs
Total Annual Costs:	$ 3,415,860		
Emissions Reduction:	13.97	tpy	
Cost Effectiveness:	**$ 244,590.98**	**$/ton**	

Steam Injection

NO_X guarantee:	29	ppm	<-- 15% Reduction, AP-42 3.1.4.1
NO_X tpy:	79.14	tpy	
Total Cap Investment	$ 14,018,400		<-- Estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,895,961		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 2,858,509		<-- Inspection and operating costs
Total Annual Costs:	$ 4,754,469		
Emissions Reduction:	13.97	tpy	
Cost Effectiveness:	**$ 340,441.46**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbine Unit 35	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
	$SoloNO_X$ Period:	20 years	

Base Emissions

NO_X ppm:	116	ppm	<-- 2022 Stack Test Data
NO_X tpy:	119.52	tpy	<-- 2022 AEIR Data

$SoLoNO_X$

NO_X guarantee:	15	ppm	<-- From Solar
NO_X tpy:	15.52	tpy	
Total Cap Investment	$ 10,176,320		<-- Control System Cost from Solar and estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,236,354		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 143,839		<-- Incremental annual inspection and overhaul costs for unit equipped with $SoloNO_X$
Total Annual Costs:	$ 1,380,194		
Emissions Reduction:	104.00	tpy	
Cost Effectiveness:	**$ 13,271.73**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbine Unit 36	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
	$SoloNO_X$ Period:	20 years	

Base Emissions

NO_X ppm:	130	ppm	<-- 2022 Stack Test Data
NO_X tpy:	108.34	tpy	<-- 2022 AEIR Data

$SoLoNO_X$

NO_X guarantee:	15	ppm	<-- from Solar
NO_X tpy:	12.50	tpy	
Total Cap Investment	$ 10,176,320		<-- Control System Cost from Solar and estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,236,354		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 143,839		<-- Incremental annual inspection and overhaul costs for unit equipped with $SoloNO_X$
Total Annual Costs:	$ 1,380,194		
Emissions Reduction:	95.83	tpy	
Cost Effectiveness:	**$ 14,401.80**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbine Unit 37	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
	$SoloNO_X$ Period:	20 years	

Base Emissions

NO_X ppm:	122	ppm	<-- 2022 Stack Test Data
NO_X tpy:	72.54	tpy	<-- 2022 AEIR Data

$SoLoNO_X$

NO_X guarantee:	15	ppm	<-- from Solar
NO_X tpy:	8.92	tpy	
Total Cap Investment	$ 10,176,320		<-- Control System Cost from Solar and estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 1,236,354		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 143,839		<-- Incremental annual inspection and overhaul costs for unit equipped with $SoloNO_X$
Total Annual Costs:	$ 1,380,194		
Emissions Reduction:	63.62	tpy	
Cost Effectiveness:	**$ 21,693.94**	**$/ton**	

TOTAL CAPITAL INVESTEMENT COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
CHACO GAS PLANT

Chaco Gas Plant							
Cost Estimation Methodology Used:	**EPA Air Pollution Control Cost Manual Section 5.2, Chapter 1, Table 1.3** [1]						
Unit:	**17**		**18**		**35**	**36**	**37**
Control Technology:	**Water Injection**	**Steam Injection**	**Water Injection**	**Steam Injection**	**SoloNO$_X$**	**SoloNO$_X$**	**SoloNO$_X$**
Control System Cost (Estimate):	$ 4,100,000	$ 5,400,000	$ 4,100,000	$ 5,400,000	$ 3,920,000	$ 3,920,000	$ 3,920,000
PEC (Control System Cost*1.18):	$ 4,838,000	$ 6,372,000	$ 4,838,000	$ 6,372,000	$ 4,625,600	$ 4,625,600	$ 4,625,600
DIC (PEC*0.85)	$ 4,112,300	$ 5,416,200	$ 4,112,300	$ 5,416,200	$ 3,931,760	$ 3,931,760	$ 3,931,760
DC (PEC + DIC):	$ 8,950,300	$ 11,788,200	$ 8,950,300	$ 11,788,200	$ 8,557,360	$ 8,557,360	$ 8,557,360
IC (PEC*0.35) :	$ 1,693,300	$ 2,230,200	$ 1,693,300	$ 2,230,200	$ 1,618,960	$ 1,618,960	$ 1,618,960
Total Capital Investment (DC+IC):	**$ 10,643,600**	**$ 14,018,400**	**$ 10,643,600**	**$ 14,018,400**	**$ 10,176,320**	**$ 10,176,320**	**$ 10,176,320**

[1] https://www.epa.gov/sites/production/files/2020-07/documents/cs5-2ch1.pdf

PEC - Purchased Equipment Cost	Control equipment
DIC - Direct Installation Cost	Foundation/supports, handling/erection, electrical, piping, installation of ductwork, painting
DC - Direct Cost	PEC and DIC
IC - Indirect Cost	Engineering, Construction and field expenses, contractor fees, start-up, performance test, contingencies

DETAILED O&M COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
CHACO GAS PLANT

				Additional Annual O&M Cost				
Facility	**Combustion Source**	**Unit No.**	**NOx Reduction Technology**	**Hours Between Overhauls[1]**	**Additional Inspection and Overhaul Costs for SoloNOx Units ($/hr)[1]**	**Annual Inspection and Overhaul Costs[1]**	**Ancillary Equipment O&M Cost (Water Supply/Boiler)[2]**	**Annual Total**
Chaco Gas Plant	GE Frame 5	17	Water Injection	-	-	$60,486	$1,915,848	$1,976,334
			Steam Injection	-	-	$54,829	$2,803,680	$2,858,509
	GE Frame 5	18	Water Injection	-	-	$60,486	$1,915,848	$1,976,334
			Steam Injection	-	-	$54,829	$2,803,680	$2,858,509
	Solar Mars T-15000	35	$SoloNO_X$	30,000	$16.42	-	-	$143,839
	Solar Mars T-15000	36	$SoloNO_X$	30,000	$16.42	-	-	$143,839
	Solar Mars T-15000	37	$SoloNO_X$	30,000	$16.42	-	-	$143,839

Notes:

[1] Based on incremental costs for new emission control equipment as provided by vendors.

[2] Ancillary Equipment O&M cost is based on the following:

Water Injection: Annual O&M Costs = 18% of Capital Cost

Steam Injection: Annual O&M Costs = 20% of Capital Cost

Electrification

Enterprise Field Services, LLC

Chaco Gas Plant

Clark TLA-10 RICE Unit 12	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
	Period:	20 years	

Base Emissions

NO_X ppm:	253.44	ppm	<-- 2022 Stack Test Data
NO_X tpy:	83.21	tpy	<-- 2022 AEIR Data

Electric Conversion

NO_X guarantee:	0	ppm	
NO_X tpy:	0.00	tpy	
Total Cap Investment	$ 32,982,294		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 4,007,127		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ -		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$ 4,007,127		
Emissions Reduction:	83.21	tpy	
Cost Effectiveness:	**$ 48,156.21**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Clark TLA-10 RICE Unit 13	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
	Period:	20 years	

Base Emissions

NO_X ppm:	198.25	ppm	<-- 2022 Stack Test Data
NO_X tpy:	39.22	tpy	<-- 2022 AEIR Data

Electric Conversion

NO_X guarantee:	0	ppm	
NO_X tpy:	0.00	tpy	
Total Cap Investment	$ 32,982,294		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 4,007,127		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ -		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$ 4,007,127		
Emissions Reduction:	39.22	tpy	
Cost Effectiveness:	**$ 102,178.30**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Clark TLA-10 RICE Unit 14	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
	Period:	20 years	

Base Emissions

NO_X ppm:	270.30	ppm	<-- 2022 Stack Test Data
NO_X tpy:	124.61	tpy	<-- 2022 AEIR Data

Electric Conversion

NO_X guarantee:	0	ppm	
NO_X tpy:	0.00	tpy	
Total Cap Investment	$ 32,982,294		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 4,007,127		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ -		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$ 4,007,127		
Emissions Reduction:	124.61	tpy	
Cost Effectiveness:	**$ 32,156.83**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

GE Frame 5 Turbine Unit 17	Interest Rate:		10.50%	<-- Company-specific interest rate as of 6/30/23
	Period:		20	years
Base Emissions				
NO_X ppm:		32.7	ppm	<-- 2022 Stack Test Data
NO_X tpy:		96.81	tpy	<-- 2022 AEIR Data
Electric Conversion				
NO_X guarantee:		0	ppm	
NO_X tpy:		0.00	tpy	
Total Cap Investment	$	58,376,533		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	7,092,356		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	-		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$	7,092,356		
Emissions Reduction:		96.81	tpy	
Cost Effectiveness:	**$**	**73,262.08**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

GE Frame 5 Turbine Unit 18	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
	Period:	20 years	

Base Emissions

NO_X ppm:	34.3	ppm	<-- 2022 Stack Test Data
NO_X tpy:	93.10	tpy	<-- 2022 AEIR Data

Electric Conversion

NO_X guarantee:	0	ppm	
NO_X tpy:	0.00	tpy	
Total Cap Investment	$ 58,376,533		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 7,092,356		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ -		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$ 7,092,356		
Emissions Reduction:	93.10	tpy	
Cost Effectiveness:	**$ 76,176.70**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbine Unit 35	Interest Rate:		10.50%	<-- Company-specific interest rate as of 6/30/23
	Period:		20	years
Base Emissions				
NO_X ppm:		116	ppm	<-- 2022 Stack Test Data
NO_X tpy:		66.85	tpy	<-- 2022 AEIR Data
Electric Conversion				
NO_X guarantee:		0	ppm	
NO_X tpy:		0.00	tpy	
Total Cap Investment	$	53,395,069		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	6,487,141		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	-		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$	6,487,141		
Emissions Reduction:		66.85	tpy	
Cost Effectiveness:	**$**	**97,035.90**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbine Unit 36	Interest Rate:	10.50%	<-- Company-specific interest rate as of 6/30/23
	Period:	20 years	

Base Emissions

NO_X ppm:	130	ppm	<-- 2022 Stack Test Data
NO_X tpy:	122.96	tpy	<-- 2022 AEIR Data

Electric Conversion

NO_X guarantee:	0	ppm	
NO_X tpy:	0.00	tpy	
Total Cap Investment	$ 53,395,069		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$ 6,487,141		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ -		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$ 6,487,141		
Emissions Reduction:	122.96	tpy	
Cost Effectiveness:	**$ 52,758.39**	**$/ton**	

Enterprise Field Services, LLC

Chaco Gas Plant

Mars T-15000 Turbine Unit 37	Interest Rate:		10.50%	<-- Company-specific interest rate as of 6/30/23
	Period:		20	years
Base Emissions				
NO_X ppm:		122	ppm	<-- 2022 Stack Test Data
NO_X tpy:		72.54	tpy	<-- 2022 AEIR Data
Electric Conversion				
NO_X guarantee:		0	ppm	
NO_X tpy:		0.00	tpy	
Total Cap Investment	$	53,395,069		<-- Electrical infrastructure cost from Enterprise Entergy Utilization Group, cost of electric driven compressor derived from a proxy unit (at $426.42/HP). Total Capital Investment estimated using EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.3
Annualized TCI:	$	6,487,141		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	-		<-- Incremental annual inspection and overhaul costs assumed to be negligible compared to a combustion unit
Total Annual Costs:	$	6,487,141		
Emissions Reduction:		72.54	tpy	
Cost Effectiveness:	**$**	**89,428.47**	**$/ton**	

TOTAL CAPITAL INVESTEMENT COST SUMMARY OF NO_X REDUCTION TECHNOLOGIES
NEW MEXICO REGIONAL HAZE FOUR-FACTOR ANALYSIS
CHACO GAS PLANT

Chaco Gas Plant								
Cost Estimation Methodology Used:	**EPA Air Pollution Control Cost Manual Section 5.2, Chapter 1, Table 1.3[1]**							
Unit:	**12**	**13**	**14**	**17**	**18**	**35**	**36**	**37**
Combustion Unit:	**Clark TLA-10**	**Clark TLA-10**	**Clark TLA-10**	**GE Frame 5**	**GE Frame 5**	**Mars T-15000**	**Mars T-15000**	**Mars T-15000**
Electric Infrastructure Cost:	$ 11,255,208	$ 11,255,208	$ 11,255,208	$ 14,171,875	$ 14,171,875	$ 14,171,875	$ 14,171,875	$ 14,171,875
Electric Motor/Compressor Cost:	$ 1,449,836	$ 1,449,836	$ 1,449,836	$ 8,315,233	$ 8,315,233	$ 6,396,333	$ 6,396,333	$ 6,396,333
PEC (Electrification Cost*1.18):	$ 14,991,952	$ 14,991,952	$ 14,991,952	$ 26,534,788	$ 26,534,788	$ 24,270,486	$ 24,270,486	$ 24,270,486
DIC (PEC*0.85)	$ 12,743,159	$ 12,743,159	$ 12,743,159	$ 22,554,570	$ 22,554,570	$ 20,629,913	$ 20,629,913	$ 20,629,913
DC (PEC + DIC):	$ 27,735,111	$ 27,735,111	$ 27,735,111	$ 49,089,357	$ 49,089,357	$ 44,900,399	$ 44,900,399	$ 44,900,399
IC (PEC*0.35) :	$ 5,247,183	$ 5,247,183	$ 5,247,183	$ 9,287,176	$ 9,287,176	$ 8,494,670	$ 8,494,670	$ 8,494,670
Total Capital Investment (DC+IC):	**$ 32,982,294**	**$ 32,982,294**	**$ 32,982,294**	**$ 58,376,533**	**$ 58,376,533**	**$ 53,395,069**	**$ 53,395,069**	**$ 53,395,069**

[1] https://www.epa.gov/sites/production/files/2020-07/documents/cs5-2ch1.pdf

PEC - Purchased Equipment Cost	Control equipment
DIC - Direct Installation Cost	Foundation/supports, handling/erection, electrical, piping, installation of ductwork, painting
DC - Direct Cost	PEC and DIC
IC - Indirect Cost	Engineering, Construction and field expenses, contractor fees, start-up, performance test, contingencies

D.5 ET Gathering & Processing

Supporting documentation for ET Gathering & Processing is provided below. Facility-specific documentation is provided first, followed by documentation pertaining to multiple facilities and/or the owner/operator. The following documents are included in this section (in reading order):

- Jal #3 Gas Plant:
    - Settlement Agreement and Stipulated Final Compliance Order (8/30/2021)
    - SRU Shutdown Certification (10/12/2021)
    - Administrative Permit Revisions (10/27/2021)
    - Application for Significant Revision to NSR Permit (6/10/2022)
    - NSR Permit No. 1092-M10 (11/7/2022)

STATE OF NEW MEXICO
SECRETARY OF ENVIRONMENT

ENVIRONMENTAL PROTECTION DIVISION OF THE NEW MEXICO ENVIRONMENT DEPARTMENT,

Complainant,

v. **No. AQB 20-63 (CO)**

ETC TEXAS PIPELINE, LTD.,

Respondent.

SETTLEMENT AGREEMENT AND STIPULATED FINAL COMPLIANCE ORDER

This Settlement Agreement and Stipulated Final Compliance Order ("Final Order") is entered into between the Environmental Protection Division ("Division") of the New Mexico Environment Department ("Department" or "NMED") and Respondent, ETC Texas Pipeline, Ltd., ("ETC") (collectively, the "Parties") to resolve alleged statutory, regulatory, and permit violations by ETC at its Jal No. 3 Gas Plant, located in Lea County, New Mexico. The Department alleges violations of the New Mexico Air Quality Control Act ("AQCA"), NMSA 1978, Sections 74-2-1 to -17; the Air Quality Control Regulations ("Regulations") at Title 20, Chapter 2 NMAC, and Air Quality Permit Number P090-R2M1 ("Permit").

I. BACKGROUND

A. PARTIES

1. The Division is an organizational unit of the Department and has been delegated the authority to issue compliance orders under the AQCA, NMSA 1978, 74-2-12.A (2006). The Air Quality Bureau ("Bureau") is an organizational unit of the Division.

2. ETC is a limited partnership doing business in New Mexico at the Jal No. 3 Gas

Plant Facility ("Facility"), located in Lea County, New Mexico. The Facility is a natural gas processing facility. At all times relevant to this Final Order, ETC owned and operated the Facility.

B. HISTORY AND ALLEGED VIOLATIONS

3. From December 23, 2014 to March 27, 2019, the Facility was authorized to operate under Title V Permit P090R2M1.

4. The following table from Title V Permit P090R2M1, Condition A106 lists the Facility emission units and their allowable emission limits. *See*: 40 CFR 50, 40 CFR 60, Subparts A, Db, and JJJJ, 40 CFR 63, Subparts A and ZZZZ, 40 CFR 64 CAM, 20.2.33 NMAC, 20.2.35 NMAC, 20.2.37 NMAC, and 20.2.72.210.A and B.1 NMAC and NSR Permit 1092-M8.

Table 106.A: Allowable Emissions

Unit No.	NOx[1] pph	NOx tpy	CO pph	CO tpy	VOC pph	VOC tpy	SO_2 pph	SO_2 tpy	TSP/ PM_{10}/ $PM_{2.5}$ pph	TSP/ PM_{10}/ $PM_{2.5}$ tpy
1A	4.9	21.2	6.1	26.6	2.4	10.6	<	<	<	1.6
2A	4.9	21.2	6.1	26.6	2.4	10.6	<	<	<	1.6
3A	4.9	21.2	6.1	26.6	2.4	10.6	<	<	<	1.6
4A	27.9	122.0	11.4	50.1	1.2	5.2	<	<	<	1.6
5A	27.9	122.0	11.4	50.1	1.2	5.2	<	<	<	1.6
C1	3.9	17.1	2.1	9.4	1.7	7.7	<	1.7	<	1.2
C2	3.9	17.1	2.1	9.4	1.7	7.7	<	1.7	<	1.2
C3	3.9	17.1	2.1	9.4	1.7	7.7	<	1.7	<	1.2
C4	3.9	17.1	2.1	9.4	1.7	7.7	<	1.7	<	1.2
S1	8.8	39.0	3.0	13.1	3.5	15.5	<	1.4	<	3.6
S2	8.8	39.0	3.0	13.1	3.5	15.5	<	1.4	<	3.6
S3	8.8	39.0	3.0	13.1	3.5	15.5	<	1.4	<	3.6
S4	8.8	39.0	3.0	13.1	3.5	15.5	<	1.4	<	3.6
S5	8.3	36.2	2.1	9.3	1.3	5.8	<	1.0	<	2.7
7H	< [2]	2.4	<	2.0	<	<	<	<	<	<
9S	3.5	15.4	146.6	642.3	1.1	4.8	275.3	1205.9	<	<
11H	<	3.3	<	2.8	<	<	<	<	<	<
31B	3.3	14.3	3.4	14.7	<	4.0	1.3	5.7	<	4.0
32B	4.7	20.6	10.0	43.6	<	2.9	1.7	7.4	<	3.9
8F	0.05	0.22	0.04	0.18	0.0	0.1	<	<	<	<
9F	0.25	1.1	2.0	8.8	2.2	9.5	<	<	<	<
10F	0.08	0.33	0.06	0.28	0.0	0.1	<	<	<	<

Unit No.	NOx[1] pph	NOx tpy	CO pph	CO tpy	VOC pph	VOC tpy	SO_2 pph	SO_2 tpy	TSP/ PM_{10}/ $PM_{2.5}$ pph	TSP/ PM_{10}/ $PM_{2.5}$ tpy
TK 1	-	-	-	-	*	2.2	-	-	-	-
TK 2	-	-	-	-	*	1.2	-	-	-	-
TK 3	-	-	-	-	*	<	-	-	-	-
TK 4	-	-	-	-	*	<	-	-	-	-
TK 46	-	-	-	-	*	0.2	-	-	-	-
FUG1	-	-	-	-	*	34.8 [3]	-	-	-	-
FUG2	-	-	-	-	*	0.6 [3]	-	-	-	-
Loadout	-	-	-	-	<	6.4	-	-	-	-

1 Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2
2 "<" Indicates the application represented uncontrolled emissions are less than 1.0 pph or 1.0 tpy for this pollutant. Allowable limits are not imposed on this level of emissions, except for flares and pollutants with controls.
"-" Indicates the application represented emissions of this pollutant are not expected.
"*" Indicates hourly emission limits are not appropriate for this operating situation
3 FUG1 emissions are vented to Flares 8F or 10F; FUG2 emissions are vented to Flare 9F.

5. The following table from Title V Permit P090R2M1, Condition A107, lists the facility-wide startup, shutdown, and maintenance, and malfunction emission limits:

Table 107.A: Allowable SSM and Malfunction Units, Activities, and Emission Limits

Unit No.	Description	[1]NOx pph	NOx tpy	CO pph	CO tpy	VOC pph	VOC tpy	SO_2 pph	SO_2 tpy	H_2S pph	H_2S tpy
Flare Unit 9F SSM [4]	Flare Combustion of SSM Emissions	2.0	7.6	16.4	25.1	0.4	6.6	3,820.9	130.4[3]	40.6	1.5
Flare Unit 10F SSM [4]	Non-turbine Flare Combustion of SSM Emissions	430.1[2]		1,630.6[2]		1,008.6[2]		2,773.2[2]		29.5[2]	
Flare Unit 10F SSM	Turbine SSMs to 10F		12.0		26.4		25.6		70.0		4.7
C1 – C4 SSM [5]	C1 – C4 SSM			21.5	2.1	5.0	0.5				
Malfunc-tion	Malfunction Emissions	*[3]	10.0	*[3]	10.0	*[3]	10.0	*[3]	10.0	*[3]	10.0
Totals[6]			29.6		63.6		42.7		210.4		16.2

Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2.
Indicates that non-turbine and turbine to flare pph emissions shall not exceed this rate.
'*" Indicates that the Malfunction emission rates shall not exceed the combined pph SSM emission limits for Units 9F and 10F.

his allowable SSM emission limit does not supersede emission standards required by 40 CFR 60, Subpart JJJJ and/or 40 CFR 63, part ZZZZ.

6. Between January 1, 2017 and August 31, 2018, ETC reported 685 excess emissions events for the Facility via the NMED Air Quality Bureau's online Compliance Reporting System. The originally reported excess emissions totaled 3,131,006 pounds, which amount was later changed to 2,444,736 pounds based on ETC's submittal of corrected excess emissions reports.

7. ETC claimed that eleven (11) of these events qualified as malfunctions under the Environmental Improvement Board's excess emission rule, 20.2.7.111 NMAC. The Department accepted three (3) of these affirmative defense demonstrations ("ADDs"), and rejected the remaining eight (8).

8. On August 26, 2020, the Division issued an Administrative Compliance Order consolidating all the alleged violations identified in the five Notices of Violation issued from June 2017 to November 2018.

9. On September 11, 2020, the Division issued a Corrected Administrative Compliance Order ("ACO"). The recalculated penalty amount is $2,604,695.02.

10. On September 28, 2020, ETC filed its Request for Hearing and Answer to Administrative Compliance Order. ETC requested that the Secretary dismiss the ACO with prejudice.

11. On November 13, 2020, the Department issued a Notice of Docketing and the assignment of a hearing officer.

II. COMPROMISE AND SETTLEMENT

A. GENERAL

12. Following good faith settlement negotiations to resolve this matter without further costly litigation, the Parties agreed to a complete settlement of all the violations alleged in the

ACO, and have consented to the terms of this Final Order. ETC does not admit any of the violations alleged in the ACO, and the Department does not concede that ETC met its burden on the ADDs.

13. The Parties admit jurisdiction and consent to the relief specified herein.

B. CIVIL PENALTY AND ADDITIONAL INJUNCTIVE RELIEF

14. In compromise and settlement of the alleged violations in the ACO, and upon consideration of the seriousness of the alleged violations and ETC's efforts to address the causes of excess emissions at the Facility, the Parties agree that ETC shall: (1) pay a civil penalty of $1,302,347.51 in a cash payment to the State of New Mexico; (2) permanently shut down the sulfur recovery unit ("SRU") at the Facility; and (3) submit an application to revise the NSR and Title V permits for the Facility to remove authorization to operate the SRU.

Civil Penalty

15. ETC shall pay a civil penalty of $1,302,347.51 to the State of New Mexico within 30 calendar days after the effective date of this Final Order.

16. Payment shall be made to the ***State of New Mexico General Fund, New Mexico Environment Department, Air Quality Bureau, 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico,*** by certified or corporate check, or by ACH deposit. On the date that delivery of funds by check or ACH is confirmed, ETC shall notify the Air Quality Bureau Enforcement Manager by electronic mail sent to: cindy.hollenberg@state.nm.us.

Certified or corporate checks shall be sent to the following address:

New Mexico Environment Department
Air Quality Bureau
c/o Compliance and Enforcement Manager
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505

ACH deposits shall be made to the order of the Wells Fargo Bank as follows:

Wells Fargo Bank, N.A.
100 W. Washington Street, Floor 20
Phoenix, AZ. 85003

Routing Transit Number: 121000248
Deposit Account Number: 4123107799
Descriptor: NMED-AQB-C&E

17. If ETC fails to make timely and complete payment of the civil penalty pursuant to paragraph 15, and unless the Parties agree to extend the time for payment of the civil penalty, ETC shall pay a stipulated penalty of $1,500.00 per day for each day the payment is not timely or complete.

Shutdown of SRU

18. Within 60 days of the effective date of this Final Order, ETC shall permanently shut down the sulfur recovery unit ("SRU") at the Facility. Upon completion of the shutdown of the SRU, ETC shall, within 30 days of such completion, submit a written certification to the Department that the SRU was properly and permanently decommissioned in accordance with applicable laws and rules. Certification shall include the following statement, signed by ETC's responsible official:

> *I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I have no personal knowledge that the information submitted is other than true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fines and/or revocation of air quality operating permits for knowingly and willfully submitting a materially false statement.*

19. If ETC fails to permanently shut down the SRU at the Facility within 60 days of the effective date of this Final Order, and unless the Parties agree to extend the time by which ETC

must permanently shut down the SRU, ETC shall pay a stipulated penalty of $1,500.00 per day for each day thereafter until the date the SRU is completely and permanently shut down.

20. If ETC fails to submit the written certification specified in paragraph 18 within 30 days of permanently shutting down the SRU, and unless the Parties agree to extend the time by which ETC must submit the written certification, ETC shall pay a stipulated penalty of $1,500.00 per day for each day thereafter until the date the required certification is submitted.

21. Within 60 days of the permanent shutdown of the SRU, ETC will submit an administrative revision pursuant to 20.2.72.219.A NMAC to the NSR and Title V permits to remove authorization to operate the SRU and any monitoring, recordkeeping, and reporting requirements related to operation of the SRU.

III. OTHER TERMS AND CONDITIONS

A. RESERVATION OF RIGHTS AND DEFENSES

22. This Final Order shall not be construed to prohibit or limit the Division in any way from requiring ETC to comply with any applicable state or federal requirement not resolved herein. This Final Order shall not be construed to prohibit or limit the Division in any way from seeking any relief authorized by the AQCA for violation of any state or federal requirement applicable to ETC not resolved herein. This Final Order shall not be construed to prohibit or limit in ETC in any way from raising any defense to a Department action seeking such relief.

B. MUTUAL RELEASE

23. The Parties mutually release each other from all claims that each Party raised or could have raised against the other regarding the facts and violations alleged in the NOVs and the ACO. Such release applies only to civil liability.

C. WAIVER OF STATE LIABILITY

24. ETC shall assume all costs and liabilities incurred in performing all obligations under this Final Order. The Division, on its own behalf and on behalf of the State of New Mexico, does not assume any liability for ETC's performance of any obligation under this Final Order.

D. EFFECTIVE DATE AND TERMINATION DATES

25. This Final Order and any modifications thereto shall be effective when the Final Order or modification has been executed by both of the Parties.

26. Except as otherwise provided in this Paragraph, the terms of this Final Order shall terminate when ETC has fulfilled the requirements of this Final Order. The reservations of rights and defenses and the mutual release in Paragraphs 22 and 23 shall survive the execution and performance of this Final Order, and shall remain in full force and effect as an agreement between the Parties.

E. INTEGRATION

27. This Final Order merges all prior written and oral communications between the Parties concerning the subject matter of this Final Order, contains the entire agreement between the Parties, and shall not be modified without the express written agreement of the Parties.

F. BINDING EFFECT

28. This Final Order shall be binding on the Parties and their officers, directors, employees, agents, subsidiaries, successors, assigns, trustees, or receivers.

G. AUTHORITY OF SIGNATORIES

29. The persons executing this Final Order on behalf of ETC and the Division, respectively, represent that they have the authority to execute this Final Order on behalf of ETC and the Department.

H. SIGNATURE AND COUNTERPARTS

30. This Final Order is intended to be executed on separate signature pages. Faxed, emailed, electronic, or digital signatures shall constitute original signatures binding on the signing party.

31. This Final Order may be executed in multiple counterparts, each of which shall be deemed an original, but all of which shall constitute one and the same agreement.

ETC TEXAS PIPELINE, LTD
By: LG PL, LLC, its general partner

By: _____ **Date:** 8.25.21

Print Name: Clint Green

Print Title: Vice President, Operations

NEW MEXICO ENVIRONMENT DEPARTMENT

Rebecca Roose

Digitally signed by Rebecca Roose
Date: 2021.08.30 13:54:31 -06'00'

By: _____ **Date:** _____

JAMES C. KENNEY
SECRETARY

ENERGY TRANSFER

***via* FedEx**

October 12, 2021

New Mexico Environment Department
Air Quality Bureau
Compliance and Enforcement Manager
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

RE: **ETC Texas Pipeline, Ltd.**
Final Order No. AQB 20-63 (CO)
Jal #3 Gas Plant

In accordance with the Final Order between the Environmental Protection Division of the New Mexico Environment Department and ETC Texas Pipeline, Ltd. (ETC), dated August 30, 2021, ETC is hereby providing written certification to the Department that the Sulfur Recovery Unit (SRU) at the Jal #3 Gas Plant was properly and permanently decommissioned in accordance with applicable laws and rules. In accordance with section, "Shutdown of SRU" (Paragraph 18), the SRU was permanently shutdown on October 8, 2021, within 60 days of the effective date of the Final Order. This written certification is being submitted within 30 days of the shutdown. Pursuant to Paragraph 21 of the Final Order, ETC is currently working on the submittal of an administrative revision (20.2.72.219.A NMAC) to the NSR (1092-M8) and Title V (P090R3) permits to remove authorization to operate the SRU, including any monitoring, recordkeeping, and reporting requirements related to the operation of the SRU.

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I have no personal knowledge that the information submitted is other than true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fines and/or revocation of air quality operating permits for knowingly and willfully submitting a materially false statement.

Clint Green
VP Operations

RECEIVED
OCT 20 2021
Air Quality Bureau

ENERGY TRANSFER

RECEIVED
OCT 28 2021
Air Quality Bureau

***via* FedEx**

October 27, 2021

New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico, 87505-1816

RE: **Administrative Permit Revisions**
ETC Texas Pipeline, Ltd.
Jal #3 Gas Plant
NSR Permit No. 1092-M8R3
Title V Permit No. P090-R3

Dear Sir/Madam,

On August 25, 2021, ETC Texas Pipeline, Ltd (ETC) entered into the Settlement Agreement and Stipulated Final Compliance Order No. AQB 20-63 (CO) with the New Mexico Environment Department. Condition #21 of this agreement states the following:

> "Within 60 days of the permanent shutdown of the SRU, ETC will submit an administrative revision pursuant to 20.2.72.219.A NMAC to the NSR and Title V permits to remove authorization to operate the SRU and any monitoring, recordkeeping, and reporting requirements related to operation of the SRU."

To satisfy this requirement, ETC is hereby submitting the enclosed Permitting Administrative Multi-Forms requesting that unit numbers SRU and 9S and associated emissions be removed from NSR Permit No. 1092-M8R3 and Title V Permit No. P090-R3. Each form includes a notarized certification that has been signed by the site's Alternate Responsible Official. No changes to facility throughput or other permitted equipment result from the shutdown of these units.

Should you have any questions or require additional information, please do not hesitate to contact me at (432) 238-8421 or carolyn.blackaller@energytransfer.com.

Sincerely,

Carolyn J. Blackaller
Sr. Environmental Specialist

Permitting Administrative Multi-Form

Use for NSR administrative permit revisions (including GCPs), TV administrative amendments, TV responsible official notifications, and other submittals required by a permit condition. Refer to Section 4 for instructions, acronyms, and mailing addresses.

For Department use only:		**For Department use only:**
Reviewed by: Urshula Bajracharya Urshula Bajracharya Digitally signed by Urshula Bajracharya Date: 2021.11.09 15:43:18 -07'00'		Received Date RECEIVED OCT 28 2021 Air Quality Bureau
Permit revision number: 1092-M8R7		
Date: 11/9/2021		
☒ Approved ☐ Completed ☐ Denied		

Section 1: General Information – Required for All Submittals

1	Facility Name: Jal No. 3 Gas Plant		
2	Preparer/Consultant Name: Rita Zebian	Title: Sr. Project Manager	
3	Email: rita.zebian@altamira-us.com	Phone: (817) 617-2675	
4	Address: Altamira, 2301 E. Lamar Blvd., Suite 200, Arlington, TX 76006		
5	Air Permit Contact: Carolyn Blackaller	Title: Sr. Environmental Specialist	
6	Email: carolyn.blackaller@energytransfer.com	Phone: (432) 203-8920	
7	Address: ETC, 600 N Marienfeld St, Suite 700, Midland, TX 79701		
8	Check all boxes below for which this submittal applies:	AI #: 569	Permit #: **P090-R3**

☐ NSR Construction Permit (20.2.72 NMAC) ☒ TV Operating Permit (20.2.70 NMAC)	☐ NOI (20.2.73 NMAC) (Sections 2-B, 2-D) ☐ Notice of Exemption (20.2.72.202.B NMAC) (Section 2-F)	☐ PSD Permit (20.2.74 NMAC) ☐ Nonattainment Permit (20.2.79 NMAC)

Section 2: Details of Submittal

Only print and submit the pages necessary for your submittal. Print double sided head-to-toe, flip on short end (tablet). The Permit Section responds to all TV Administrative amendments and responds only to denials of NSR administrative revisions. Courier proof of delivery is required if you want confirmation that the Department received this submittal. Check the box(es) applicable to this submittal:

☐ 2-A(i) & 2-A(ii): Identical Engine or Turbine Replacements

☐ 2-B: Owner, Operator, and Name Changes to NOIs or Construction Permits

☐ 2-C: Ownership or Operational Control Changes for Title V Permits

☒ 2-D: Closing a Facility or Removing Units from a Permit or Canceling an NOI

☐ 2-E: Correct Typographical Error

☐ 2-F: Reporting Exempt Equipment for Minor Construction Permits or for No Permit Required (NPR) Facilities

☐ 2-G: Add Minor NSR Exempt Equipment to Construction Permits for PSD or Nonattainment Sources

☐ 2-H: Title V Responsible Official Designations

☐ 2-I: Submittals to the Permit Programs Manager

Section 3: Certification – Required for All Changes

Section 4: Form Instructions

Section 2-D: Closing a Facility, Removing Units from a Permit, or Canceling an NOI

(Administrative Revision)

Check the appropriate boxes and provide complete information in the table. Closing the permit does not relieve the permittee from any outstanding permit fees.

If any of the units being removed are emission control equipment explain how a permit, federal regulation, or state regulation will not be violated by removal of the control equipment.

☐ Cease operations of the entire facility and cancel the construction permit (20.2.72.219.A(1)(c) NMAC).

Date the facility ceased operating:

☐ Retire an emissions unit and remove it from the construction permit (20.2.72.219.A(1)(c) NMAC).

Date unit(s) retired:
List all retired unit numbers to be removed from the permit:

☐ Cancel a construction permit for a facility or remove an emissions unit that has not and will not be constructed (20.2.72.219.A(1)(d) NMAC).

☐ Facility (plant) will not be constructed, or	☐ The following units will not be constructed and should be removed from the permit:

☒ Retire an emissions unit and remove it from the TV permit (20.2.70.404.A(1)(c) NMAC).

Date unit(s) retired: October 8, 2021
List all retired unit numbers to be removed from the permit: SRU, 9S

☐ Voluntary Discontinuation of the TV permit (20.2.70.400.I NMAC).

Date the TV permit was no longer required:
Explanation:

☐ Cancel a construction permit that is no longer required.

Explanation:

☐ Removal of minor NSR exempt equipment.

Explanation:

☐ Cancel a Notice of Intent (check one or explain):

☐ PER is now below 20.2.73.200 NMAC threshold.	☐ Date the facility ceased operating:

Section 3: Certification – Required for All Submittals

Company Name: ETC Texas Pipeline, Ltd.

I, Mike McCracken, hereby certify that the information and data submitted in this application are true and as accurate as possible, to the best of my knowledge and professional expertise and experience.

Signed this 27th day of October, 2021, upon my oath or affirmation, before a notary of the State of Texas.

Signature[1] Date 10/27/2021

Mike McCracken Sr. Operations Director

Printed Name Title

Scribed and sworn before me on this 27th day of October, 2021.

My authorization as a notary of the State of Texas expires on the 10th day of November, 2024.

Notary's Signature Date 10.27.21

Dona J. Meadows

Notary's Printed Name

DONA J. MEADOWS
My Notary ID # 6555569
Expires November 10, 2024

[1] For Title V applications, the signature must be of the Responsible Official as defined in 20.2.70.7.AE NMAC:

Permitting Administrative Multi-Form

Use for NSR administrative permit revisions (including GCPs), TV administrative amendments, TV responsible official notifications, and other submittals required by a permit condition. Refer to Section 4 for instructions, acronyms, and mailing addresses.

For Department use only:		**For Department use only:**
Reviewed by:		Received Date
Permit revision number:		
Date:		
☐ Approved ☐ Completed ☐ Denied		

Section 1: General Information – Required for All Submittals

1	Facility Name: Jal No. 3 Gas Plant		
2	Preparer/Consultant Name: Rita Zebian	Title: Sr. Project Manager	
3	Email: rita.zebian@altamira-us.com	Phone: (817) 617-2675	
4	Address: Altamira, 2301 E. Lamar Blvd., Suite 200, Arlington, TX 76006		
5	Air Permit Contact: Carolyn Blackaller	Title: Sr. Environmental Specialist	
6	Email: carolyn.blackaller@energytransfer.com	Phone: (432) 203-8920	
7	Address: ETC, 600 N Marienfeld St, Suite 700, Midland, TX 79701		
8	Check all boxes below for which this submittal applies:	AI #: 569	Permit #: **1092-M8R3**

☒NSR Construction Permit (20.2.72 NMAC) ☐ TV Operating Permit (20.2.70 NMAC)	☐ NOI (20.2.73 NMAC) (Sections 2-B, 2-D) ☐ Notice of Exemption (20.2.72.202.B NMAC) (Section 2-F)	☐ PSD Permit (20.2.74 NMAC) ☐ Nonattainment Permit (20.2.79 NMAC)

Section 2: Details of Submittal

Only print and submit the pages necessary for your submittal. Print double sided head-to-toe, flip on short end (tablet). The Permit Section responds to all TV Administrative amendments and responds only to denials of NSR administrative revisions. Courier proof of delivery is required if you want confirmation that the Department received this submittal. Check the box(es) applicable to this submittal:

☐ 2-A(i) & 2-A(ii): Identical Engine or Turbine Replacements

☐ 2-B: Owner, Operator, and Name Changes to NOIs or Construction Permits

☐ 2-C: Ownership or Operational Control Changes for Title V Permits

☒ 2-D: Closing a Facility or Removing Units from a Permit or Canceling an NOI

☐ 2-E: Correct Typographical Error

☐ 2-F: Reporting Exempt Equipment for Minor Construction Permits or for No Permit Required (NPR) Facilities

☐ 2-G: Add Minor NSR Exempt Equipment to Construction Permits for PSD or Nonattainment Sources

☐ 2-H: Title V Responsible Official Designations

☐ 2-I: Submittals to the Permit Programs Manager

Section 3: Certification – Required for All Changes

Section 2-D: Closing a Facility, Removing Units from a Permit, or Canceling an NOI

(Administrative Revision)

Check the appropriate boxes and provide complete information in the table. Closing the permit does not relieve the permittee from any outstanding permit fees.

If any of the units being removed are emission control equipment explain how a permit, federal regulation, or state regulation will not be violated by removal of the control equipment.

☐ Cease operations of the entire facility and cancel the construction permit (20.2.72.219.A(1)(c) NMAC).

Date the facility ceased operating:

☒ Retire an emissions unit and remove it from the construction permit (20.2.72.219.A(1)(c) NMAC).

Date unit(s) retired: October 8, 2021
List all retired unit numbers to be removed from the permit: SRU, 9S

☐ Cancel a construction permit for a facility or remove an emissions unit that has not and will not be constructed (20.2.72.219.A(1)(d) NMAC).

☐ Facility (plant) will not be constructed, or	☐ The following units will not be constructed and should be removed from the permit:

☐ Retire an emissions unit and remove it from the TV permit (20.2.70.404.A(1)(c) NMAC).

Date unit(s) retired:
List all retired unit numbers to be removed from the permit:

☐ Voluntary Discontinuation of the TV permit (20.2.70.400.I NMAC).

Date the TV permit was no longer required:
Explanation:

☐ Cancel a construction permit that is no longer required.

Explanation:

☐ Removal of minor NSR exempt equipment.

Explanation:

☐ Cancel a Notice of Intent (check one or explain):

☐ PER is now below 20.2.73.200 NMAC threshold.	☐ Date the facility ceased operating:

Section 3: Certification – Required for All Submittals

Company Name: ETC Texas Pipeline, Ltd.

I, Mike McCracken, hereby certify that the information and data submitted in this application are true and as accurate as possible, to the best of my knowledge and professional expertise and experience.

Signed this 27th day of October, 2021, upon my oath or affirmation, before a notary of the State of Texas.

Signature[1] Date: 10/27/2021

Mike McCracken — Printed Name

Sr. Operations Director — Title

Scribed and sworn before me on this 27th day of October, 2021.

My authorization as a notary of the State of Texas expires on the 10th day of November, 2024.

Dona J. Meadows — Notary's Signature — Date: 10.27.21

Dona J. Meadows — Notary's Printed Name

DONA J. MEADOWS
My Notary ID # 6555569
Expires November 10, 2024

[1] For Title V applications, the signature must be of the Responsible Official as defined in 20.2.70.7.AE NMAC:

ALTAMIRA

June10, 2022

New Mexico Environment Department
Air Quality Bureau, Permits Section
525 Camino de los Marquez, Ste. 1
Santa Fe, New Mexico 87505
(505) 476-4300

RECEIVED
JUN 13 2022
Air Quality Bureau

RE: Application for Significant Revision
NSR Permit No. 1092-M8R2
Jal No. 3 Gas Plant
Lea County, New Mexico
ETC Texas Pipeline, Ltd.

Dear Sir/Madam:

On behalf of ETC Texas Pipeline, Ltd. (ETC), Altamira-US, LLC (Altamira) is submitting the enclosed Application for a Significant Revision to NSR Permit No. 1092-M8R3 for the Jal No. 3 Gas Plant (Facility). The Facility is located approximately 4 miles north-northeast of Jal in Lea County, New Mexico.

With this application, ETC plans to remove ten (10) natural gas compressor engines, two (2) heaters, two (2) boilers, one (1) glycol dehydrator, one (1) thermal oxidizer, and supporting equipment. Two (2) Caterpillar 3606 engines, one (1) 28 MMBtu/hr amine system heater, one (1) glycol dehydration unit with associated reboiler and thermal oxidizer, one (1) AGI compressor, and (1) 10 MMBtu/hr condensate stabilizer heater will be added.

The enclosed application has been prepared in accordance with the requirements set forth in Title 20 New Mexico Administrative Code, Section 2.72.219. (NMAC 20.2.72.219.D.1.a.).

ETC has a payment credit of $4550 for GCP-OG application submitted to NMED March 2022, that NMED requested be withdrawn and replaced with this NSR application. ETC understands this monies will be applied to NSR Permit fee of $500 for this app and balance due after state finishes reviewing the application.

If you have any questions or comments, please contact Carolyn Blackaller of ETC at (432) 203-8920 or carolyn.blackaller@energytransfer.com.

Sincerely,
Altamira-US, LLC

Laura Worthen Lodes
VP-Mid Continent Operations

cc: Carolyn Blackaller, ETC
Chris Hansen, ETC

APPLICATION FOR SIGNIFICANT REVISION
NSR PERMIT NO. 1092-M8R2
JAL #3 GAS PLANT
LEA COUNTY, NM

JUNE 2022

Submitted to:
New Mexico Environment Department
Air Quality Bureau, Permits Section
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

Prepared for:
ETC Texas Pipeline, Ltd.
600 N. Marienfeld St., Suite 700
Midland, TX 79701
214-840-5650

Prepared by:
Altamira-US, LLC
525 Central Park Dr., Suite 500
Oklahoma City, Oklahoma 73105
405-702-1618

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Table 2-A: Regulated Emission Sources

Unit and stack numbering must correspond throughout the application package. If applying for a NOI under 20.2.73 NMAC, equipment exemptions under 2.72.202 NMAC do not apply.

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufacturer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] / Date of Construction/ Reconstruction[2]	Controlled by Unit # / Emissions vented to Stack #	Source Classification Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
S1	Natural Gas Compressor Engine	Superior	2416G	333489	3200 hp	3201 hp	1996 2004	S1 S1	31000203	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	
S2	Natural Gas Compressor Engine	Superior	2416G	333519	3200 hp	3201 hp	1996 2008	S2 S2	31000203	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	
S3	Natural Gas Compressor Engine	Superior	2416G	333529	3200 hp	3201 hp	1997 2004	S3 S3	31000203	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	
S4	Natural Gas Compressor Engine	Superior	2416G	334729	3200 hp	3201 hp	1997 2004	S4 S4	31000203	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	
S5	Natural Gas Compressor Engine	Superior	12 SGTA	2932559	2000 hp	2000 hp	1983 2004	S5 S5	31000203	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	
C1	Natural Gas Compressor Engine	Caterpillar	G3612	1YG00065	3550 hp	3550 hp	8/7/2018 2019	C1 C1	31000203	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	
C2	Natural Gas Compressor Engine	Caterpillar	G3612	BKE00660	3550 hp	3550 hp	1/2/2008 2016	C2 C2	31000203	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	
C3	Natural Gas Compressor Engine	Caterpillar	G3612	BKE00662	3550 hp	3550 hp	1/2/2008 2016	C3 C3	31000203	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	
C4	Natural Gas Compressor Engine	Caterpillar	G3612	BKE00659	3550 hp	3550 hp	1/2/2008 2016	C4 C4	31000203	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	
C5	Natural Gas Compressor Engine	Caterpillar	G3606	TBD	1875 hp	1875 hp	Post 7/1/2010 TBD	C5 C5	31000203	☐ Existing (unchanged) ☐ To be Removed ☒ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	
C6	Natural Gas Compressor Engine	Caterpillar	G3606	TBD	1875 hp	1875 hp	Post 7/1/2010 TBD	C6 C6	31000203	☐ Existing (unchanged) ☐ To be Removed ☒ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	
1A	Natural Gas Compressor Engine	Cooper-Bessemer	GMV-10TF LE	42109	1100 hp	1100 hp	9/1/1948 1948	N/A 1	31000203	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	2SLB	
2A	Natural Gas Compressor Engine	Cooper-Bessemer	GMV-10TF LE	42110	1100 hp	1100 hp	9/1/1948 1948	N/A 2	31000203	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	2SLB	
3A	Natural Gas Compressor Engine	Cooper-Bessemer	GMV-10TF LE	42107	1100 hp	1100 hp	9/1/1948 1948	N/A 3	31000203	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	2SLB	
4A	Natural Gas Compressor Engine	Cooper-Bessemer	GMV-10TF LE	42108	1100 hp	1100 hp	9/1/1948 1948	N/A 4	31000203	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	2SLB	

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufacturer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] / Date of Construction/ Reconstruction[2]	Controlled by Unit # / Emissions vented to Stack #	Source Classification Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
5A	Natural Gas Compressor Engine	Cooper-Bessemer	GMV-10TF LE	42106	1100 hp	1100 hp	9/1/1948 1948	N/A 5	31000203	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	2SLB	
7H	Gas Heater	Entec	N/A	76152	2.5 MMbtu/hr	2.5 MMbtu/hr	Unknown Unknown	N/A 7H	31000404	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
11H	Gas Heater	Eclipse	N/A	47973	3.5 MMbtu/hr	3.5 MMbtu/hr	Unknown Unknown	N/A 11H	31000404	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
12H	Regeneration Gas Heater	TBD	N/A	TBD	28 MMbtu/hr	28 MMbtu/hr	 TBD	N/A 12H	31000404	☐ Existing (unchanged) ☐ To be Removed ☒ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
13H	Dehy Reboiler	TBD	N/A	TBD	2.0 MMbtu/hr	2.0 MMbtu/hr	 TBD	 13H	31000404	☐ Existing (unchanged) ☐ To be Removed ☒ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
14H	Stabilizer Heater	TBD	N/A	TBD	10 MMbtu/hr	10 MMbtu/hr	 TBD	 14H	31000404	☐ Existing (unchanged) ☐ To be Removed ☒ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
9S	Thermal Oxidizer	Entec	N/A	N/A	8 MMbtu/hr	8 MMbtu/hr	Unknown 1993	N/A 9S	31000209	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
31B	Boiler	Nebraska	MS-E-59	D-3792	90.9 MMbtu/hr	90.9 MMbtu/hr	1998 12/12/2011	N/A 31B	3100414	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
32B	Boiler	Victory Energy VS-5-71	VS-5-71	12017	120.9 MMBtu/hr	120.9 MMBtu/hr	7/15/2013 TBD	N/A 32B	31000414	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
8F	Gas Plant Flare	John Zink	N/A	N/A	10 MMcf/d	10 MMcf/d	Unknown 1971	N/A 8F	31000215	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
9F	Treatment Flare	John Zink	N/A	N/A	2.9 MMcf/d	2.9 MMcf/d	Unknown 1993	N/A 9F	31000215	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
10F	Inlet Flare	John Zink	N/A	N/A	75 MMcf/d	75 MMcf/d	Unknown 1950	N/A 10F	31000215	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
TK-3	Scrubber Liquids Tank	N/A	N/A	N/A	8,820 gal	8,820 gal	Unknown 1970	N/A N/A	40400301	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
TK-4	Scrubber Liquids Tank	N/A	N/A	N/A	8,820 gal	8,820 gal	Unknown 1970	N/A N/A	40400301	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
TK-46	Scrubber Liquids Tank	N/A	N/A	N/A	4,512 gal	4,512 gal	Unknown 1970	N/A N/A	40400301	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
FUG1	Fugitive Emissions	N/A	N/A	N/A	N/A	N/A	N/A N/A	8F-10F 8F-10F	31088811	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufacturer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] / Date of Construction/ Reconstruction[2]	Controlled by Unit # / Emissions vented to Stack #	Source Classification Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
FUG2	Fugitive Emissions	N/A	N/A	N/A	N/A	N/A	N/A N/A	9F 9F	31088811	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
DR1	Dehydrator Regenerator (with condenser)	Unknown	N/A	N/A	150 MMscfd	150 MMscfd	Unknown 1959 (Regen)	9F 9F	31000301	☐ Existing (unchanged) ☒ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
DR2	Dehydrator Regenerator (with condenser)	TBD	N/A	TBD	70 MMscfd	70 MMscfd	TBD TBD	9F 9F	31000301	☐ Existing (unchanged) ☐ To be Removed ☒ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
LOADOUT	Condensate Truck Loadout	N/A	N/A	N/A	800 bbl/day	800 bbl/day	Unknown Unknown	N/A N/A	40400301	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
SSM/M	Startup, Shutdown, Maintenance/ Malfunction	N/A	N/A	N/A	N/A	N/A	N/A N/A	8F, 10F 8F, 10F	31088811	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
SSM-Inlet (Flare 10F)	Routine Inlet Blow Downs	N/A	N/A	N/A	N/A	N/A	N/A N/A	10F 10F	31088811	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
TK-519	Gunbarrel	N/A	N/A	N/A	600 bbl	600 bbl	N/A 2015	VRU N/A	40400311	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
TK-519C	Scrubber Oil Tank	N/A	N/A	N/A	500 bbl	500 bbl	N/A 2015	N/A N/A	40400311	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
TK-519A	Water Tank	N/A	N/A	N/A	500 bbl	500 bbl	N/A 2015	N/A N/A	40400315	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
LOAD	Scrubber Oil Loading	N/A	N/A	N/A	500 bbl	500 bbl	N/A 2015	N/A N/A	31088811	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		

[3] To properly account for power conversion efficiencies, generator set rated capacity shall be reported as the rated capacity of the engine in horsepower, not the kilowatt capacity of the generator set.

[4] "4SLB" means four stroke lean burn engine, "4SRB" means four stroke rich burn engine, "2SLB" means two stroke lean burn engine, "CI" means compression ignition, and "SI" means spark ignition

Section 3

Application Summary

The **Application Summary** shall include a brief description of the facility and its process, the type of permit application, the applicable regulation (i.e. 20.2.72.200.A.X, or 20.2.73 NMAC) under which the application is being submitted, and any air quality permit numbers associated with this site. If this facility is to be collocated with another facility, provide details of the other facility including permit number(s). In case of a revision or modification to a facility, provide the lowest level regulatory citation (i.e. 20.2.72.219.B.1.d NMAC) under which the revision or modification is being requested. Also describe the proposed changes from the original permit, how the proposed modification will affect the facility's operations and emissions, de-bottlenecking impacts, and changes to the facility's major/minor status (both PSD & Title V).

The **Process Summary** shall include a brief description of the facility and its processes.

Startup, Shutdown, and Maintenance (SSM) routine or predictable emissions: Provide an overview of how SSM emissions are accounted for in this application. Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (http://www.env.nm.gov/aqb/permit/app_form.html) for more detailed instructions on SSM emissions.

The ETC Texas Pipeline Ltd (ETC) Jal #3 Gas Plant (Jal 3) is a natural gas processing plant located near Jal, NM in Lea County. Lea County is attainment or non-classifiable for all criteria air pollutants. Jal 3 is currently a major source for the Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs and is a major source of hazardous air pollutants (HAPs). ETC is submitting this application to apply for a Significant Revision (pursuant to NMAC 20.2.72.219.d.1.a) to its current Air Quality NSR Permit 1092-M8R2. As a result of this permit action, Jal 3 will no longer be a major source under the PSD program or a major source of HAPs.

With this application, ETC plans to remove ten (10) natural gas compressor engines, two (2) heaters, two (2) boilers, one (1) glycol dehydrator, one (1) thermal oxidizer, and supporting equipment. Two (2) Caterpillar 3606 engines, one (1) 28 MMBtu/hr amine system heater, one (1) glycol dehydration unit with associated reboiler and thermal oxidizer, one (1) AGI compressor, and (1) 10 MMBtu/hr condensate stabilizer heater will be added. The compressors and associated fugitive equipment components will be subject to NSPS OOOOa.

Remainder of Application Omitted for Brevity

AIR QUALITY BUREAU
NEW SOURCE REVIEW PERMIT
Issued under 20.2.72 NMAC

Certified Mail No: 7015 1520 0001 8091 1278
Return Receipt Requested

NSR Permit No:	1092-M10
Facility Name:	Jal #3 Gas Plant
Permittee Name:	ETC Texas Pipeline LTD
Mailing Address:	8111 Westchester Drive Suite 600 Dallas, TX 75225
TEMPO/IDEA ID No:	569 - PRN20220002
AIRS No:	35-025-0008
Permitting Action:	Significant Permit Revision
Source Classification:	Title V Major, PSD Minor
Facility Location:	672,129 m E by 3,561,167 m N; Zone 13; Datum WGS84
County:	Lea County
Air Quality Bureau Contact:	Joseph Kimbrell
Main AQB Phone No.	(505) 476-4300

Donna Intermont Digitally signed by Donna Intermont Date: 2022.11.07 11:23:09 -07'00' for EBK

Liz Bisbey-Kuehn
Bureau Chief
Air Quality Bureau

November 7, 2022
Date

Template version: 06/30/2021

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PART A FACILITY SPECIFIC REQUIREMENTS

A100 Introduction

A. This permit, NSR 1092-M10, supersedes all portions of Air Quality Permit 1092-M8, issued August 01, 2013 and revision M8R1 thru M8R7, except portions requiring compliance tests. Compliance test conditions from previous permits, if not completed, are still in effect, in addition to compliance test requirements contained in this permit.

A101 Permit Duration (expiration)

A. The term of this permit is permanent unless withdrawn or cancelled by the Department.

A102 Facility: Description

A. The function of the facility is to treat and process natural gas. The facility consists of natural gas compression units, amine-sweetening units, an acid gas reinjection system, various storage tanks, fugitive emissions, and three flares.

B. This facility is located approximately 4 miles north northeast of Jal, New Mexico in Lea County.

C. This modification consists of removing ten (10) natural gas compressor engines, two (2) heaters, two (2) boilers, one (1) glycol dehydrator, one (1) thermal oxidizer, and supporting equipment and adding two (2) Caterpillar 3606 engines, one (1) 28 MMBtu/hr amine system heater (Unit Amine-2 is replacing Amine-1), one (1) glycol dehydration unit with associated reboiler and thermal oxidizer, one (1) AGI compressor, and (1) 10 MMBtu/hr condensate stabilizer heater. Also, added applicability to 20.2.50 NMAC, Oil and Gas Sector – Ozone Precursor Pollutants. The description of this modification is for informational purposes only and is not enforceable.

D. Tables 102.A and Table 102.B show the total potential emission rates (PER) from this facility for information only. This is not an enforceable condition and excludes emissions from Minor NSR exempt activities per 20.2.72.202 NMAC.

Table 102.A: Total Potential Emission Rate (PER) from Entire Facility

Pollutant	Emissions (tons per year)
Nitrogen Oxides (NOx)	105.5
Carbon Monoxide (CO)	88.2
Volatile Organic Compounds (VOC) [1]	163.6
Sulfur Dioxide (SO_2)	60.6

Table 104.A: Regulated Sources List

Unit No.	Source Description	Make/ Model	Serial No.	Construction/ Reconstruction Date	Manufacture Date	Manufacturer Rated Capacity /Permitted Capacity
Amine-2	Amine Unit	TBD	TBD	2022	TBD	100 MMSCFD
C1	4SLB RICE	Caterpillar G3612	BKE00658	4/1/2019	8/2013	3550 HP
C2	4SLB RICE	Caterpillar G3612	BKE00660	7/1/2017	8/2013	3550 HP
C3	4SLB RICE	Caterpillar G3612	BKE00662	7/1/2017	8/2013	3550 HP
C4	4SLB RICE	Caterpillar G3612	BKE00659	7/1/2017	8/2013	3550 HP
C5	4SLB RICE	Caterpillar G3606	TBD	TBD	TBD	1875 HP
C6	4SLB RICE	Caterpillar G3606	TBD	TBD	TBD	1875 HP
COMP-1 thru COMP-6	Compressor seals for Units C1-C6	N/A	N/A	N/A	N/A	N/A
8F	Gas Plant Flare	John Zink	N/A	1971	Not reported	10 MMscfd
9F	Treatment Flare	John Zink	N/A	1993	Not reported	2.9 MMscfd
10F	Inlet Flare	John Zink	N/A	1950	Not reported	75 MMscfd
12H	Regeneration Gas Heater	TBD	TBD	TBD	TBD	28 MMBtu/hr
13H	Dehy Reboiler	TBD	TBD	TBD	TBD	2.0 MMBtu/hr
14H	Stabilizer Heater	TBD	TBD	TBD	TBD	10 MMBtu/hr
DR2	Dehydrator Regenerator (with condenser)	TBD	TBD	TBD	TBD	70 MMscfd
TK 3	Scrubber Liquids Tank (hydrocarbon liquids)	N/A	N/A	1970	Not reported	8,820 gal
TK 4	Scrubber Liquids Tank (hydrocarbon liquids)	N/A	N/A	1970	Not reported	8,820 gal
TK 46	Scrubber Liquids Tank (mixed hydrocarbon liquids)	N/A	N/A	1970	Not reported	4,512 gal
TK-519	Gunbarrel	TBD	TBD	TBD	2015	600 bbl
TK-519C	Scrubber Oil Tank	TBD	TBD	TBD	2015	500 bbl
TK-519A	Water Tank	TBD	TBD	TBD	2015	500 bbl
VRU	Vapor Recovery Unit	TBD	TBD	TBD	2015	500 bbl

Table 104.A: Regulated Sources List

Unit No.	Source Description	Make/ Model	Serial No.	Construction/ Reconstruction Date	Manufacture Date	Manufacturer Rated Capacity /Permitted Capacity
LOAD	Scrubber Oil Loading	TBD	TBD	TBD	2015	48 bbl/day
FUG1	Fugitive Emissions (valves, fittings, flanges, seals, etc associated with KKK, OOOO, & non-regulated sources)	N/A	N/A	N/A	N/A	N/A
FUG2	Fugitive Emissions (valves, fittings, flanges, seals, etc associated with HH sources)	N/A	N/A	N/A	N/A	N/A
Loadout	Tank Loading – Condensate Loadout Units TK-50-TK-52	N/A	N/A	TBD	Not reported	9.198 million gal/yr; 800 bbl/d
9F	Flare Unit 9 SSM	N/A	N/A	N/A	N/A	N/A
10F	Flare Unit 10F SSM	N/A	N/A	N/A	N/A	N/A
C1-C6 SSM	C1-C4 SSM	N/A	N/A	N/A	N/A	N/A
Malfunc-tions	Malfunctions	N/A	N/A	N/A	N/A	N/A

1. All TBD (to be determined) units and like-kind engine replacements must be evaluated for applicability to NSPS and MACT requirements.

A105 Facility: Control Equipment

A. Table 105 lists all the pollution control equipment required for this facility. Each emission point is identified by the same number that was assigned to it in the permit application.

Table 105.A: Control Equipment List:

Control Equipment Unit No.	Control Description	Pollutant being controlled	Control for Unit No.[1]
C1-C6	Oxidation Catalyst	CO, VOC, HCHO	C1-C4

Remainder of Permit Omitted for Brevity

D.6 Transwestern Pipeline Company

Supporting documentation for Transwestern Pipeline Company is provided below. Facility-specific documentation is provided first, followed by documentation pertaining to multiple facilities and/or the owner/operator. The following documents are included in this section (in reading order):

- Mountainair Compressor Station No. 7:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (10/30/2019)
    - Follow-Up Submittal (1/23/2020)
- Roswell Compressor Station No. 9:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (10/30/2019)
    - Follow-Up Submittal (1/23/2020)
- Multiple Facilities and/or Owner/Operator:
    - Follow-Up Submittal (9/10/2020)
    - Follow-Up Submittal (3/25/2021)
    - Follow-Up Submittal (8/11/2023)

NMED Final Cost Evaluation
Transwestern Pipeline Company - Mountainair Compressor Station No. 7

Facility Information

TWP - Mountainair Compressor Station No. 7	**Facility**
Three 4SLB 4,500-hp RICE	**Units**
701, 702, and 703	**Unit IDs**
LEC	**Evaluated Pollution Control**
2.5	**Post-control Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
4500	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 701	Unit 702	Unit 703	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	Detailed cost estimate includes all equipment, controls upgrade, labor, engineering, installation, contingency, comissioning and post commissioning support. Estimate is "based on a current quote from Cooper for the LEC upgrades, and previous project estimates prepared for the gearbox replacement (adjusted for inflation to current dollars)."
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	-	
Additional Capital ($)	AC	$ -	$ -	$ -	-	
Total Capital Investment ($)	TCI	$ 5,452,333	$ 5,452,333	$ 5,452,333	TWP 8.11.23 update	
Interest Rate (%)	R	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	TWP used prime rate as of 7.11.23 (8%) in its 8.11.23 update
Useful Life (yr)	Y	20	20	20	TWP 8.11.23 update	Consistent with other FFAs and EPA default
Capital Recovery Factor	CRF	0.0981	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 534,831	$ 534,831	$ 534,831	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	$ -	-	Incremental O&M of a LEC retrofit is expected to be negligible
Other Indirect Annual Costs ($/yr)	OAC	$ 218,093	$ 218,093	$ 218,093	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 752,925	$ 752,925	$ 752,925	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	76%	79%	77%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	374.7	460.7	428.2	CY 2022 emissions testing and average operating hours (2019-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by TWP
Projected Actual Emissions (ton/yr)	PAE	374.7	460.7	428.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	284.0	362.8	330.2	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 2,651**	**$ 2,075**	**$ 2,280**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 2,651**	**$ 2,075**	**$ 2,280**	-	CE1 x PI

NMED Final Cost Evaluation
Transwestern Pipeline Company - Mountainair Compressor Station No. 7

Facility Information

TWP - Mountainair Compressor Station No. 7	**Facility**
Two 4SRB 335-hp RICE	**Units**
721 and 722	**Unit IDs**
LEC	**Evaluated Pollution Control**
2.5	**Post-control Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
335	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Units 721 & 722	Unit 721	Unit 722	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 811,792	$ 405,896	$ 405,896	TWP 8.11.23 update	TWP estimate for Unit 701/702/703 LEC, scaled by hp rating
Interest Rate (%)	R	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	TWP used prime rate as of 7.11.23 (8%) in its 8.11.23 update
Useful Life (yr)	Y	20	20	20	TWP 8.11.23 update	Consistent with other FFAs and EPA default
Capital Recovery Factor	CRF	0.0981	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 79,630	$ 39,815	$ 39,815	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	$ -	-	Incremental O&M of a LEC retrofit is expected to be negligible
Other Indirect Annual Costs ($/yr)	OAC	$ 32,472	$ 16,236	$ 16,236	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 112,102	$ 56,051	$ 56,051	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	88%	92%	71%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	66.0	52.1	13.9	CY 2022 emissions testing and average operating hours (2019-2021)	Used the average of the two units NOx lb/hr and a total of 8760 hours to calculate 'Units 721 & 722' BAE. Used each unit's NOx lb/hr and 8760/2 hours to calculate each individual unit's BAE.
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by TWP
Projected Actual Emissions (ton/yr)	PAE	66.0	52.1	13.9	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	57.9	48.1	9.8	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 1,936**	**$ 1,166**	**$ 5,696**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 1,936**	**$ 1,166**	**$ 5,696**	-	CE1 x PI

NMED Final Cost Evaluation
Transwestern Pipeline Company - Mountainair Compressor Station No. 7

Facility Information

TWP - Mountainair Compressor Station No. 7	**Facility**
Three 4SLB 4,500-hp RICE	**Units**
701, 702, and 703	**Unit IDs**
SCR	**Evaluated Pollution Control**
80%	**SCR Control efficiency**
38.17	**Heat Input Capacity (MMBtu/hr/unit; assumes 30% efficiency)**

Supporting Information

2024	**Calendar year associated with cost estimates**
4500	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 701	Unit 702	Unit 703	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 2,676,009	$ 2,675,509	$ 2,527,744	EPA SCR Tool (2024$)	
Interest Rate (%)	R	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	TWP used prime rate as of 7.11.23 (8%) in its 8.11.23 update
Useful Life (yr)	Y	20	20	20	EPA Cost Manual	
Capital Recovery Factor	CRF	0.0981	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 262,496	$ 262,447	$ 247,952	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 91,970	$ 106,687	$ 99,127	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 2,789	$ 2,789	$ 2,780	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 357,254	$ 371,922	$ 349,859	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	80%	80%	80%	Initial TWP FFA Submittal	Consistent with EPA and industry documentation
Baseline Actual NOx Emissions (ton/yr)	BAE	374.7	460.7	428.2	CY 2022 emissions testing and average operating hours (2019-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by TWP
Projected Actual Emissions (ton/yr)	PAE	374.7	460.7	428.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	299.7	368.5	342.5	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 1,192**	**$ 1,009**	**$ 1,021**	-	TAC/ER

NMED Final Cost Evaluation
Transwestern Pipeline Company - Mountainair Compressor Station No. 7

Facility Information

TWP - Mountainair Compressor Station No. 7	**Facility**
Three 4SLB 4,500-hp RICE	**Units**
701, 702, and 703 (and 721 and 722)	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
44.7	**Post-control Emissions (ton/yr, provided by facility)**

Supporting Information

2023	**Calendar year associated with cost estimates**
4500	**Maximum Power Output Unit (hp/unit)**

Economic Evaluation

Cost Component		All Units	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	TWP 8.11.23 update explained that replacing 701, 702, and 703 with new CTs would require the replacement of 721 and 722 with microturbines to improve power reliability. TCI of the new CTs is $46.25M according to TWP. TWP did not include TCI of microturbines in its 8.11.23 update. TCI for the microturbines has been included as "Additional Capital" and estimated using Table 5-3 of the EPA CHP Catalog of Technologies - Microturbines, and CEPCI. This initial TCI (2023$) is over-estimated given that CHP installations are more complex and costly than their power generation only equivalents.
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ 46,250,000	TWP 8.11.23 update	
Additional Capital ($)	AC	$ 2,471,898	TCI of 2x ~335 hp microturbines	
Total Capital Investment ($)	TCI	$ 48,721,898	TWP 8.11.23 update & ERG estimate	
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	TWP used prime rate as of 7.11.23 (8%) in its 8.11.23 update
Useful Life (yr)	Y	30	ERG experience based on discussions with CT manufacturers	TWP indicated 25 years
Capital Recovery Factor	CRF	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 4,125,343	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ (740,478)	Net change in O&M costs	OM1 - OM2 + OM3
New turbine O&M ($/yr)	OM1	$ 280,280	TWP 8.11.23 update	Based on TWP similar facility costs (2022$). Adjusted to 2023$ using CEPCI index of 0.98 (CEPCI 2023 (797.9)/ CEPCI 2022 (816.0))
Existing RICE O&M ($/yr)	OM2	$ 1,020,758	TWP 8.11.23 update	Estimated O&M for 721 and 722 using 701 O&M costs and adjusted using hp ratio
New microturbine O&M ($/yr)	OM3	$ -	-	Not specified by TWP
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 3,384,865	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	97%	-	ER/PAE
Baseline Actual NOx Emissions (ton/yr)	BAET	1,329.5	-	BAE1 + BAE2
	BAE1	1,263.5	CY 2022 emissions testing and average operating hours (2019-2021)	BAE of Units 701, 702 and 703
	BAE2	66.0	Average emission rate and 8760 hr/yr for 1 unit	BAE of Units 721 and 722
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by TWP
Projected Actual Emissions (ton/yr)	PAE	1329.5	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	1284.5	-	PAE - CTE - MTE
	CTE	44.74	TWP 8.11.23 update	Post control estimated emissions (of new CT)
	MTE	0.26	Calculated	Microturbine emissions: 0.39 lb/MWh, assumed 60% load, 8760 hr/yr for 1 unit (other is backup)
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 2,635**	-	TAC/ER
Price Index	PI	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 2,635**	-	CE1 x PI

NMED Final Cost Evaluation
Transwestern Pipeline Company - Mountainair Compressor Station No. 7

Facility Information	
TWP - Mountainair Compressor Station No. 7	**Facility**
Three 4SLB 4,500-hp RICE	**Units**
701, 702, and 703	**Unit IDs**
Replacement with EMD	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (g NOx/bhp-hr)**

Supporting Information	
2023	**Calendar year associated with cost estimates**
4500	**Maximum Power Output (hp/unit)**
3	**Number of units (assumed) that will be replaced with EMD**

Economic Evaluation

Cost Component		**All Units**	**Source**	**Methodology/Note**
Purchased equipment costs ($)	PEC	$ -	-	Included in TCC
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	Included in TCC
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	Included in TCC
Indirect Capital Costs ($)	IDC	$ -	-	Included in TCC
Total Capital Costs - Direct ($)	TCC	$ 36,000,000	TWP 8.11.23 update	TWP states that the project costs estimate is based on were carried forward and adjusted for inflation into current dollars
Additional Capital ($)	AC	$ 21,409,200	Estimated	At least 8 miles of lines @ $750k/mile. New substation cost estimated using $20M Harvest estimate and adjusted using power rating (13500 vs. 17522 hp)
Total Capital Investment ($)	TCI	$ 57,409,200	-	TCC + AC
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	TWP used prime rate as of 7.11.23 (8%) in its 8.11.23 update
Useful Life (yr)	Y	25	TWP 8.11.23 update	
Capital Recovery Factor	CRF	0.0897	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 5,150,218	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 4,190,946	-	OC + AOM + AFC
Other ($/yr)	OC	$ 6,306,800	TWP 8.11.23 update	
Associated non-electricity O&M ($/yr)	AOM			
Annual Fuel Credit ($/yr)	AFC	$ (2,115,854)	3/25/21 email from TWP	Scaled to account for projected operation and converted to 2023$ using CEPCI
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 9,341,163	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	1,329.5	CY 2022 emissions testing and average operating hours (2019-2021)	Sum of BAE of units 701, 702, 703, 721 and 722
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by TWP
Projected Actual Emissions (ton/yr)	PAE	1329.5	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	1329.5	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 7,026**	-	TAC/ER
Price Index	PI	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 7,026**	-	CE1 x PI

NMED Final Cost Evaluation
Transwestern Pipeline Company - Mountainair Compressor Station No. 7

Unit 701: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	34.78	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	246,631,018	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	6870	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	2.947	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.5894	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			
*The SRF value of 1.05 is a default value. User should enter actual value, if known.				
Number of SCR reactor chambers (n_{scr})			1	
Number of catalyst layers (R_{layer})			3	
Number of empty catalyst layers (R_{empty})			1	
Ammonia Slip (Slip) provided by vendor			2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)			UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)			UNK	acfm
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours		
Estimated SCR equipment life	20	Years*		
* For industrial boilers, the typical equipment life is between 20 and 25 years.				
Gas temperature at the SCR inlet (T)			650	°F
*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.				
Base case fuel gas volumetric flow rate factor (Q_{fuel})			UNK	ft^3/min-MMBtu/hour
Concentration of reagent as stored (C_{stored})	29	percent*		
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*		
Number of days reagent is stored ($t_{storage}$)	14	days		

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 701: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	35	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	295,511,930	scf/Year
Actual Annual fuel consumption (Mactual) =		246,631,018	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.835	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7311	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	81.99	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	299.72	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.29	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.4	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	257.28	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	32	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	110	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	15	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	5,000	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	20.59	kW

Unit 701: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,676,009	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$91,970 in 2024 dollars
Indirect Annual Costs (IDAC) =	$265,305 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$357,275 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$13,380 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$56,768 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$15,053 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$6,768 in 2024 dollars
Direct Annual Cost =		$91,970 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,789 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$262,517 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$265,305 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$357,275 per year in 2024 dollars
NOx Removed =	300 tons/year
Cost Effectiveness =	$1,192 per ton of NOx removed in 2024 dollars

NMED Final Cost Evaluation
Transwestern Pipeline Company - Mountainair Compressor Station No. 7

Unit 702: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	34.77	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	266,086,615	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	6870	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	3.359	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.6717	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 702: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	35	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	295,426,964	scf/Year	
Actual Annual fuel consumption (Mactual) =		266,086,615	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.901	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7890	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	93.42	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	368.56	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.29		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.4	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	276.11	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	36	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	125	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	17	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	5,700	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	20.58	kW

Unit 702: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,675,509	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$106,687 in 2024 dollars
Indirect Annual Costs (IDAC) =	$265,256 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$371,943 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$13,378 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$69,805 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$16,241 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$7,264 in 2024 dollars
Direct Annual Cost =		$106,687 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,789 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$262,467 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$265,256 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$371,943 per year in 2024 dollars
NOx Removed =	369 tons/year
Cost Effectiveness =	$1,009 per ton of NOx removed in 2024 dollars

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Unit 703: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	31.86	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	244,218,797	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	6870	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	3.401	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.6802	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 703: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	32	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	270,701,843	scf/Year	
Actual Annual fuel consumption (Mactual) =		244,218,797	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.902	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7903	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	86.69	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	342.55	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.29		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.4	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	254.79	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	34	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	116	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	16	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	5,300	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	18.86	kW

Unit 703: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,527,744	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$99,127 in 2024 dollars
Indirect Annual Costs (IDAC) =	$250,751 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$349,878 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,639 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$64,879 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$14,906 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$6,703 in 2024 dollars
Direct Annual Cost =		$99,127 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,780 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$247,972 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$250,751 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$349,878 per year in 2024 dollars
NOx Removed =	343 tons/year
Cost Effectiveness =	$1,021 per ton of NOx removed in 2024 dollars

October 30, 2019 Reference No. 11203587

Mark Jones
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505

Dear Mr. Jones:

Re: Four Factor Analysis
Mountainair Compressor Station
Transwestern Pipeline Company, LLC

GHD Services, Inc. (GHD) is submitting, on behalf of Transwestern Pipeline Company, LLC., a four-factor analysis of the Mountainair Compressor Station to the New Mexico Environment Department (NMED). This report is for the NMED Regional Haze Second Planning Period Progress Analysis under the Clean Air Act (CAA) and Regional Haze Rule (40 CFR §51.300 to 51.309).

If you have any questions or concerns, please contact myself at (720) 974-0937 or Larry Campbell at (575) 625-8022.

Sincerely,

GHD

Sergio Guerra
Project Manager

SG/PH/1

Encl. Four-Factor Analysis

cc: Larry Campbell – Transwestern Pipeline Company, LLC.

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REGISTERED COMPANY FOR ISO 9001 ENGINEERING DESIGN



Four-Factor Analysis for Regional Haze Planning in New Mexico

Mountainair Compressor Station No. 7
Torrance County, New Mexico
Title V Operating Permit No. P153-R3M1
AIRS No. 35-057-0001

Transwestern Pipeline Company, LLC









14998 West 6th Avenue Suite 800 80401 Golden Colorado USA | 11203587 | October 2019

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Appendix Index

Appendix A RICE Engine Baseline Emissions, Reductions, and Control Cost Analysis

List of Acronyms

AFGD ..... Advanced Flue Gas Desulfurization
APCD ..... Air Pollution Control Division
BART ..... Best Available Retrofit Technology
CAA ..... Clean Air Act
CAIR ..... Clean Air Interstate Rule
CaSO3 ..... Calcium sulfite
CaSO4 ..... Calcium sulfate
CO ..... Carbon Monoxide
CO2 ..... Carbon Dioxide
CPI ..... Consumer Price Index
DEP ..... Department of Environmental Protection
DEQ ..... Department of Environmental Quality
DNR ..... Department of Natural Resources
DSI ..... Dry Sorbent Injection
EIA ..... Energy Information Administration
EPA ..... Environmental Protection Agency
FGD ..... Flue Gas Desulfurization
FGR ..... Flue Gas Recirculation
ICI ..... Industrial, Commercial, Institutional
HEIS ..... High Energy Ignition Systems
LADCO ..... Lake Michigan Air Directors Consortium
LNB ..... Low NOx Burners
MACT ..... Most Achievable Control Technology
MARAMA ..... Mid-Atlantic Regional Air Management Association
N2 ..... Nitrogen gas
NCASI ..... National Council for Air and Stream Improvement
NESCAUM ..... Northeast States for Coordinated Air Use Management
NESHAP ..... National Emission Standards for Hazardous Air Pollutants
NH3 ..... Ammonia
NOx ..... Nitrogen Oxides
NSCR ..... Non-Selective Catalytic Reduction
NSPS ..... New Source Performance Standards
OFA ..... Over-Fired Air
PM ..... Particulate Matter
RICE ..... Reciprocating Internal Combustion Engine
RSCR ..... Regenerative Selective Catalytic Reduction
SCR ..... Selective Catalytic Reduction
SD ..... Spray Dry
SIP ..... State Implementation Plan
SNCR ..... Selective Non-Catalytic Reduction
SO2 ..... Sulfur Dioxide
SSM ..... Startup, Shutdown, Maintenance
ULNB ..... Ultra Low NOx Burners
WRAP ..... Western Regional Air Partnership
VOC ..... Volatile Organic Compound

1. Executive Summary

In response to the New Mexico Environment Department (NMED) letter dated July 18, 2019, GHD Services, Inc. (GHD) was retained by ETC Texas Pipeline, LTD, the parent company of Transwestern Pipeline Company, LLC, to prepare a four-factor analysis for the NMED Regional Haze Second Planning Period Progress Analysis under the Clean Air Act (CAA) and Regional Haze Rule (40 CFR §51.300 to 51.309). As a part of this Progress Analysis, NO_x and SO_2 emissions were evaluated at the Mountainair Compressor Station (Mountainair CS).

The four-factor analysis is codified in 40 CFR §51.308(d)(1)(i)(A) and is designated as a means for establishing reasonable progress goals towards achieving natural visibility conditions. The four factors to consider are:

1. The costs of compliance
2. The time necessary for compliance
3. The energy and non-air quality environmental impacts of compliance
4. The remaining useful life of any potentially affected sources

The purpose of the four-factor analysis is to identify control measures for reducing emissions that could be used to establish the long-term strategy for attaining the states visibility goals. The NMED has requested that evaluations be completed for individual equipment that have a potential to emit (PTE) greater than ten pounds per hour of NO_x or SO_2. The source categories identified at Mountainair CS for evaluation are three existing compressor engines (Units 701, 702, and 703). NMED also instructed to use actual emissions from reporting year 2016 as baseline emissions to calculate emission reductions for control options evaluated. The cost range for emission reductions reflects the range of operation time in 2016 between the two RICE compressor engines analyzed. The results of the subsequent four-factor analysis are in Table 1.1 below.

Table 1.1 Summary of Mountainair CS Four Factor Analysis Results

Source Category	Regional Haze Pollutant Analyzed	Average Cost in 2019 Dollars (dollars per ton of pollutant reduction)	Compliance Timeframe	Energy & Non-Air Quality Impacts	Remaining Useful Life
RICE Engines (Units 701, 702, and 703)	NO_x; Low Emission Controls (LEC)	$2,000 - $13,000	2-5 Years	None known for LEC	25 years for controls; Indefinite for RICE engines
	NO_x; Selective Catalytic Reduction (SCR)	$1,400 - $7,000	2-5 Years	Storage and handling of hazardous materials	25 years for controls; Indefinite for RICE engines

2. Source Category Analysis for RICE Engines

2.1 Source Category Description

Mountainair CS operates three (3) Reciprocating Internal Combustion Engines (RICE) that are subject to the requirements of the four-factor analysis. Mountainair CS's compression engines are 4,500-hp natural gas-fired Cooper-Bessemer LSV-16G compressor engines (Units 701, 702, and 703) used for transportation of natural gas.

Mountainair CS also operates two (2) 335-hp natural gas-fired Ingersoll-Rand PSVG-6 generator engines. These generators are already utilizing best available control technology (BACT) for NO_x as Units 721 and 722 are controlled by non-selective catalytic reduction (NSCR). According to recent engine performance tests, NO_x emission rates are reduced by over 85% with the installed catalysts.

2.2 Clean Air Act and State Regulations

The engines subject to this analysis are subject to the following state and federal regulations:

20.2.61.109 NMAC

This regulation limits opacity to 20% applies to Stationary Combustion Equipment, such as engines, boilers, heaters, and flares unless your equipment is subject to another state regulation that limits particulate matter such as 20.2.19 NMAC (see 20.2.61.109 NMAC). Units 701, 702, 703, 721 and 722 are subject to this regulation.

20.2.82 NMAC

This regulation applies to all sources emitting hazardous air pollutants, which are subject to the requirements of 40 CFR Part 63, as amended through August 29, 2013.

MACT 40 CFR 63, Subpart ZZZZ

Facilities are subject to this subpart if they own or operate a stationary RICE, except if the stationary RICE is being tested at a stationary RICE test cell/stand. The generator engines (Units 721 and 722) at this station are stationary RICE that are existing engines subject to this subpart.

2.3 NO_x Emissions and Control Options

NO_x is generated from the combustion of natural gas used to power the applicable compressor engines. The exhaust gases are released to the atmosphere through stacks associated with each engine.

There are several different categories of NO_x formation in combustion processes. The combustion process taking place in RICE predominantly produces thermal NO_x[1] which is formed when nitrogen and oxygen unite during high temperature and high pressure combustion.[2]

While neither engine currently utilizes NO_x emission controls, two control options were assessed for the applicable engines: Low Emission Controls (LEC) and Selective Catalytic Reduction (SCR).

2.3.1 Low Emission Controls (LEC)

LEC is a combination of combustion controls in which various engine modifications, upgrades, and tuning methods provide lower emission combustion.

One upgrade includes increasing the air-to-fuel ratio (AFR) to reduce thermal NO_x formation by diluting combustion gases and lowering peak flame temperature. Upgrades to the AFR controller and turbocharger would be required. Adjusting ignition timing is another modification associated with LEC. This control delays ignition in the power stroke when the chamber is below its maximum pressure. This causes ignition at a lower temperature, thus lowering thermal NO_x formation during combustion. Other LEC options include installing cylinder heads fitted with pre-combustion chambers, larger intercooling applications, enhanced mixing, bypass valves, and increased ignition energy.[3]

A quotation provided by Cooper Machinery Services[10] shows that these LEC upgrades can lower NO_x emission rates to 2.5 g/hp-hr.

2.3.2 Selective Catalytic Reduction (SCR)

SCR is a post-combustion control for lean-burn combustion in which ammonia or urea is mixed with exhaust gases over a catalyst to (ideally) convert NO_x to nitrogen gas (N_2) and water (H_2O). While SCR has been applied to large boilers and turbines in the power generation industry, its application on new RICE in the gas transmission industry has been rare, and retrofitted applications for existing lean burn RICE had not occurred as of 2014.[4]

There are several factors that make SCR difficult for this application. Technical concerns, such as reagent injection control, exhaust temperature requirements, and variations in the exhaust NO/NO_2 ratio, pose limitations on the effectiveness and feasibility of SCR. NOx reduction may not be achieved, or even more ammonium sulfates may be emitted if the reagent feed rate and/or operating temperature is not precisely tuned to the fluctuating exhaust properties.[4]

Another challenge is that combustion byproducts and engine oil carryover often contaminate the catalytic elements in SCR applications. Routine cleaning and replacement as well as greater management are required for effective use.[4]

For these reasons, LEC is the preferred control method for Units 701, 702, and 703.

Table 2.1 below summarizes the control technology options.

Table 2.1 Summary of Potential NO_x Control Options

Technology	Description	Applicability	Feasibility	Performance (% reduction)
Low Emission Combustion (LEC)	Engine tuning improvements to increase combustion efficiency.	Units 701, 702, and 703	Potentially feasible	58-75%[10]
Selective Catalytic Reduction (SCR)	Exhaust control for lean-burn combustion that converts NO_x to nitrogen and water using ammonia or urea.	Units 701, 702, and 703	Not feasible based on documented difficulty implementing technology on RICE engines	70-90%[5]

2.3.3 Four Factor Analysis of Potential NO_x Control Options

2.3.3.1 Factor 1: Cost of Compliance

A quotation was provided by Cooper Machinery Services[10] which outlined the proposed LEC upgrades to Units 701, 702, and 703. Modifications include:

- Installing new cylinder heads fitted with pre-combustion chambers;
- Replacing existing water-cooled pulse exhaust manifold with a dry constant pressure exhaust manifold;
- Adding turbocharger bypass valves to exhaust manifold;
- Upgrading turbocharger to increase air-to-fuel ratio;
- Replacing current intercoolers with larger intercoolers; and
- Adding pilot fuel lines and pressure control for pre-combustion chamber fuel.

Cost effectiveness estimates from these upgrades range from $2,000 to $13,000 per ton of NO_x removed. See Appendix A for cost estimate calculations.

The capital costs for SCR, if one were to assume this was an 'achievable technology' for this application, are varied. There are a number of published cost estimates for typical coal- oil- and gas-fired medium to large sized boilers. The same cannot be said for a retrofit of a natural gas-fired compressor engine. In addition, the cost to retrofit an engine with SCR is much higher than an original SCR installation, which would apply to this analysis. SCR systems used to retrofit an existing unit increase in costs by 30%.[5] O&M costs may also be substantial depending on reagent usage,

catalyst replacement, and increased electrical usage. The cost effectiveness of SCR was estimated from $1,400 to $6,600 per ton removed.

See Appendix A for emission reductions and cost calculations.

Table 2.2 Summary of Cost Effectiveness of Potential NO_x Control Options

Control Option	Specific Design Parameters	Cost Effectiveness (2019 $/ton)	Factors Affecting Cost	Potential Applicability to Specific Affected Units
Low Emissions Controls (LEC)	Power cylinder heads, upgraded water coolers, high efficiency turbocharger, and miscellaneous on-engine assemblies.	$2,000 - $13,000	Annual hours of operation, target NO_x emission factor	Potentially applicable to units 701, 702, and 703
Selective Catalytic Reduction (SCR)	Exhaust control that converts NO_x to nitrogen and water using ammonia or urea.	$1,400 - $6,600	Contamination from byproducts, excessive routine maintenance, reagent usage	Potentially applicable to units 701, 702, and 703

2.3.3.2 Factor 2: Time Necessary for Compliance

According to NMED guidance, sources are generally given between two and five years to implement changes for compliance with new regulations and implementation of this LEC would fall within that timeframe. Although no specific data was found, it would be reasonable to assume that a two to five year period would also be appropriate for the installation of SCR.

2.3.3.3 Factor 3: Energy and Non-Air Impacts

The LEC technology does not require the handling or storage of hazardous materials and does not require changes that could create an energy demand penalty.

As described above, SCR systems require ammonia (aqueous and/or anhydrous) or urea-to-ammonia reagents. Anhydrous ammonia is considered a hazardous material, and would be subject to storage, transportation, and operational regulations.

2.3.3.4 Factor 4: Remaining Useful Life of the Source

Although the engines were manufactured in the 1960s, they are planned for continuous operation until they are no longer functional. The estimated service life of the assessed control equipment (LEC and SCR) is 25 years.[6] Based on this information, the control options are considered the

limiting factor for useful life of the source. The cost effectiveness for applying the control options considers this as the minimum lifespan.

3. References

1. U.S Environmental Protection Agency (USEPA). *Technical Support Document for Controlling NOx Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines*. March 2007.
2. U.S Environmental Protection Agency (USEPA). *Nitrogen Oxides (NOx), Why and How They Are Controlled.* November 1999.
3. INGAA Foundation, Inc. *Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOx Control for Natural Gas Transmission and Storage Compressor Drivers*. December 2017.
4. INGAA Foundation, Inc. *Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry.* July 2014.
5. U.S Environmental Protection Agency (USEPA). *EPA Air Pollution Control Technology Fact Sheet for SCR.*
6. U.S Environmental Protection Agency (USEPA). *EPA Air Pollution Control Cost Manual, 6th Edition*, USEPA Research Triangle Park, NC. January 2002.
7. Northeast States for Coordinated Air Use Management (NESCAUM). *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines*. December 2000.
8. U.S Environmental Protection Agency (USEPA). *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*. August 20, 2019.
9. Western Regional Air Partnership (WRAP). *Reasonable Progress Source Identification and Analysis Protocol, WRAP Regional Haze Planning Work Group – Control Measures Subcommittee*. February 2019.
10. Cost estimate from email correspondence with Bob Bailey with Cooper Machinery Services.

Appendix A
RICE Engine Baseline Emissions, Reductions, and Control Cost Analysis

Appendix A

RICE Engine Baseline Emissions, Reductions, and Control Cost Analysis
Mountainair Compressor Station- Torrance County, New Mexico

2016 EI	**Unit 701**		**LEC**		**SCR**	
Rated HP	4500		Rated HP	4500	Rated HP	4500
Operating Hours	1535		NOx Emission Factor [1] (g/hp-hr)	2.5	NOx Emission Factor (g/hp-hr)	0.60
Nox Emission Rate (lb/hr)	59.07		2016 Operating Hours	1535	2016 Operating Hours	1535
Nox emissions (ton/yr)	45.34		New Nox Emission Rate (lb/hr)	24.80	New NOx Emission Rate (lb/hr)	5.91
			Nox Emission Equivalent (ton/yr)	19.04	NOx Emission Equivalent (ton/yr)	4.53
			Difference (tons)	26.30	Difference (tons)	40.81
			% Reduction	**58%**	**% Reduction[3]**	**90%**
			2019 $/ton	**$ 13,002**	**2019 $/ton**	**$ 6,596**

2016 EI	**Unit 702**		**LEC**		**SCR**	
Rated HP	4500		Rated HP	4500	Rated HP	4500
Operating Hours	3116		NOx Emission Factor [1] (g/hp-hr)	2.5	NOx Emission Factor (g/hp-hr)	0.99
Nox Emission Rate (lb/hr)	98.03		2016 Operating Hours	3116	2016 Operating Hours	3116
Nox emissions (ton/yr)	152.73		New NOx Emission Rate (lb/hr)	24.80	New NOx Emission Rate (lb/hr)	9.80
			NOx Emission Equivalent (ton/yr)	38.64	NOx Emission Equivalent (ton/yr)	15.27
			Difference (tons)	114.09	Difference (tons)	137.46
			% Reduction	**75%**	**% Reduction[3]**	**90%**
			2019 $/ton	**$ 2,998**	**2019 $/ton**	**$ 2,114**

2016 EI	**Unit 703**		**LEC**		**SCR**	
Rated HP	4500		Rated HP	4500	Rated HP	4500
Operating Hours	4586		NOx Emission Factor [1] (g/hp-hr)	2.5	NOx Emission Factor (g/hp-hr)	1.02
Nox Emission Rate (lb/hr)	100.86		2016 Operating Hours	4586	2016 Operating Hours	4586
Nox emissions (ton/yr)	231.27		New NOx Emission Rate (lb/hr)	24.80	New NOx Emission Rate (lb/hr)	10.09
			NOx Emission Equivalent (ton/yr)	56.87	NOx Emission Equivalent (ton/yr)	23.13
			Difference (tons)	174.40	Difference (tons)	208.14
			% Reduction	**75%**	**% Reduction[3]**	**90%**
			2019 $/ton	**$ 1,961**	**2019 $/ton**	**$ 1,372**

[1] Lowest achievable emission factor, per Cooper Machinery quote
[2] SCR Reduction efficiency from *TECHNICAL SUPPORT DOCUMENT FOR CONTROLLING NOx EMISSIONS FROM STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES AND TURBINES,* Illinois Environmental Protection Agency, December 2017

LEC Cost	
Quote From Cooper Machinery Services - 10/17/19	
LEC Cost Description	**2019 $**
Total Capital Cost	1,800,000
Annual O&M Cost (estimate)	270,000
Total Annual Cost per Year	342,000

*Estimated useful life of LEC: 25 years
*Estimated Annual O&M cost as a percent of the Total Capital Investment: 15 %

SCR Cost						
	Unit 701		Unit 702		Unit 703	
SCR Cost Description	**1994 $**	**2019 $**	**1994 $**	**2019 $**	**1994 $**	**2019 $**
Total Capital Cost	634,900	1,100,282	634,900	1,100,282	634,900	1,100,282
Annual O&M Cost (estimate)	-	225,152	-	246,513	-	241,474
Total Annual Cost per Year	-	269,163	-	290,525	-	285,485

*Cumulative rate of Consumer Price Index (CPI) inflation from 1994 to 2019: 73.3 %
*Estimated useful life of SCR: 25 years

Appendix A

RICE Engine Baseline Emissions, Reductions, and Control Cost Analysis
Mountainair Compressor Station- Torrance County, New Mexico

Unit 701 SCR Costs			
Total Capital Cost (TCC)			Source
Lean Burn	*TCC = $310,000 + $72.70 * HP*		Pg III-30, NESCAUM, December 2000
Engine HP		4,500	
TCC (1994 dollars) =		$ 637,150.00	
CPI 1994		148.2	
CPI 2019		254.95	
TCC (2019 dollars) =		**$ 1,096,095.77**	
Total Annual Costs (TAC)			Source
Direct Annual Costs			
	Operator Labor Costs		
	Operator labor hours (hrs/day)	4	Sec 2.5, EPA Control Cost Manual
	Operator labor rate ($/hr)	$60	Sec 2.5, EPA Control Cost Manual
	Days of SCR operation (days/yr)	365	
Operator Labor		**$87,600**	
Supervisor	*15% of Operator*	**$13,140**	
	Materials		
	Ammonia ($Ammonia/yr)	**$ 24,389.69**	
	Catalyst ($/replacement catalyst layer)	**$ 9,740.81**	
	Maintenance		
	*Annual Maintenance Cost = 0.005*TCI*	**$ 5,480.48**	Eq. 2.57, EPA Control Cost Manual
Indirect Annual Costs	*Indirect Annual Cost = (Administrative Charges) + (Capitol Recovery)*		Eq. 2.68
Administrative Charges	*Administrative Charges = 0.03*((Operator Labor Cost)+0.4*(Annual Maintenance Cost))*	$ 3,087.97	Eq. 2.69
Capitol Recovery	*Capitol Recovery = CRF * TCI*	$ 81,713.23	Eq. 2.70
Capitol Recovery Factor (CRF)	$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$ n = 25 yrs, i = 5.5%	0.0745	Eq. 2.71
Indirect Annual Costs		**$ 84,801.20**	
Total Annual Costs (TAC)	*TAC = Direct Annual Costs + Indirect Annual Costs*	**$225,152**	

Unit 701 SCR Reagent and Catalyst Costs Backup Calculations				
			Unit	Source
Selective Catalytic Reduction		90%		
Uncontrolled emissions		59.07	lb/hr	2019 Stack Test
Engine Horsepower		4,500	hp	Permit
Engine Fuel Consumption		7728.00	Btu/hp-hr	2019 Stack Test
Max Heat Input (Q_B)		34.78	MMBTU/hr	Calculated
Stoichiometric Ratio Factor (SRF)		1.05		
Flue Gas Flow Rate ($q_{fluegas}$)		18853.18	acfm	2019 Stack Test
dscfm		7368.32	dscfm	2019 Stack Test
CF_plant		1		
Nox Removal Efficiency (η_{NOx})		90%		
N_{SCR}	*Number of SCRs*	1		
Catalyst Volume ($Vol_{catalyst}$)	$2.81*Q_B*\eta_{adj}*slip_{adj}*Nox_{adj}*S_{adj}*T_{adj}/N_{SCR}$	528.24	ft^3	Eq. 2.22, EPA Control Cost Manual
η_{adj}	$(0.2869+(1.058+\eta_{NOx}))$	2.24		Eq. 2.23, EPA Control Cost Manual
Slip	$(SRF-\eta_{NOx})$	0.15		
$Slip_{adj}$	*1.2835-(0.0567*slip)*	1.27		Eq. 2.24, EPA Control Cost Manual
NOx_{in}	*Uncontrolled emissions* / Q_B	1.70	lb/MMBTU	Calculated
NOx_{adj}	$0.8524+(0.3208*NOx_{in})$	1.40		Eq. 2.25, EPA Control Cost Manual
S, Sulfur in fuel		0.01		Section 2.5, EPA Control Cost Manual
S_{adj}	*0.9636+(0.0455*S)*	0.96		Eq. 2.26, EPA Control Cost Manual
SCR inlet temp		600	F	
SCR inlet temp		588.7	K	
T_{adj} for inlet T not - 700 F	*15.16-(0.03937*T)+(2.74E-5*T^2)*	1.402		Eq. 2.27, EPA Control Cost Manual
$A_{catalyst}$	$(q_{fluegas}/(16*60)$	19.64	ft^2	Eq. 2.28, EPA Control Cost Manual
n_{layer}	$V_{catalyst}/(h'_{layer}*A_{catalyst})$	8.68		Eq. 2.31, EPA Control Cost Manual
h_{layer}		4.1	ft	Eq. 2.32, EPA Control Cost Manual
h'_{layer}		3.1	ft	
$m_{reagent}$	$NOx_{in}*Q_B*\eta_{NOx}*SRF*MW_{reagent}/(MW_{NOx})$	20.63	lb/hr	Eq. 2.35, EPA Control Cost Manual
$MW_{reagent}$	*MW of ammonia*	17		
MW_{NOx}	*MW of NOx*	46		
C_{sol}	*Concentration of ammonia in aqueous solution*	0.29		Section 2.5, EPA Control Cost Manual
m_{sol}	$m_{reagent}/C_{sol}$	71.14	lb/hr	Eq. 2.36, EPA Control Cost Manual
ρ_{sol}		56	lb/ft^3	
v_{sol}		7.4805	gal/ft^3	
q_{sol}	$(m_{sol}/\rho_{sol})*7.4805$	9.50	gal/hr	Eq. 2.37, EPA Control Cost Manual
t_{op}		8760	hrs	
Vol_{tank}	$Voltank = q_{sol}*t_{op}$	83241.25	gallons	Eq. 2.38, EPA Control Cost Manual
cost of reagent		0.293	$/gallon	
Cost of reagent (per hour)		2.78	$/hr of ammonia	
Cost of reagent (per year)		**$ 24,389.69**	$/yr of ammonia	
Catalyst Cost (CC)		$ 160.00	$/ft^3	
Catalyst cost Replacement	$N_{SCR}*Vol_{catalyst}*(CC/n_{layer})$	**$ 9,740.81**	$/replacement layer/year	Eq. 2.63, EPA Control Cost Manual

Appendix A

RICE Engine Baseline Emissions, Reductions, and Control Cost Analysis
Mountainair Compressor Station- Torrance County, New Mexico

Unit 702 SCR Costs			
Total Capital Cost (TCC)			Source
Lean Burn	*TCC = $310,000 + $72.70 * HP*		Pg III-30, NESCAUM, December 2000
Engine HP		4,500	
TCC (1994 dollars) =		$ 637,150.00	
CPI 1994		148.2	
CPI 2019		254.95	
TCC (2019 dollars) =		**$ 1,096,095.77**	
Total Annual Costs (TAC)			Source
Direct Annual Costs			
	Operator Labor Costs		
	Operator labor hours (hrs/day)	4	Sec 2.5, EPA Control Cost Manual
	Operator labor rate ($/hr)	$60	Sec 2.5, EPA Control Cost Manual
	Days of SCR operation (days/yr)	365	
Operator Labor		**$87,600**	
Supervisor	*15% of Operator*	**$13,140**	
	Materials		
	Ammonia ($Ammonia/yr)	**$ 40,476.06**	
	Catalyst ($/replacement catalyst layer)	**$ 15,015.51**	
	Maintenance		
	*Annual Maintenance Cost = 0.005*TCI*	**$ 5,480.48**	Eq. 2.57, EPA Control Cost Manual
Indirect Annual Costs	*Indirect Annual Cost = (Administrative Charges) + (Capitol Recovery)*		Eq. 2.68
Administrative Charges	*Administrative Charges = 0.03*((Operator Labor Cost)+0.4*(Annual Maintenance Cost))*	$ 3,087.97	Eq. 2.69
Capitol Recovery	*Capitol Recovery = CRF * TCI*	$ 81,713.23	Eq. 2.70
Capitol Recovery Factor (CRF)	$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$ n = 25 yrs, i = 5.5%	0.0745	Eq. 2.71
Indirect Annual Costs		**$ 84,801.20**	
Total Annual Costs (TAC)	*TAC = Direct Annual Costs + Indirect Annual Costs*	**$246,513**	

Unit 702 SCR Reagent and Catalyst Costs Backup Calculations				
			Unit	Source
Selective Catalytic Reduction		90%		
Uncontrolled emissions		98.03	lb/hr	2019 Stack Test
Engine Horsepower		4,500	hp	Permit
Engine Fuel Consumption		7726.00	Btu/hp-hr	2019 Stack Test
Max Heat Input (Q_B)		34.77	MMBTU/hr	Calculated
Stoichiometric Ratio Factor (SRF)		1.05		
Flue Gas Flow Rate ($q_{fluegas}$)		29062.27	acfm	2019 Stack Test
dscfm		11358.3	dscfm	2019 Stack Test
CF_plant		1		
Nox Removal Efficiency (η_{NOx})		90%		
N_{SCR}	*Number of SCRs*	1		
Catalyst Volume ($Vol_{catalyst}$)	$2.81*Q_B*\eta_{adj}*slip_{adj}*Nox_{adj}*S_{adj}*T_{adj}/N_{SCR}$	664.03	ft^3	Eq. 2.22, EPA Control Cost Manual
η_{adj}	$(0.2869+(1.058+\eta_{NOx}))$	2.24		Eq. 2.23, EPA Control Cost Manual
Slip	$(SRF-\eta_{NOx})$	0.15		
$Slip_{adj}$	*1.2835-(0.0567*slip)*	1.27		Eq. 2.24, EPA Control Cost Manual
NOx_{in}	*Uncontrolled emissions / Q_B*	2.82	lb/MMBTU	Calculated
NOx_{adj}	$0.8524+(0.3208*NOx_{in})$	1.76		Eq. 2.25, EPA Control Cost Manual
S, Sulfur in fuel		0.01		Section 2.5, EPA Control Cost Manual
S_{adj}	*0.9636+(0.0455*S)*	0.96		Eq. 2.26, EPA Control Cost Manual
SCR inlet temp		600	F	
SCR inlet temp		588.7	K	
T_{adj} for inlet T not - 700 F	*15.16-(0.03937*T)+(2.74E-5*T^2)*	1.402		Eq. 2.27, EPA Control Cost Manual
$A_{catalyst}$	$(q_{fluegas}/(16*60)$	30.27	ft^2	Eq. 2.28, EPA Control Cost Manual
n_{layer}	$V_{catalyst}/(h'_{layer}*A_{catalyst})$	7.08		Eq. 2.31, EPA Control Cost Manual
h_{layer}		4.1	ft	Eq. 2.32, EPA Control Cost Manual
h'_{layer}		3.1	ft	
$m_{reagent}$	$NOx_{in}*Q_B*\eta_{NOx}*SRF*MW_{reagent}/(MW_{NOx})$	34.24	lb/hr	Eq. 2.35, EPA Control Cost Manual
$MW_{reagent}$	*MW of ammonia*	17		
MW_{NOx}	*MW of NOx*	46		
C_{sol}	*Concentration of ammonia in aqueous solution*	0.29		Section 2.5, EPA Control Cost Manual
m_{sol}	$m_{reagent}/C_{sol}$	118.05	lb/hr	Eq. 2.36, EPA Control Cost Manual
ρ_{sol}		56	lb/ft^3	
v_{sol}		7.4805	gal/ft^3	
q_{sol}	$(m_{sol}/\rho_{sol})*7.4805$	15.77	gal/hr	Eq. 2.37, EPA Control Cost Manual
t_{op}		8760	hrs	
Vol_{tank}	$Voltank = q_{sol}*t_{op}$	138143.55	gallons	Eq. 2.38, EPA Control Cost Manual
cost of reagent		0.293	$/gallon	
Cost of reagent (per hour)		4.62	$/hr of ammonia	
Cost of reagent (per year)		**$ 40,476.06**	$/yr of ammonia	
Catalyst Cost (CC)		$ 160.00	$/ft^3	
Catalyst cost Replacement	$N_{SCR}*Vol_{catalyst}*(CC/n_{layer})$	**$ 15,015.51**	$/replacement layer/year	Eq. 2.63, EPA Control Cost Manual

Appendix A

RICE Engine Baseline Emissions, Reductions, and Control Cost Analysis
Mountainair Compressor Station- Torrance County, New Mexico

Unit 703 SCR Costs			
Total Capital Cost (TCC)			Source
Lean Burn	*TCC = $310,000 + $72.70 * HP*		Pg III-30, NESCAUM, December 2000
Engine HP		4,500	
TCC (1994 dollars) =		$ 637,150.00	
CPI 1994		148.2	
CPI 2019		254.95	
TCC (2019 dollars) =		**$ 1,096,095.77**	
Total Annual Costs (TAC)			Source
Direct Annual Costs			
	Operator Labor Costs		
	Operator labor hours (hrs/day)	4	Sec 2.5, EPA Control Cost Manual
	Operator labor rate ($/hr)	$60	Sec 2.5, EPA Control Cost Manual
	Days of SCR operation (days/yr)	365	
Operator Labor		**$87,600**	
Supervisor	*15% of Operator*	**$13,140**	
	Materials		
	Ammonia ($Ammonia/yr)	**$ 41,644.55**	
	Catalyst ($/replacement catalyst layer)	**$ 8,807.60**	
	Maintenance		
	*Annual Maintenance Cost = 0.005*TCI*	**$ 5,480.48**	Eq. 2.57, EPA Control Cost Manual
Indirect Annual Costs	*Indirect Annual Cost = (Administrative Charges) + (Capitol Recovery)*		Eq. 2.68
Administrative Charges	*Administrative Charges = 0.03*((Operator Labor Cost)+0.4*(Annual Maintenance Cost))*	$ 3,087.97	Eq. 2.69
Capitol Recovery	*Capitol Recovery = CRF * TCI*	$ 81,713.23	Eq. 2.70
Capitol Recovery Factor (CRF)	$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$ n = 25 yrs, i = 5.5%	0.0745	Eq. 2.71
Indirect Annual Costs		**$ 84,801.20**	
Total Annual Costs (TAC)	*TAC = Direct Annual Costs + Indirect Annual Costs*	**$241,474**	

Unit 703 SCR Reagent and Catalyst Costs Backup Calculations				
			Unit	Source
Selective Catalytic Reduction		90%		
Uncontrolled emissions		100.86	lb/hr	2019 Stack Test
Engine Horsepower		4,500	hp	Permit
Engine Fuel Consumption		7079.00	Btu/hp-hr	2019 Stack Test
Max Heat Input (Q_B)		31.86	MMBTU/hr	Calculated
Stoichiometric Ratio Factor (SRF)		1.05		
Flue Gas Flow Rate ($q_{fluegas}$)		17046.96	acfm	2019 Stack Test
dscfm		6662.4	dscfm	2019 Stack Test
CF_plant		1		
Nox Removal Efficiency (η_{NOx})		90%		
N_{SCR}	*Number of SCRs*	1		
Catalyst Volume ($Vol_{catalyst}$)	$2.81*Q_B*\eta_{adj}*slip_{adj}*Nox_{adj}*S_{adj}*T_{adj}/N_{SCR}$	646.92	ft^3	Eq. 2.22, EPA Control Cost Manual
η_{adj}	$(0.2869+(1.058+\eta_{NOx}))$	2.24		Eq. 2.23, EPA Control Cost Manual
Slip	$(SRF-\eta_{NOx})$	0.15		
$Slip_{adj}$	*1.2835-(0.0567*slip)*	1.27		Eq. 2.24, EPA Control Cost Manual
NOx_{in}	*Uncontrolled emissions / Q_B*	3.17	lb/MMBTU	Calculated
NOx_{adj}	$0.8524+(0.3208*NOx_{in})$	1.87		Eq. 2.25, EPA Control Cost Manual
S, Sulfur in fuel		0.01		Section 2.5, EPA Control Cost Manual
S_{adj}	*0.9636+(0.0455*S)*	0.96		Eq. 2.26, EPA Control Cost Manual
SCR inlet temp		600	F	
SCR inlet temp		588.7	K	
T_{adj} for inlet T not - 700 F	*15.16-(0.03937*T)+(2.74E-5*T^2)*	1.402		Eq. 2.27, EPA Control Cost Manual
$A_{catalyst}$	$(q_{fluegas}/(16*60)$	17.76	ft^2	Eq. 2.28, EPA Control Cost Manual
n_{layer}	$V_{catalyst}/(h'_{layer}*A_{catalyst})$	11.75		Eq. 2.31, EPA Control Cost Manual
h_{layer}		4.1	ft	Eq. 2.32, EPA Control Cost Manual
h'_{layer}		3.1	ft	
$m_{reagent}$	$NOx_{in}*Q_B*\eta_{NOx}*SRF*MW_{reagent}/(MW_{NOx})$	35.22	lb/hr	Eq. 2.35, EPA Control Cost Manual
$MW_{reagent}$	*MW of ammonia*	17		
MW_{NOx}	*MW of NOx*	46		
C_{sol}	*Concentration of ammonia in aqueous solution*	0.29		Section 2.5, EPA Control Cost Manual
m_{sol}	$m_{reagent}/C_{sol}$	121.46	lb/hr	Eq. 2.36, EPA Control Cost Manual
ρ_{sol}		56	lb/ft^3	
ν_{sol}		7.4805	gal/ft^3	
q_{sol}	$(m_{sol}/\rho_{sol})*7.4805$	16.23	gal/hr	Eq. 2.37, EPA Control Cost Manual
t_{op}		8760	hrs	
Vol_{tank}	$Voltank = q_{sol}*t_{op}$	142131.58	gallons	Eq. 2.38, EPA Control Cost Manual
cost of reagent		0.293	$/gallon	
Cost of reagent (per hour)		4.75	$/hr of ammonia	
Cost of reagent (per year)		**$ 41,644.55**	$/yr of ammonia	
Catalyst Cost (CC)		$ 160.00	$/ft^3	
Catalyst cost Replacement	$N_{SCR}*Vol_{catalyst}*(CC/n_{layer})$	**$ 8,807.60**	$/replacement layer/year	Eq. 2.63, EPA Control Cost Manual



about GHD

GHD is one of the world's leading professional services companies operating in the global markets of water, energy and resources, environment, property and buildings, and transportation. We provide engineering, environmental, and construction services to private and public sector clients.

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January 23, 2020 Reference No. 11203587

Kerwin Singleton
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505

Dear Mr. Singleton:

Re: Additional Information for Four Factor Analysis
Mountainair Compressor Station
Transwestern Pipeline Company, LLC

GHD Services, Inc. (GHD) is submitting, on behalf of Transwestern Pipeline Company, LLC., responses to the New Mexico Environmental Department (NMED) request for additional information dated December 18, 2019 regarding the four-factor analysis completed for the Mountainair Compressor Station. These responses correspond to the NMED Regional Haze Second Planning Period Progress Analysis under the Clean Air Act (CAA) and Regional Haze Rule (40 CFR §51.300 to 51.309).

If you have any questions or concerns, please contact myself at (720) 974-0937 or Larry Campbell at (575) 625-8022.

Sincerely,

GHD



Sergio Guerra
Project Manager

SG/AW/1

Encl. Responses to NMED Request for Additional Information for Four-Factor Analysis

cc: Larry Campbell – Transwestern Pipeline Company, LLC.

GHD
14998 West 6th Avenue Suite 800 Golden Colorado 80401 USA
T 720 974 0935 **F** 720 974 0936 **W** www.ghd.com

REGISTERED COMPANY FOR ISO 9001 ENGINEERING DESIGN

Responses to NMED Additional Information Request Dated December 18, 2019

Four Factor Analysis
Mountainair Compressor Station
Transwestern Pipeline Company, LLC

Attachments Index

Attachment A – Cooper Machinery Quote for Low Emission Controls Retrofit
Attachment B – Selected Pages from Chapter 2 SCR, EPA Cost Control Manual (updated June 2019)
Attachment C – Updated Electronic Cost Analysis Spreadsheet
Attachment D – NMED Additional Information Request Letter dated December 18, 2019

1. The source category identified for analysis should include all sources that have PTE of 10 lb/hr of NO_x or SO_2; therefore the two (2) 335-hp natural gas-fired Ingersoll-Rand PSVG-6 generator engines also need to be evaluated for potential control options.
These generators were discussed in Section 2.1 of the original Four-Factor Analysis Report submitted to NMED on October 30, 2019. The two (2) 335 hp generator engines already have Non-Selective Catalytic Reduction (NSCR) controls installed on them to reduce NOx emissions, which is considered BACT. Additionally, the permit for the facility states that only one generator may operate at a time except during start-up/shutdown transitions, so the generators are scheduled to operate for limited hours. We contacted Kerwin Singleton of NMED on 01/13/2020 to confirm that these generators will not need to be evaluated for further potential control options and he verbally agreed.

2. Provide the basis for the Operational and Maintenance (O&M) Costs used in the cost analysis.
The basis for O&M costs is that they are a percentage of the initial capital cost investment. The O&M percentage was calculated based on a four-factor cost analysis for a facility in North Dakota performed on similar controls for similar equipment. The primary reference for that North Dakota cost analysis is the EPA Air Pollution Control Cost Manual, 7th Edition, Sections 2.5 and 2.6.

3. Please provide the details regarding Good Combustion Practices (GCP) and the routine maintenance schedule and procedures that are currently used to mitigate NO_x emissions and are proposed as a feasible control.
Energy Transfer performs regular inspection and maintenance activities for the equipment on site. Maintenance schedule and procedures and the associated tracking, monitoring, testing, and recordkeeping are required in the facility operating permit.

4. Consider and include a discussion on the feasibility and cost of technology that limits engine capacity to reduce NO_x emissions. Also evaluate limiting operating hours or consider shutting down engines that are no longer needed to reduce emissions.
Energy Transfer cannot reduce the engine capacity or hours of operation for Units 701, 702, and 703 due to the operational needs of the site.

5. Please consider and include a discussion on the feasibility of replacing natural gas fueled engines with commercial electric powered compressors.
All electricity for this site is generated by the two (2) 335-hp natural gas-fired Ingersoll-Rand PSVG-6 generator engines, which are needed because the site does not have access to the electric grid. Since electricity is supplied by generators instead of the electric grid, it is not feasible to use electric powered compressors at this facility.

6. The four-factor analysis proposes a 2.5 grams per brake horsepower-hour (g/bhp-hr.) NO_X emission rate achievable by Low Emission Controls for Cooper Bessemer engines at the facility. Please provide a vendor quote with cost and control efficiency for Low Emission Controls.
Please see attached Cooper Machinery quote which includes a 2.5 g/hp-hr emission factor (Attachment A).

7. Consider and include a discussion of variations of Clean Burn Technology (CBT) used to reduce NO_X emissions that may be less expensive than the full CBT packages proposed. Please include cost and efficiencies in the analysis.
Please see correspondence with and quote from Cooper Machinery (Attachment A) which states that the full package of CBT is necessary to achieve emission reductions. The retrofit upgrades presented and quoted by Cooper include:

1) Install new cylinder heads fitted with precombustion chambers
2) Replace existing water-cooled pulse type exhaust manifold with a dry constant pressure manifold.
3) Add bypass valve to exhaust manifold to permit control of intake manifold pressure by bypassing some exhaust from the turbocharger.
4) Upgrade turbocharger to flow more air into combustion chamber
5) Remove existing expansion turbo-coolers.
6) Replace small intercoolers with larger intercoolers.
7) Add pilot fuel lines and pressure control for precombustion chamber fuel

8. Please verify and provide documentation that control systems have not yet been developed for selective catalytic reduction (SCR) controls that can handle variable load engines. This appears to be one main reason that SCR has not been implemented on two-stroke lean burn (2SLB) internal combustion engines in oil and gas midstream operations.
SCR technology was developed for combustion equipment and has been implemented on boilers which generally have lower emissions than compressor engines. Based on the INGAA source referenced in the Four Factor Analysis, SCR technology has been universally determined as not practical for engines due to the unreasonable cost of retrofitting (more expensive than a new installation) and the burdensome effort required to handle the hazardous materials involved (INGAA, Availability and Limitations of NOx Emission Control Resources, 2014). This includes the generation, capturing, disposal of, and replacing of catalytic reagants. Our understanding is that for these reasons and based on the information provided in Sections 2.3.2 and 2.3.3 of the Four-Factor Analysis dated October 30, 2019, SCR control systems are not a practical control measure for the compressor engines at this facility.

Chapter 2 of the EPA SCR cost manual (updated June 2019) (Attachment B) supports the information above. The only example provided for SCR technology used on a RICE engine occurred in 1994 on a new 1,800 hp diesel-fired engine but not for a natural gas engine. All other examples of SCR applications were for other types of combustion equipment often in industries other than oil & gas.

9. Please provide vendor quotes that include the cost information, recommendations, and equipment specifications for the engine control cost estimates.
Please see attached Cooper Machinery quote (Attachment A).

10. Provide any electronic spreadsheets used for control technology calculations.
Please see attached updated electronic spreadsheet (Attachment C).

Attachment A

Andy White

From: Bailey, Bob (Cooper, Non-GE) <Bob.Bailey@bhge.com>
Sent: Tuesday, January 14, 2020 8:54 PM
To: Andy White
Cc: Sergio Guerra; Phil Horn
Subject: RE: Engine Retrofit - Low Emission Controls - Roswell and Mountainair

Andrew, to achieve lower emissions the full package must be done.

Installing jetcell heads will definitely make the engines run with greater stability, however, this the improved combustion will result in lower exhaust temperatures as more fuel will go to providing effective work. The lower temperatures will reduce the energy needed to drive the turbocharger so there will not be sufficient air to lean out the air/fuel mixture necessary to reduce NOx emissions.

To achieve the leaner air/fuel mixture with jetcell heads requires a higher efficiency constant pressure turbocharger with a constant pressure exhaust manifold. To be able to control air fuel ratio, it is necessary to control the turbocharger speed. To do this we install a wastegate before the turbocharger which allows some of the exhaust gas to bypass the turbocharger. This is not possible with the pulse type manifold currently installed on the engine because it has individual pipes for each cylinder collecting into multiple inlets on the turbine casing.

The higher air flow from the turbocharger will require larger coolers to be installed to keep intake manifold temperature within limits.

We have provided a quick budget number with some consideration that this project may not be done for several years. Is there an estimated schedule for the job?

Best regards
Bob Bailey

From: Andrew.White2@ghd.com <Andrew.White2@ghd.com>
Sent: Friday, January 10, 2020 5:33 PM
To: Bailey, Bob (Cooper, Non-GE) <Bob.Bailey@bhge.com>
Cc: Sergio Guerra <Sergio.Guerra@ghd.com>; Phillip.Horn@ghd.com
Subject: EXT: RE: Engine Retrofit - Low Emission Controls - Roswell and Mountainair

Hi Bob,

Thanks for providing the general LEC quote below to my colleague Phil Horn back in October and hope 2020 is starting well for you.

The State of Mexico has asked for Cooper to now provide cost estimates for each of the individual upgrades mentioned below (i.e. install new cylinder heads, replace manifold, add bypass valve, etc.). They are interested in whether a “partial package” of upgrades might be more cost effective for controlling NOx emissions than the full $1,800,000 package. Would you be able to provide this for us?

Thanks very much for your help with this and please let me know any questions.

Best regards,

Andy White
720-974-0965

From: Bailey, Bob (Baker Hughes) <Bob.Bailey@bhge.com>
Sent: Thursday, October 17, 2019 9:56 PM
To: Phil Horn <Phillip.Horn@ghd.com>
Subject: RE: Engine Retrofit - Low Emission Controls - Roswell and Mountainair

Hello Phil

After doing some discussions we can upgrade these engines by doing following:

Install new cylinder heads fitted with precombustion chambers

Replace existing water cooled pulse type exhaust manifold with a dry constant pressure manifold.

Add bypass valve to exhaust manifold to permit control of intake manifold pressure by bypassing some exhaust from the turbocharger.

Upgrade turbocharger to flow more air into combustion chamber

Remove existing expansion turbo-coolers.

Replace small intercoolers with larger intercoolers.

Add pilot fuel lines and pressure control for precombustion chamber fuel.

Considering the age and condition of the engines, these changes will allow reliable operation with NoX emissions of 2.5 gm/bhp-hr at full load. This would be better stated in lb/hr and I will get you that value tomorrow.

Budget price for this is US$ 1,800,000 per engine.

I trust this will meet your needs for now (I will get you lb-hr value tomorrow).

Best regards
Bob Bailey

From: Phillip.Horn@ghd.com <Phillip.Horn@ghd.com>
Sent: Thursday, October 17, 2019 10:42 AM
To: Bailey, Bob (Baker Hughes) <Bob.Bailey@bhge.com>
Subject: EXT: RE: Engine Retrofit - Low Emission Controls - Roswell and Mountainair

Hi Bob,

Were you able to get a general quote yesterday?

Attachment B

Chapter 2
Selective Catalytic Reduction

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Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

David D. Randall, Karen S. Schaffner, Carrie Richardson Fry
RTI International
Research Triangle Park, NC 27709

June 2019

DISCLAIMER

This document includes references to specific companies, trade names and commercial products. Mention of these companies and their products in this document is not intended to constitute an endorsement or recommendation by the U.S. Environmental Protection Agency.

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2. SELECTIVE CATALYTIC REDUCTION

2.1 Introduction

Selective catalytic reduction (SCR) has been applied to stationary source fossil fuel-fired combustion units for emission control since the early 1970s and is currently being used in Japan, Europe, the United States, and other countries. In the U.S. alone, more than 1,000 SCR systems have been installed on a wide variety of sources in many different industries, including utility and industrial boilers, process heaters, gas turbines, internal combustion engines, chemical plants, and steel mills [1]. Other sources include fluid catalytic cracking units (FCCUs), ethylene cracker furnaces, nitric acid plants, catalyst manufacturing processes, nitrogen fixation processes, and solid/liquid or gas waste incinerators [2, 3]. In the U.S., SCR has been installed on more than 300 coal-fired power plants ranging in size from less than 100 megawatt equivalent (MWe) to 1,400 MWe [1, 4]. Other combustion sources with large numbers of SCR retrofits include more than 50 gas-fired utility boilers ranging in size from 147 MWe to 750 MWe, more than 50 industrial boilers and process heaters (both field-erected and packaged units), and more than 650 combined cycle gas turbines [1]. SCR can be applied as a stand-alone nitrogen oxides (NO_x) control or with other technologies, including selective non-catalytic reduction (SNCR)[1] and combustion controls such as low NO_x burner (LNB) and flue gas recirculation (FGR) [2].

SCR is typically implemented on stationary source combustion units requiring a higher level of NO_x reduction than achievable by selective non-catalytic reduction (SNCR) or combustion controls. Theoretically, SCR systems can be designed for NO_x removal efficiencies up close to 100 percent. In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NO_x controls such as LNB or FGR that achieve relatively low emissions on their own. The outlet concentration from SCR on a utility boiler is rarely less than 0.04 lb/million British thermal units (MMBtu) [1].[2] In comparison, SNCR units typically achieve approximately 25 to 75 percent reduction efficiencies [5].

Either ammonia or urea may be used as the NO_x reduction reagent in SCR systems. Urea is generally converted to ammonia before injection. Results of a survey of electric utilities that operate SCR systems indicated that about 80 percent use ammonia (anhydrous and aqueous), and the remainder use urea [4]. A survey of coal-fired power plants that control NO_x emissions using either SCR or SNCR found anhydrous ammonia use exceeds aqueous ammonia use by a ratio of 3 to 1. Nearly half of these survey respondents also indicated that price is their primary consideration in the choice of reagent; safety is the primary consideration for about 25 percent of the operators [6].

SCR capital costs vary by the type of unit controlled, the fuel type, the inlet NO_x level, the outlet NO_x design level, and reactor arrangement. Capital costs also rose between 2000 and 2010 (at least for utility boiler applications), even after scaling all data to 2011 dollars (2011$).

[1] A hybrid SNCR/SCR system was demonstrated at the AES Greenidge Power Plant in 2006. However, no hybrid SNCR/SCR systems are currently known to be operating as of February 2016.

[2] Data in the Clean Air Markets Division (CAMD) database also suggest SCR units rarely achieve emissions less than 0.04 lb/MMBtu.

For a small number of early SCR retrofits on utility boilers prior to 2000, the average costs were about $100/kilowatt (kW), in 2011$, and there was little scatter in the data. From 2000 to 2007, the SCR costs for 32 utility boilers ranged from about $100/kW to $275/kW (2011$), and a slight economy of scale was evident (i.e., using a regression equation, costs ranged from about $200/kW for a 200 MW unit to $160/kW for an 800 MW unit). For 2008 to 2011, the average SCR costs exhibited great variability and again a modest economy of scale was evident (i.e., about $300/kW for a 200 MW unit to $250/kW for an 800 MW unit; 2011$). For eight utility boilers either installed in 2012 or projected to be installed by 2014, the SCR costs ranged from about $270/kW to $570/kW (2011$). The generating capacity for these units ranged from 400 MW to 800 MW [7]. Typical operation and maintenance costs are approximately 0.1 cents per kilowatt-hour (kWh) [8, 9]. Table 2.1a provides capital cost estimates for electric utility boilers, and Table 2.1b presents capital cost estimates for SCR applications of various sizes in several other industry source categories.

The procedures for estimating costs presented in this report are based on cost data for SCR retrofits on existing coal-, oil-, and gas-fired boilers for electric generating units larger than 25 MWe (approximately 250 MMBtu/hr). Thus, this report's procedure estimates costs for typical retrofits of such boilers. The methodology for utility boilers also has been extended to large industrial boilers by modifying the capital cost equations and power consumption (electricity cost) equations to use the heat input capacity of the boiler instead of electric generating capacity.[3] The procedures to estimate capital costs are not directly applicable to sources other than utility and industrial boilers. Procedures to estimate annual costing elements other than power consumption are the same for SCR units in any application. The cost of SCR as part of a new plant often is likely to be less than the cost for retrofitting an SCR at an existing plant. Appropriate factors to estimate the cost of a new plant SCR have been included. In addition, the cost procedures in this report reflect individual SCR applications. Retrofitting multiple boilers with SCR can allow for some economies of scale for installation, thus yielding some reduction in capital costs per SCR application. The cost methodology incorporates certain approximations; consequently, it should be used to develop study-level accuracy (±30 percent) cost estimates of SCR applications. Such accuracy in the cost methodology is consistent with the accuracy of the cost estimates for the other control measures found in this Cost Manual as stated in Section 1.

In the cement industry, pilot tests in the 1970s and 1990s showed that SCR could be a feasible control technology for cement kilns. Building on that experience, SCRs were first installed in Europe in 2001. Today, SCR has been successfully implemented at seven European cement plants in Solnhofer, Germany (operated from 2001 until 2006), Bergamo, Italy (2006), Sarchi, Italy (2007), Mergelstetten, Germany (2010), Rohrdorf, Germany (2011), Mannersdorf, Austria (2012), and Rezatto, Italy (2015) [10, 11, 12]. As of 2015, there is only one cement plant in the U.S. that has installed an SCR. This SCR began operation in 2013 and is installed after an electrostatic precipitator. The control efficiency for the system is reported to be about 80 percent, which is consistent with SCR applications on European kilns. SCRs have not seen widespread use in the U.S. cement industry mainly due to industry concerns regarding potential problems caused by high-dust levels and catalyst deactivation by high sulfur trioxide (SO_3) concentrations

[3] The term "industrial" boilers as used in the Control Cost Manual includes industrial, commercial, and institutional (or ICI) boilers, unless otherwise noted.

from pyritic sulfur found in the raw materials used by U.S. cement plants. The SO_3 could react with calcium oxide in the flue gas to form calcium sulfate and with ammonia to form ammonium bisulfate. The calcium sulfate could deactivate the catalyst, while the ammonium bisulfate could cause catalyst plugging. There have been concerns expressed about the potential for catalyst poisoning by sodium, potassium, and arsenic trioxide. Finally, other concerns expressed are that dioxins and furans may form in the SCR due to combustion gases remaining at temperatures between 450 degrees Fahrenheit (°F) and 750°F. These and other concerns regarding the implementation of SCR to the cement industry are discussed in detail in "Alternative Control Techniques Document Update – NO_x Emissions from New Cement Kilns" [10]. Due to the small number of SCRs installed at cement plants, information on capital and operating costs for SCRs at cement plants is limited. The installation and operating costs for the SCR installed at the U.S. plant in 2013 are not publicly available at this time. In general, we expect the capital and operating costs would be higher than for low-dust applications due to the need to install catalyst cleaning equipment for SCR systems installed in high-dust configurations and for heating the flue gas in low-dust, tail-end configurations.

Table 2.1a: Summary of SCR Cost Data for Utility Boilers

Source Category	Unit Size	Fuel Type	Capital Cost			$ Year	Comments	Reference
			Min	Avg	Max			
Electric Generating Units	NA[a]	NA	$55/kW		$140/kW	<2000$[b]	Retrofit costs.	[13]
	~300-1,400 MW	NA	~$70/kW		~$120/kW	<2000$[b]	Retrofit costs. Six boilers. No economy of scale.	[13]
	150–1,000 MW	Coal	$80/kWnet[c]		$160/kWnet[c]	2002$	Retrofit costs. Author of referenced document scaled original costs to 2002 dollars. More than 20 boilers. Little to no economy of scale.	[14]
	NA	Coal	$60/kW	$100kW	$200/kW	<2004$[b]	Retrofit costs	[15]
	<300 MW	Coal		$167/kW	$186/kW	<2004$	Costs for 26 boilers.	[16]
	301–600 MW	Coal		$148/kW	$192/kW	<2004$	Costs for 15 boilers.	[16]
	601–900 MW	Coal		$124/kW	$221/kW	<2004$	Costs for 22 boilers.	[16]
	>900 MW	Coal		$118/kW	$195/kW	<2004$	Costs for 9 boilers.	[16]
	100–399 MW	Coal	$70/kW	$123/kW	~$175/kW	<2004$[b]	Costs for 5 boilers.	[17]
	400–599 MW	Coal	$73/kW	$103/kW	~$160/kW	<2004$[b]	Costs for 8 boilers.	[17]
	600–899 MW	Coal	$56/kW	$81/kW	~$100/kW	<2004$[b]	Costs for 9 boilers.	[17]
	>900 MW	Coal	~$80/kW	$117/kW	~$190/kW	<2004$[b]	Costs for 10 boilers.	[17]
	191 MW	Coal		$149/kW		2006$	Retrofit costs.	[18]
	~100 MW-~800MW	NA	~$125/kW	$275/kW	~$440/kW	2008$	Retrofit costs for 15 boilers installed in 2008 to 2010. Most costs between $200/kW and $350/kW. Slight economy of scale—regression average about $340/kW for 100 MW to $250/kW for 800 MW.	[8]
	~400 MW to ~800 MW	NA	~$270/kW	~$420/kW	~560/kW	2011$	Retrofit costs for 8 boilers either installed in 2012 or projected to be installed by 2014.	[7]

[a] Not Available.

[b] Year of reference.

[c] Net kilowatts.

Table 2.1b: Summary of SCR Cost Data for Miscellaneous Industrial Sources

Source Category	Unit Size	Fuel Type	Capital Cost: average (range)	$ Year	Actual, Vendor Quote, or Estimated?	Comments	Reference
Industrial-Commercial Boilers	350 MMBtu	Coal	NA ($10,000–$15,000/MMBtu/hr)	1999$	Estimated	Retrofit costs. Authors of referenced document estimated the low end of the range assuming a cost of about $100/kW for a 100 MW (1000 MMBtu/hr) utility boiler and assuming that economies of scale would be greater for utility boilers than for industrial boilers (so that the cost for a 350 MMBtu/hr industrial boiler would be comparable to or greater than the cost for a 1000 MMBtu/hr utility boiler on a $/MMBtu basis).	[19]
	100–1,000 MMBtu/hr	Coal	NA ($7,300–$14,600/MMBtu/hr)	1999$	Estimated	Retrofit costs. Generally costs available for one boiler with each type of fuel. Authors of referenced document estimated costs for other sizes assuming ratio of small-to-large $/MMBtu costs are related to ratio of large to small heat inputs raised to the 0.3 power.	[20]
	100–1,000 MMBtu/hr	Oil	NA ($5,550–$11,100/MMBtu/hr)	1999$	Estimated		[20]
	100–1,000 MMBtu/hr	Gas	NA ($4,010–$8,010/MMBtu/hr)	1999$	Estimated		[20]
	100 MMBtu/hr	Gas	NA ($7,500/MMBtu/hr)	1999$[b]	Vendor	Cited source in reference [15] is an unpublished letter from a vendor.	[19]
	350 MMBtu	Oil, Gas, or Wood	NA ($4,000–$6,000/MMBtu/hr)	1999$	Estimated		[21]
	57 MMBtu/hr	Wood	NA (>$560,000 and $9,500/MMBtu/hr)	1999$[c]	Actual/ Estimate	Costs for a new boiler.	[19]
	321 MMBtu/hr	Wood	NA ($1,980/MMBtu/hr)	2006$	Likely Estimated		[22]
Petroleum Refining – Steam Boilers	650 MMBtu/hr	Gas or refinery fuel gas	NA ($3,100–$25,800/MMBtu)	2004$ [c]	Estimated	Retrofit costs. Equipment costs based on range of costs found in literature search (references were not provided). Installation costs estimated using factors from the Control Cost Manual for thermal and catalytic incinerators.	[23]
Petroleum Refining – Process Heaters	350 MMBtu/hr	Gas/refinery fuel gas	NA ($3,100–$25,800/MMBtu)	2004$ [c]	Estimated	Same comment as above.	[23]
	350 MMBtu/hr	Refinery oil	NA ($3,100–$25,800/MMBtu)	2004$ [c]	Estimated	Same comment as above.	[23]

Source Category	Unit Size	Fuel Type	Capital Cost: average (range)	$ Year	Actual, Vendor Quote, or Estimated?	Comments	Reference
	10 MMBtu/hr	Gas or refinery fuel gas/NG combo	$19,200/MMBtu ($12,000–$26,500/MMBtu)	1999[b]	Vendor/ Estimated	Costs are based primarily on quotes from two vendors (and additional discussions). Authors of the referenced report added costs for fan, motor, and ductwork costs based on procedures in the Control Cost Manual.	[24]
	50 MMBtu/hr	Gas or refinery fuel gas/NG combo	$5,140/MMBtu ($4,020–$6,280/MMBtu)	1999[b]	Vendor/ Estimated	Same comment as above.	[24]
	75 MMBtu/hr	Gas or refinery fuel gas/NG combo	$4,190/MMBtu ($3,440–$4,950/MMBtu)	1999[b]	Vendor/ Estimated	Same comment as above.	[24]
	150 MMBtu/hr	Gas or refinery fuel gas/NG combo	$2,730/MMBtu ($2,570–$2,880/MMBtu)	1999[b]	Vendor/ Estimated	Same comment as above.	[24]
	350 MMBtu/hr	Gas or refinery fuel gas/NG combo	$1,550/MMBtu ($1,520–$1,570/MMBtu)	1999[b]	Vendor/ Estimated	Same comment as above.	[24]
	68 MMBtu/hr (Two 32 MMBtu/hr)	Refinery fuel gas	NA ($22,100/MMBtu)	1991	Actual	Retrofit costs.	[19]
Petroleum Refining – FCCU	70,000 barrels/stream day (bbl/stream day)	NA	NA ($9.0 million)	2004$[c]	Vendor	Estimated cost by vendor (for 90 percent reduction).	[3]
	27,000 bbl/stream day	NA	NA ($8-$12 million)	2009	Estimated		[25]

Source Category	Unit Size	Fuel Type	Capital Cost: average (range)	$ Year	Actual, Vendor Quote, or Estimated?	Comments	Reference
	<20,000->100,000 bbl/stream day	NA	NA (order of magnitude range; low end higher than two entries above)	2005 to 2010	Actual	Costs reported by 6 petroleum refining companies for 7 FCCUs in responses to EPA ICR. One new, 6 retrofits.	[26]
	NA	NA	NA ($20 million)	2006	Actual	Approximate average cost for SCR retrofits at several refineries	[27]
Portland Cement (dry kilns)	1.09 million short tpy clinker	NA	NA ($6.9 per short ton clinker)	2006[a]	Estimated	Retrofit cost. Estimate based primarily on SCR procedures for boilers in fifth edition of the Control Cost Manual. Clinker capacity obtained from the second reference.	[28,29]
	1.13 million short tpy clinker	NA	NA ($5.9 per short ton clinker)	2006[a]	Estimated	Same comment as above.	[28,29]
	2.16 million short tpy clinker	NA	NA ($3.9 per short ton clinker)	2006[a]	Estimated	Same comment as above.	[28,29]
	1.4 million short tpy clinker	NA	NA ($5.9 per short ton clinker)	2004	Not clear	Retrofit cost for European kiln. Cost in euros converted to dollars assuming a ratio of $1.3/euro.	[30]
	1.055 million tpy clinker	NA	NA ($4.4 per short ton clinker)	2004	Estimated	Cost for new kiln.	[31]
	1.095 million short tpy clinker	NA	NA ($4.4 per short ton clinker)	2011	Estimated	Cost for new kiln. Cost based on quote for the SCR equipment, and standard installation factors from the Control Cost Manual for other types of control devices.	[32]
Portland Cement (wet kilns)	0.3 million short tpy clinker	NA	NA ($17.5 per short ton clinker)	2006[a]	Estimated	Retrofit costs for 4 kilns. Rated clinker production capacity obtained from the second reference.	[28,33]
	0.320 million short tpy clinker		NA ($15.6-$16.6 per short ton clinker)	2006[a]	Estimated	Retrofit costs for 3 kilns. Rated clinker production capacity obtained from second reference.	[28,29]

Source Category	Unit Size	Fuel Type	Capital Cost: average (range)	$ Year	Actual, Vendor Quote, or Estimated?	Comments	Reference
Gas Turbine, Simple Cycle	NA	Gas	NA ($50-$70/kW)	1999$[a]	Vendor	Retrofit costs.	[19]
	80 MW	Gas	NA ($51/kW)	1999$[a]	Vendor	Retrofit cost, excluding balance of plant costs.	[19]
	2 MW	Gas	NA ($237/kW)	1999$[a]	Vendor	Retrofit cost.	[19]
	12 MW	Gas	NA ($167/kW)	1999$[a]	Vendor	Retrofit cost.	[19]
Internal Combustion Engine	1,800 hp[d]	Diesel (No. 2 fuel oil)	NA ($0.18 million)	1994	Actual	New cost	[19]

[a] Year of reference.

[b] Year analysis was conducted (assumed vendor contacts were made that year).

[c] Commission year of the SCR.

[d] Horsepower.

Attachment C

Electronic Spreadsheet Provided Separately

Attachment C
RICE Engine Baseline Emissions, Reductions, and Control Cost Analysis
Mountainair Compressor Station- Torrance County, New Mexico

2016 EI	Unit 701		LEC		Electric Replacement	
Rated HP	4500		Rated HP	4500	Rated HP	4500
Operating Hours	1535		NOx Emission Factor [1] (g/hp-hr)	2.5	NOx Emission Factor [1] (g/hp-hr)	0
Nox Emission Rate (lb/hr)	59.07		2016 Operating Hours	1535	2016 Operating Hours	1535
Nox emissions (ton/yr)	45.34		New Nox Emission Rate (lb/hr)	24.80	New Nox Emission Rate (lb/hr)	0.00
			Nox Emission Equivalent (ton/yr)	19.04	Nox Emission Equivalent (ton/yr)	0.00
			Difference (tons)	26.30	Difference (tons)	45.34
			% Reduction	**58%**	**% Reduction**	**100%**
			2019 $/ton	**$ 13,002**	**2019 $/ton**	**$ 27,293**

2016 EI	Unit 702		LEC		Electric Replacement	
Rated HP	4500		Rated HP	4500	Rated HP	4500
Operating Hours	3116		NOx Emission Factor [1] (g/hp-hr)	2.5	NOx Emission Factor [1] (g/hp-hr)	0
Nox Emission Rate (lb/hr)	98.03		2016 Operating Hours	3116	2016 Operating Hours	3116
Nox emissions (ton/yr)	152.73		New NOx Emission Rate (lb/hr)	24.80	New Nox Emission Rate (lb/hr)	0.00
			NOx Emission Equivalent (ton/yr)	38.64	Nox Emission Equivalent (ton/yr)	0.00
			Difference (tons)	114.09	Difference (tons)	152.73
			% Reduction	**75%**	**% Reduction**	**100%**
			2019 $/ton	**$ 2,998**	**2019 $/ton**	**$ 8,102**

2016 EI	Unit 703		LEC		Electric Replacement	
Rated HP	4500		Rated HP	4500	Rated HP	4500
Operating Hours	4586		NOx Emission Factor [1] (g/hp-hr)	2.5	NOx Emission Factor [1] (g/hp-hr)	0
Nox Emission Rate (lb/hr)	100.86		2016 Operating Hours	4586	2016 Operating Hours	4586
Nox emissions (ton/yr)	231.27		New NOx Emission Rate (lb/hr)	24.80	New Nox Emission Rate (lb/hr)	0.00
			NOx Emission Equivalent (ton/yr)	56.87	Nox Emission Equivalent (ton/yr)	0.00
			Difference (tons)	174.40	Difference (tons)	231.27
			% Reduction	**75%**	**% Reduction**	**100%**
			2019 $/ton	**$ 1,961**	**2019 $/ton**	**$ 5,351**

[1] Lowest achievable emission factor, per Cooper Machinery quote

LEC Cost	
Quote From Cooper Machinery Services - 10/17/19	
LEC Cost Description	**2019 $**
Total Capital Cost	1,800,000
Annual O&M Cost (estimate)	270,000
Total Annual Cost per Year	342,000

Electric Replacement	
Assume $1 million per electric engine	
Cost Description	**2019 $**
Total Capital Cost	6,512,932
Annual O&M Cost (estimate)	976,940
Total Annual Cost per Year	1,237,457

*Estimated useful life of LEC or Electric Replacement: 25 years
*Estimated Annual O&M cost as a percent of the Total Capital Investment: 15 %

Attachment D

NEW MEXICO
ENVIRONMENT DEPARTMENT

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December 18, 2019

Mr. Larry Campbell
Transwestern Pipeline
6381 Main Street
Roswell, NM 88201

Sent by electronic mail to: larry.campbell@energytransfer.com

Subject: Request for Additional Information for Four-Factor Analyses under the Regional Haze Program

Dear Mr. Campbell:

This letter requests additional information for the Transwestern Mountainair No. 7 Compressor Station Four-Factor Analysis report that was received by the New Mexico Environment Department (NMED) Air Quality Bureau (AQB) on November 1st, 2019. Pursuant to NMED's Regional Haze Guiding Principles, the four-factor analysis must consider new ideas that potentially offer better solutions to problems and must evaluate the newest engineering methods and technology advances in potential control measures.

Based on our initial review, the NMED requires additional information, analyses and clarifications on Transwestern Pipeline's four-factor analysis as follows.

1. The source category identified for analysis should include all sources that have PTE of 10 lbs./hr. of NO_X or SO_2; therefore the two (2) 335-hp natural gas-fired Ingersoll-Rand PSVG-6 generator engines also need to be evaluated for potential control options.
2. Provide the basis for the Operational and Maintenance (O&M) Costs used in the cost analysis.
3. Please provide the details regarding Good Combustion Practices (GCP) and the routine maintenance schedule and procedures that are currently used to mitigate NO_X emissions and are proposed as a feasible control.
4. Consider and include a discussion on the feasibility and cost of technology that limits engine capacity to reduce NO_X emissions. Also evaluate limiting operating hours or consider shutting down engines that are no longer needed to reduce emissions.
5. Please consider and include a discussion on the feasibility of replacing natural gas fueled engines with commercial electric powered compressors.
6. The four-factor analysis proposes a 2.5 grams per brake horsepower-hour (g/bhp-hr.) NO_X emission rate achievable by Low Emission Controls for Cooper Bessemer engines at the facility. Please provide a vendor quote with cost and control efficiency for Low Emission Controls.

7. Consider and include a discussion of variations of Clean Burn Technology (CBT) used to reduce NO_X emissions that may be less expensive than the full CBT packages proposed. Please include cost and efficiencies in the analysis.
8. Please verify and provide documentation that control systems have not yet been developed for selective catalytic reduction (SCR) controls that can handle variable load engines. This appears to be one main reason that SCR has not been implemented on two-stroke lean burn (2SLB) internal combustion engines in oil and gas midstream operations.
9. Please provide vendor quotes that include the cost information, recommendations, and equipment specifications for the engine control cost estimates.
10. Provide any electronic spreadsheets used for control technology calculations.

Please note, NMED must document the cost and engineering information used to analyze potential control measures. If you feel that your supplemental information should be classified as confidential business information (CBI), it will need to be reviewed and approved as such by NMED and EPA. Submit CBI with the word 'confidential' included in the electronic file name and on each page of the document. Do not combine non-confidential business information and CBI in the same files. Also, the claimant must satisfy the conditions in 20.2.1.115.B(3)(a)-(d) NMAC when the CBI is submitted. Until NMED and EPA determines if the information qualifies as CBI, the information will not be disclosed to anyone other than those listed in 20.2.1.115 NMAC.

NMED respectfully requests that your company submit the additional information on four-factor analysis electronically as soon as possible to Kerwin Singleton and Mark Jones. Please contact NMED if you have questions about the additional information request. We encourage your questions in order to help expedite the technical analysis required under the Regional Haze Program. Staff would be happy to meet with you in person to discuss these requirements in more detail. Likewise, staff may further contact you with questions or require additional information during its review of your submittals.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact me at (505) 476-4350, kerwin.singleton@state.nm.us, or Mark Jones at (505) 566-9746, mark.jones@state.nm.us.

Sincerely,

Kerwin Singleton
Planning Section Chief

NMED Final Cost Evaluation
Transwestern Pipeline Company - Roswell Compressor Station No. 9

Facility Information

TWP - Roswell Compressor Station No. 9	**Facility**
Two 4SLB 4,500-hp RICE	**Units**
903 and 904	**Unit IDs**
LEC	**Evaluated Pollution Control**
2.5	**Post-control Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
4500	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 903	Unit 904	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Detailed cost estimate includes all equipment, controls upgrade, labor, engineering, installation, contingency, comissioning and post commissioning support. Estimate is "based on a current quote from Cooper for the LEC upgrades, and previous project estimates prepared for the gearbox replacemenet (adjusted for inflation to current dollars)."
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ -	$ -	-	
Additional Capital ($)	AC	$ -	$ -	-	
Total Capital Investment ($)	TCI	$ 5,024,250	$ 5,024,250	TWP 8.11.23 update	
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	TWP used prime rate as of 7.11.23 (8%) in its 8.11.23 update
Useful Life (yr)	Y	20	20	TWP 8.11.23 update	
Capital Recovery Factor	CRF	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 492,840	$ 492,840	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	-	Incremental O&M of a LEC retrofit is expected to be negligible
Other Indirect Annual Costs ($/yr)	OAC	$ 200,970	$ 200,970	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 693,810	$ 693,810	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	78%	55%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	463.7	210.0	CY 2023 emissions testing and average operating hours (2019-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by TWP
Projected Actual Emissions (ton/yr)	PAE	463.7	210.0	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	360.3	115.0	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 1,925**	**$ 6,032**	-	TAC/ER
Price Index	PI	1.00	1.00	-	CEPCI 2024* / CEPCI 2023 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 1,925**	**$ 6,032**	-	CE1 x PI

NMED Final Cost Evaluation
Transwestern Pipeline Company - Roswell Compressor Station No. 9

Facility Information

TWP - Roswell Compressor Station No. 9	**Facility**
Two 4SLB 4,500-hp RICE	**Units**
903 and 904	**Unit IDs**
SCR	**Evaluated Pollution Control**
80%	**SCR Control efficiency**
38.17	**Heat Input Capacity (MMBtu/hr/unit)**

Supporting Information

2024	**Calendar year associated with cost estimates**
4500	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 903	Unit 904	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	-	Not specified by TWP
Total Capital Investment ($)	TCI	$ 2,354,033	$ 2,425,885	EPA SCR Tool (2024$)	
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	TWP used prime rate as of 7.11.23 (8%) in its 8.11.23 update
Useful Life (yr)	Y	20	20	EPA Cost Manual	
Capital Recovery Factor	CRF	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 230,912	$ 237,960	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 106,048	$ 65,545	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 2,769	$ 2,774	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 339,730	$ 306,279	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	80%	80%	Initial TWP FFA Submittal	Consistent with EPA and industry documentation
Baseline Actual NOx Emissions (ton/yr)	BAE	463.7	210.0	CY 2023 emissions testing and average operating hours (2019-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by TWP
Projected Actual Emissions (ton/yr)	PAE	463.7	210.0	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	370.9	168.0	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE1**	**$ 916**	**$ 1,823**	-	TAC/ER.

NMED Final Cost Evaluation
Transwestern Pipeline Company - Roswell Compressor Station No. 9

Facility Information

TWP - Roswell Compressor Station No. 9	**Facility**
Two 4SLB 4,500-hp RICE	**Units**
903 and 904	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
29.0	**Post-control Emissions (ton/yr, provided by facility)**

Supporting Information

2023	**Calendar year associated with cost estimates**
4500	**Maximum Power Output Unit (hp/unit)**

Economic Evaluation

Cost Component		Units 903 & 904	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	Estimate "is based on previously prepared project proposal for an installation of a turbine at Roswell Compressor Station." Estimate includes: 1. Purchase of one (1) Solar Mars 100 turbine driven gas compressor package 2. Foundation pouring and leveling, compressor building, PCR building, station piping, gas cooling 3. Electrical work- conduit/cable install to PCR, VFD, motor, gearbox, control room, etc. 4. Contract and General Labor 5. Required station control system upgrade for new unit
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ -	-	
Additional Capital ($)	AC	$ -	-	
Total Capital Investment ($)	TCI	$ 32,100,000	TWP 8.11.23 update	
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	TWP used prime rate as of 7.11.23 (8%) in its 8.11.23 update
Useful Life (yr)	Y	30	ERG experience based on discussions with CT manufacturers	TWP indicated 25 years
Capital Recovery Factor	CRF	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 2,717,947	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ (486,860)	Net change in O&M costs	OM1 - OM2
New turbine O&M ($/yr)	OM1	$ 140,140	TWP 8.11.23 update	Based on TWP similar facility costs (2022$). Adjusted to 2023$ using CEPCI index of 0.98 (CEPCI 2023 (797.9)/ CEPCI 2022 (816.0))
Existing RICE O&M ($/yr)	OM2	$ 627,000	TWP 8.11.23 update	Based on facility information
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 2,231,087	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	96%	-	ER/BAE
Baseline Actual NOx Emissions (ton/yr)	BAE	673.7	CY 2023 emissions testing and average operating hours (2019-2021)	Sum of units 903 & 904 BAE
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by TWP
Projected Actual Emissions (ton/yr)	PAE	673.7	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	644.6	-	BAE-Post Control Emission Rate (provided by TWP)
2023$ Cost Effectiveness ($/ton)	**CE**	**$ 3,461**	-	TAC/ER
Price Index	PI	1.00	-	CEPCI 2024* / CEPCI 2023 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 3,461**	-	CE1 x PI

NMED Final Cost Evaluation
Transwestern Pipeline Company - Roswell Compressor Station No. 9

Facility Information

TWP - Roswell Compressor Station No. 9	**Facility**
Two 4SLB 4,500-hp RICE	**Units**
903 and 904	**Unit IDs**
Replacement with EMD	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
4500	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		All Units	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	TCC estimate from TWP includes costs related to purchased equipment, equipment upgrades, building and infrastructure modifications, contingency and labor.
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ 30,700,000	TWP 8.11.23 update	
Additional Capital ($)	AC	$ 10,272,800	Estimated	Assumes no line upgrade costs since TWP did not specify they were necessary. New substation cost estimated using $20M Harvest estimate and adjusted using power rating (9000 vs. 17522 hp).
Total Capital Investment ($)	TCI	$ 40,972,800	-	TCC + AC
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	TWP used prime rate as of 7.11.23 (8%) in its 8.11.23 update
Useful Life (yr)	Y	25	TWP 8.11.23 update	
Capital Recovery Factor	CRF	0.0897	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 3,675,697	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 2,596,864	-	OC + AOM + AFC
Other ($/yr)	OC	$ 3,800,000	TWP 8.11.23 update	
Associated non-electricity O&M ($/yr)	AOM			
Annual Fuel Credit ($/yr)	AFC	$ (1,203,136)	3/25/21 email from TWP	Scaled to account for projected operation and converted to 2023$ using CEPCI
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 6,272,562	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	673.7	CY 2023 emissions testing and average operating hours (2019-2021)	Sum of BAE of units 903 & 904
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by TWP
Projected Actual Emissions (ton/yr)	PAE	673.7	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	673.7	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE**	**$ 9,311**	-	TAC/ER
Price Index	PI	1.00	-	CEPCI 2024* / CEPCI 2023 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 9,311**	-	CE1 x PI

NMED Final Cost Evaluation
Transwestern Pipeline Company - Roswell Compressor Station No. 9

Unit 903: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	34.43	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	278,211,765	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3620	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	3.233	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.6466	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 903: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	34	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	292,538,118	scf/Year	
Actual Annual fuel consumption (Mactual) =		278,211,765	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.951	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8331	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	89.05	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	370.93	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.14		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.9	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	267.70	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	35	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	119	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	16	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	5,400	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	20.38	kW

Unit 903: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,354,033	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$106,048 in 2024 dollars
Indirect Annual Costs (IDAC) =	$233,700 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$339,748 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$11,770 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$70,254 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$16,981 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$7,042 in 2024 dollars
Direct Annual Cost =		$106,048 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,769 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$230,931 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$233,700 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$339,748 per year in 2024 dollars
NOx Removed =	371 tons/year
Cost Effectiveness =	$916 per ton of NOx removed in 2024 dollars

NMED Final Cost Evaluation
Transwestern Pipeline Company - Roswell Compressor Station No. 9

Unit 904: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	36.06	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	267,984,210	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3620	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	1.521	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.3041	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			
Number of SCR reactor chambers (n_{scr})	1			
Number of catalyst layers (R_{layer})	3			
Number of empty catalyst layers (R_{empty})	1			
Ammonia Slip (Slip) provided by vendor	2	ppm		
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet		
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm		
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours		
Estimated SCR equipment life	20	Years*		
Gas temperature at the SCR inlet (T)	650	°F		
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour		
Concentration of reagent as stored (C_{stored})	29	percent*		
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*		
Number of days reagent is stored ($t_{storage}$)	14	days		

* For industrial boilers, the typical equipment life is between 20 and 25 years.

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 904: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	36	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	306,387,585	scf/Year	
Actual Annual fuel consumption (Mactual) =		267,984,210	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.875	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7662	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	43.86	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	168.04	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.14		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.9	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	198.86	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	17	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	59	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,700	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	21.35	kW

Unit 904: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,425,885	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$65,545 in 2024 dollars
Indirect Annual Costs (IDAC) =	$240,753 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$306,298 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,129 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$31,827 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$16,357 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$5,231 in 2024 dollars
Direct Annual Cost =		$65,545 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,774 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$237,979 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$240,753 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$306,298 per year in 2024 dollars
NOx Removed =	168 tons/year
Cost Effectiveness =	$1,823 per ton of NOx removed in 2024 dollars

October 30, 2019 Reference No. 11203587

Mark Jones
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505

Dear Mr. Jones:

Re: Four Factor Analysis
Roswell Compressor Station
Transwestern Pipeline Company, LLC

GHD Services, Inc. (GHD) is submitting, on behalf of Transwestern Pipeline Company, LLC., a four-factor analysis of the Roswell Compressor Station to the New Mexico Environment Department (NMED). This report is for the NMED Regional Haze Second Planning Period Progress Analysis under the Clean Air Act (CAA) and Regional Haze Rule (40 CFR §51.300 to 51.309).

If you have any questions or concerns, please contact myself at (720) 974-0937 or Larry Campbell at (575) 625-8022.

Sincerely,

GHD

Sergio Guerra
Project Manager

SG/PH/1

Encl. Four-Factor Analysis

cc: Larry Campbell – Transwestern Pipeline Company, LLC.

GHD
14998 West 6th Avenue Suite 800 Golden Colorado 80401 USA
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REGISTERED COMPANY FOR ISO 9001 ENGINEERING DESIGN



Four-Factor Analysis for Regional Haze Planning in New Mexico

Roswell Compressor Station No. 9
Chaves County, New Mexico
Title V Operating Permit No. P154-R3M1
NSR Permit No. 6742
AIRS No. 35-005-0008

Transwestern Pipeline Company, LLC









14998 West 6th Avenue Suite 800 80401 Golden Colorado USA | 11203587 | October 2019

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Appendix A RICE Engine Baseline Emissions, Reductions, and Control Cost Analysis

Appendix B Roswell Compressor Station Title V Operating Permit

List of Acronyms

AFGD ..... Advanced Flue Gas Desulfurization
APCD ..... Air Pollution Control Division
BART ..... Best Available Retrofit Technology
CAA ..... Clean Air Act
CAIR ..... Clean Air Interstate Rule
CaSO3 ..... Calcium sulfite
CaSO4 ..... Calcium sulfate
CO ..... Carbon Monoxide
CO2 ..... Carbon Dioxide
CPI ..... Consumer Price Index
DEP ..... Department of Environmental Protection
DEQ ..... Department of Environmental Quality
DNR ..... Department of Natural Resources
DSI ..... Dry Sorbent Injection
EIA ..... Energy Information Administration
EPA ..... Environmental Protection Agency
FGD ..... Flue Gas Desulfurization
FGR ..... Flue Gas Recirculation
ICI ..... Industrial, Commercial, Institutional
HEIS ..... High Energy Ignition Systems
LADCO ..... Lake Michigan Air Directors Consortium
LNB ..... Low NOx Burners
MACT ..... Most Achievable Control Technology
MARAMA ..... Mid-Atlantic Regional Air Management Association
N2 ..... Nitrogen gas
NCASI ..... National Council for Air and Stream Improvement
NESCAUM ..... Northeast States for Coordinated Air Use Management
NESHAP ..... National Emission Standards for Hazardous Air Pollutants
NH3 ..... Ammonia
NOx ..... Nitrogen Oxides
NSCR ..... Non-Selective Catalytic Reduction
NSPS ..... New Source Performance Standards
OFA ..... Over-Fired Air
PM ..... Particulate Matter
RICE ..... Reciprocating Internal Combustion Engine
RSCR ..... Regenerative Selective Catalytic Reduction
SCR ..... Selective Catalytic Reduction
SD ..... Spray Dry
SIP ..... State Implementation Plan
SNCR ..... Selective Non-Catalytic Reduction
SO2 ..... Sulfur Dioxide
SSM ..... Startup, Shutdown, Maintenance
ULNB ..... Ultra Low NOx Burners
WRAP ..... Western Regional Air Partnership
VOC ..... Volatile Organic Compound

1. Executive Summary

In response to the New Mexico Environment Department (NMED) letter dated July 18, 2019, GHD Services, Inc. (GHD) was retained by ETC Texas Pipeline, LTD, the parent company of Transwestern Pipeline Company, LLC, to prepare a four-factor analysis for the NMED Regional Haze Second Planning Period Progress Analysis under the Clean Air Act (CAA) and Regional Haze Rule (40 CFR §51.300 to 51.309). As a part of this Progress Analysis, NO_x and SO_2 emissions were evaluated at the Roswell Compressor Station (Roswell CS).

The four-factor analysis is codified in 40 CFR §51.308(d)(1)(i)(A) and is designated as a means for establishing reasonable progress goals towards achieving natural visibility conditions. The four factors to consider are:

1. The costs of compliance
2. The time necessary for compliance
3. The energy and non-air quality environmental impacts of compliance
4. The remaining useful life of any potentially affected sources

The purpose of the four-factor analysis is to identify control measures for reducing emissions that could be used to establish the long-term strategy for attaining the states visibility goals. The NMED has requested that evaluations be completed for individual equipment that have a potential to emit (PTE) greater than ten pounds per hour of NO_x or SO_2. The source categories identified at Roswell CS for evaluation are two existing compressor engines (Units 903 and 904). NMED also instructed to use actual emissions from reporting year 2016 as a baseline to calculate emission reductions for control options evaluated. However, permitted hourly NO_x emission rates were used for Unit 904 in this analysis due to the 2016 emissions inventory showing lower NO_x emission rates than what was feasible to obtain by the engine vendor. The cost range for emission reductions reflects the range of operation time in 2016 between the two RICE compressor engines analyzed. The results of the subsequent four-factor analysis are in Table 1.1 below.

Table 1.1 Summary of Roswell CS Four Factor Analysis Results

Source Category	Regional Haze Pollutant and Control Option Analyzed	Average Cost in 2019 Dollars (dollars per ton of pollutant reduction)	Compliance Timeframe	Energy & Non-Air Quality Impacts	Remaining Useful Life
RICE Engines	NO_x; Low Emission Controls (LEC)	$7,000 - $15,300	2-5 Years	None known for LEC	25 years for controls; Indefinite for RICE engines
	NO_x; Selective Catalytic Reduction (SCR)	$4,300- $5,500	2-5 Years	Storage and handling of hazardous materials	25 years for controls; Indefinite for RICE engines

2. Source Category Analysis for RICE Engines

2.1 Source Category Description

Roswell CS operates two (2) Reciprocating Internal Combustion Engines (RICE) that are subject to the requirements of the four-factor analysis. Both engines are 4,500-hp natural gas-fired Cooper-Bessemer LSV-16G compressor engines (Units 903 and 904) used for transportation of natural gas. Roswell CS operates two (2) electric-driven compressor engines that do not have associated emissions. Roswell CS also operates one (1) 408-hp natural gas-fired Ingersoll-Rand PSVG-6 generator engine that operates less than 100 hours per year and is therefore an exempt source, per NMAC 20.2.72.202.B.3.

2.2 Clean Air Act and State Regulations

The two compressor engines subject to this analysis are subject to the following state and federal regulations:

20.2.61.109 NMAC

This regulation limits opacity to 20% applies to Stationary Combustion Equipment, such as engines, boilers, heaters, and flares unless your equipment is subject to another state regulation that limits particulate matter such as 20.2.19 NMAC (see 20.2.61.109 NMAC). Units 903 and 904 are subject to this regulation.

20.2.82 NMAC

The listed units are subject to MACT standards. Roswell CS's engines (Units 903, 904) are subject to 40 CFR Part 63, Subpart ZZZZ and are therefore subject to this regulation.

MACT 40 CFR 63, Subpart ZZZZ

The station is a major source of hazardous air pollutant (HAP) emissions; therefore, this rule applies to the engines located at the station. Engines 903 and 904 are existing 4SLB engines of greater than 500 horsepower (hp). Per §63.6590(b)(3)(ii), these engines are subject to the regulation, but do not have any requirements under Subpart ZZZZ.

2.3 NO_x Emissions and Control Options

NO_x is generated from the combustion of natural gas used to power the applicable compressor engines. The exhaust gases are released to the atmosphere through stacks associated with each engine.

There are several categories of NO_x formation in combustion processes. The combustion process taking place in RICE predominantly produces thermal NO_x[1] which is formed when nitrogen and oxygen unite during high temperature and high pressure combustion.[2]

While neither engine currently utilizes NO_x emission controls, two control options were assessed for the applicable engines: Low Emission Controls (LEC) and Selective Catalytic Reduction (SCR).

2.3.1 Low Emission Controls (LEC)

LEC is a combination of combustion controls in which various engine modifications, upgrades, and tuning methods provide lower emission combustion.

One upgrade includes increasing the air-to-fuel ratio (AFR) to reduce thermal NO_x formation by diluting combustion gases and lowering peak flame temperature. Upgrades to the AFR controller and turbocharger would be required. Adjusting ignition timing is another modification associated with LEC. This control delays ignition in the power stroke when the chamber is below its maximum pressure. This causes ignition at a lower temperature, thus lowering thermal NO_x formation during combustion. Other LEC options include installing cylinder heads fitted with pre-combustion chambers, larger intercooling applications, enhanced mixing, bypass valves, and increased ignition energy.[3]

A quotation provided by Cooper Machinery Services shows that these LEC upgrades can lower NO_x emission rates to 2.5 g/hp-hr.[10]

2.3.2 Selective Catalytic Reduction (SCR)

SCR is a post-combustion control for lean-burn combustion in which ammonia or urea is mixed with exhaust gases over a catalyst to (ideally) convert NO_x to nitrogen gas (N_2) and water (H_2O). While SCR has been applied to large boilers and turbines in the power generation industry, its application on new RICE in the gas transmission industry has been rare, and retrofitted applications for existing lean burn RICE had not occurred as of 2014.[4]

There are several factors that make SCR difficult for this application. Technical concerns, such as reagent injection control, exhaust temperature requirements, and variations in the exhaust NO/NO_2 ratio, pose limitations on the effectiveness and feasibility of SCR. NOx reduction may not be achieved, or even more ammonium sulfates may be emitted if the reagent feed rate and/or operating temperature is not precisely tuned to the fluctuating exhaust properties.[4]

Another challenge is that combustion byproducts and engine oil carryover often contaminate the catalytic elements in SCR applications. Routine cleaning and replacement as well as greater management are required for effective use.[4]

For these reasons, LEC is the preferred control method.

Table 2.1 below summarizes the control technology options:

Table 2.1 Summary of Potential No_x Control Options

Technology	Description	Applicability	Feasibility	Performance (% reduction)
Low Emission Combustion (LEC)	Engine tuning improvements to increase combustion efficiency.	Potentially applicable to Units 903 and 904	Potentially feasible	33-80%
Selective Catalytic Reduction (SCR)	Exhaust control that converts NO_x to nitrogen and water using ammonia or urea.	Not applicable based on documented difficulty implementing technology on RICE engines	Not feasible based on documented difficulty implementing technology on RICE engines	70-90%[5]

2.3.3 Four Factor Analysis of Potential NO_x Control Options

2.3.3.1 Factor 1: Cost of Compliance

A quotation was provided by Cooper Machinery Services[10] which outlined the proposed LEC upgrades to Units 903 and 904. Modifications include:

- Installing new cylinder heads fitted with pre-combustion chambers;
- Replacing existing water-cooled pulse exhaust manifold with a dry constant pressure exhaust manifold;
- Adding turbocharger bypass valves to exhaust manifold;
- Upgrading turbocharger to increase air-to-fuel ratio;
- Replacing current intercoolers with larger intercoolers; and
- Adding pilot fuel lines and pressure control for pre-combustion chamber fuel.

Cost effectiveness estimates from these LEC upgrades range from $7,000 - $15,300 per ton of NO_x removed. See Appendix A for cost estimate calculations.

The capital costs for SCR, if one were to assume this was an 'achievable technology' for this application, are varied. There are a number of published cost estimates for typical coal- oil- and gas-fired medium to large sized boilers. The same cannot be said for a retrofit of a natural gas-fired compressor engine. In addition, the cost to retrofit and engine with SCR is much higher than an

original SCR installation, which would apply to this analysis. SCR systems used to retrofit an existing unit increase costs by 30%.[5] O&M costs may also be substantial depending on reagent usage, catalyst replacement, and increased electrical usage. The cost effectiveness of SCR was estimated from $4,300- $5,500 per ton removed.

See Appendix A for emission reductions and cost calculations.

Table 2.2 Summary of Cost Effectiveness of Potential No_x Control Options

Control Option	Specific Design Parameters	Cost Effectiveness (2019 $/ton)	Factors Affecting Cost	Potential Applicability to Specific Affected Units
Low Emissions Controls (LEC)	Power cylinder heads, upgraded water coolers, high efficiency turbocharger, and miscellaneous on-engine assemblies.	$7,000 - $15,300	Annual hours of operation, target NO_x emission factor	Potentially applicable to units 903 and 904
Selective Catalytic Reduction (SCR)	Exhaust control that converts NO_x to nitrogen and water using ammonia or urea.	$4,300- $5,500	Contamination from byproducts, excessive routine maintenance, reagent usage	Potentially applicable to units 903 and 904

2.3.3.2 Factor 2: Time Necessary for Compliance

According to NMED guidance, sources are generally given between two and five years to implement changes for compliance with new regulations and implementation of this LEC would fall within that timeframe. Although no specific data was found, it would be reasonable to assume that a two to five year period would also be appropriate for the installation of SCR.

2.3.3.3 Factor 3: Energy and Non-Air Impacts

The LEC technology does not require the handling or storage of hazardous materials and does not require changes that could create an energy demand penalty.

As described above, SCR systems require ammonia (aqueous and/or anhydrous) or urea-to-ammonia reagents. Anhydrous ammonia is considered a hazardous material, and would be subject to storage, transportation, and operational regulations.

2.3.3.4 Factor 4: Remaining Useful Life of the Source

Although engines 903 and 904 were manufactured in 1959, they are planned for continuous operation until they are no longer functional. The estimated service life of the assessed control equipment (LEC and SCR) is 25 years.[6] Based on this information, the control options are

considered the limiting factor for useful life of the source. The cost effectiveness for applying the control options considers this as the minimum lifespan.

3. References

1. U.S Environmental Protection Agency (USEPA). *Technical Support Document for Controlling NOx Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines*. March 2007.
2. U.S Environmental Protection Agency (USEPA). *Nitrogen Oxides (NOx), Why and How They Are Controlled.* November 1999.
3. INGAA Foundation, Inc. *Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOx Control for Natural Gas Transmission and Storage Compressor Drivers*. December 2017.
4. INGAA Foundation, Inc. *Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry.* July 2014.
5. U.S Environmental Protection Agency (USEPA). *EPA Air Pollution Control Technology Fact Sheet for SCR.*
6. U.S Environmental Protection Agency (USEPA). *EPA Air Pollution Control Cost Manual, 6th Edition*, USEPA Research Triangle Park, NC. January 2002.
7. Northeast States for Coordinated Air Use Management (NESCAUM). *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines*. December 2000.
8. U.S Environmental Protection Agency (USEPA). *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*. August 20, 2019.
9. Western Regional Air Partnership (WRAP). *Reasonable Progress Source Identification and Analysis Protocol, WRAP Regional Haze Planning Work Group – Control Measures Subcommittee*. February 2019.
10. Cost estimate from email correspondence with Bob Bailey with Cooper Machinery Services.

Appendices

Appendix A
RICE Engine Baseline Emissions, Reductions, and Control Cost Analysis

Appendix A

RICE Engine Baseline Emissions, Reductions, and Control Cost Analysis
Roswell Compressor Station - Chaves County, New Mexico

2016 EI	**Unit 903**		**LEC**		**SCR**	
Rated HP	4500		Rated HP	4500	Rated HP	4500
2016 Operating Hours	3607		NOx Emission Factor [1] (g/hp-hr)	2.5	NOx Emission Factor (g/hp-hr)	0.37
Test NOx Emission Rate (lb/hr)	37.19		2016 Operating Hours	3607	2016 Operating Hours	3607
NOx emissions (ton/yr)	67.07		New NOx Emission Rate (lb/hr)	24.80	New NOx Emission Rate (lb/hr)	3.72
			NOx Emission Equivalent (ton/yr)	44.73	NOx Emission Equivalent (ton/yr)	6.71
			Difference (tons)	22.34	Difference (tons)	60.36
			% Reduction	**33%**	**% Reduction[2]**	**90%**
			2019 $/ton	**$ 15,308**	**2019 $/ton**	**$ 4,349**

Permitted Rates [3]	**Unit 904**		**LEC**		**SCR**	
Rated HP	4500		Rated HP	4500	Rated HP	4500
2016 Operating Hours	971		NOx Emission Factor [1] (g/hp-hr)	2.5	NOx Emission Factor (g/hp-hr)	1.26
PTE NOx Emission Rate [3] (lb/hr)	125		2016 Operating Hours	971	2016 Operating Hours	971
NOx emissions (ton/yr)	60.69		New NOx Emission Rate (lb/hr)	24.80	New NOx Emission Rate (lb/hr)	12.50
			NOx Emission Equivalent (ton/yr)	12.04	NOx Emission Equivalent (ton/yr)	6.07
			Difference (tons)	48.65	Difference (tons)	54.62
			% Reduction	**80%**	**% Reduction[2]**	**90%**
			2019 $/ton	**$ 7,030**	**2019 $/ton**	**$ 5,483**

[1] Lowest achievable emission factor, per Cooper Machinery quote

[2] SCR Reduction efficiency from *TECHNICAL SUPPORT DOCUMENT FOR CONTROLLING NOx EMISSIONS FROM STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES AND TURBINES,* Illinois Environmental Protection Agency, December 2017

[3] Permitted values used due to 2016 emission inventory showing lower NOx emission factor than Cooper Machinery quote

LEC Cost	
Quote From Cooper Machinery Services - 10/17/19	
LEC Cost Description	**2019 $**
Total Capital Cost	1,800,000
Annual O&M Cost (estimate)	270,000
Total Annual Cost per Year	342,000

*Estimated useful life of LEC: 25 years

*Estimated Annual O&M cost as a percent of the Total Capital Investment: 15 %

SCR Cost				
	Unit 903		Unit 904	
SCR Cost Description	**1994 $**	**2019 $**	**1994 $**	**2019 $**
Total Capital Cost	634,900	1,100,282	634,900	1,100,282
Annual O&M Cost (estimate)	-	218,527	-	255,446
Total Annual Cost per Year	-	262,538	-	299,457

*Cumulative rate of Consumer Price Index (CPI) inflation from 1994 to 2019: 73.3 %

*Estimated useful life of SCR: 25 years

*Estimated Annual O&M cost as a percent of the Total Capital Investment, includes labor and cost of reagent and catalyst replacement: 20 %

Appendix A

RICE Engine Baseline Emissions, Reductions, and Control Cost Analysis
Roswell Compressor Station - Chaves County, New Mexico

Unit 903 SCR Costs			
Total Capital Cost (TCC)			Source
Lean Burn	*TCC = $310,000 + $72.70 * HP*		Pg III-30, NESCAUM, December 2000
Engine HP		4,500	
TCC (1994 dollars) =		$ 637,150.00	
CPI 1994		148.2	
CPI 2019		254.95	
TCC (2019 dollars) =		**$ 1,096,095.77**	
Total Annual Costs (TAC)			Source
Direct Annual Costs			
	Operator Labor Costs		
	Operator labor hours (hrs/day)	4	Sec 2.5, EPA Control Cost Manual
	Operator labor rate ($/hr)	$60	Sec 2.5, EPA Control Cost Manual
	Days of SCR operation (days/yr)	365	
Operator Labor		**$87,600**	
Supervisor	*15% of Operator*	**$13,140**	
	Materials		
	Ammonia ($Ammonia/yr)	**$ 15,355.55**	
	Catalyst ($/replacement catalyst layer)	**$ 12,149.31**	
	Maintenance		
	*Annual Maintenance Cost = 0.005*TCI*	**$ 5,480.48**	Eq. 2.57, EPA Control Cost Manual
Indirect Annual Costs	*Indirect Annual Cost = (Administrative Charges) + (Capitol Recovery)*		Eq. 2.68
Administrative Charges	*Administrative Charges = 0.03*((Operator Labor Cost)+0.4*(Annual Maintenance Cost))*	$ 3,087.97	Eq. 2.69
Capitol Recovery	*Capitol Recovery = CRF * TCI*	$ 81,713.23	Eq. 2.70
Capitol Recovery Factor (CRF)	$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$ n = 25 yrs, i = 5.5%	0.074549353	Eq. 2.71
Indirect Annual Costs		**$ 84,801.20**	
Total Annual Costs (TAC)	*TAC = Direct Annual Costs + Indirect Annual Costs*	**$218,527**	

Appendix A

RICE Engine Baseline Emissions, Reductions, and Control Cost Analysis
Roswell Compressor Station - Chaves County, New Mexico

Unit 903 SCR Reagent and Catalyst Cost Backup Calculations				
			Unit	Source
Selective Catalytic Reduction		90%		
Uncontrolled emissions		37.19	lb/hr	2019 Stack Test
Engine Horsepower		4,500	hp	Permit
Engine Fuel Consumption		7651.00	Btu/hp-hr	2019 Stack Test
Max Heat Input (Q_B)		34.43	MMBTU/hr	Calculated
Stoichiometric Ratio Factor (SRF)		1.05		
Flue Gas Flow Rate ($q_{fluegas}$)		23514.79	acfm	2019 Stack Test
dscfm		8790.27	dscfm	2019 Stack Test
CF_plant		1		
Nox Removal Efficiency (η_{NOx})		90%		
N_{SCR}	*Number of SCRs*	1		
Catalyst Volume ($Vol_{catalyst}$)	$2.81*Q_B*\eta_{adj}*slip_{adj}*Nox_{adj}*S_{adj}*T_{adj}/N_{SCR}$	448.73	ft^3	Eq. 2.22, EPA Control Cost Manual
η_{adj}	$(0.2869+(1.058+\eta_{NOx}))$	2.24		Eq. 2.23, EPA Control Cost Manual
Slip	$(SRF-\eta_{NOx})$	0.15		
$Slip_{adj}$	*1.2835-(0.0567*slip)*	1.27		Eq. 2.24, EPA Control Cost Manual
NOx_{in}	*Uncontrolled emissions / Q_B*	1.08	lb/MMBTU	Calculated
NOx_{adj}	$0.8524+(0.3208*NOx_{in})$	1.20		Eq. 2.25, EPA Control Cost Manual
S, Sulfur in fuel		0.01		Section 2.5, EPA Control Cost Manual
S_{adj}	*0.9636+(0.0455*S)*	0.96		Eq. 2.26, EPA Control Cost Manual
SCR inlet temp		600	F	
SCR inlet temp		588.7	K	
T_{adj} for inlet T not - 700 F	*15.16-(0.03937*T)+(2.74E-5*T^2)*	1.402		Eq. 2.27, EPA Control Cost Manual
$A_{catalyst}$	$(q_{fluegas}/(16*60)$	24.49	ft^2	Eq. 2.28, EPA Control Cost Manual
n_{layer}	$V_{catalyst}/(h_{layer}*A_{catalyst})$	5.91		Eq. 2.31, EPA Control Cost Manual
h_{layer}		4.1	ft	Eq. 2.32, EPA Control Cost Manual
h'_{layer}		3.1	ft	
$m_{reagent}$	$NOx_{in}*Q_B*\eta_{NOx}*SRF*MW_{reagent}/(MW_{NOx})$	12.99	lb/hr	Eq. 2.35, EPA Control Cost Manual
$MW_{reagent}$	*MW of ammonia*	17		
MW_{NOx}	*MW of NOx*	46		
C_{sol}	*Concentration of ammonia in aqueous solution*	0.29		Section 2.5, EPA Control Cost Manual
m_{sol}	$m_{reagent}/C_{sol}$	44.79	lb/hr	Eq. 2.36, EPA Control Cost Manual
ρ_{sol}		56	lb/ft^3	
v_{sol}		7.4805	gal/ft^3	
q_{sol}	$(m_{soi}/\rho_{sol})*7.4805$	5.98	gal/hr	Eq. 2.37, EPA Control Cost Manual
t_{op}		8760	hrs	
Vol_{tank}	$Voltank = q_{sol}*t_{op}$	52408.02	gallons	Eq. 2.38, EPA Control Cost Manual
cost of reagent		0.293	$/gallon	
Cost of reagent (per hour)		1.75	$/hr of ammonia	
Cost of reagent (per year)		**$ 15,355.55**	$/yr of ammonia	
Catalyst Cost (CC)		$ 160.00	$/ft^3	
Catalyst cost Replacement	$N_{SCR}*Vol_{catalyst}*(CC/n_{layer})$	**$ 12,149.31**	$/replacement layer/year	Eq. 2.63, EPA Control Cost Manual

Appendix A

RICE Engine Baseline Emissions, Reductions, and Control Cost Analysis
Roswell Compressor Station - Chaves County, New Mexico

Unit 904 SCR Costs			
Total Capitol Costs (TCC)			Source
Lean Burn	*TCC = $310,000 + $72.70 * HP*		Pg III-30, NESCAUM, December 2000
Engine HP		4,500	
TCC (1994 dollars) =		$ 637,150.00	
CPI 1994		148.2	
CPI 2019		254.95	
TCC (2019 dollars) =		**$ 1,096,095.77**	
Total Annual Costs (TAC)			Source
Direct Annual Costs			
	Operator Labor Costs		
	Operator labor hours (hrs/day)	4	Sec 2.5, EPA Control Cost Manual
	Operator labor rate ($/hr)	$60	Sec 2.5, EPA Control Cost Manual
	Days of SCR operation (days/yr)	365	
Operator Labor		**$87,600**	
Supervisor	*15% of Operator*	**$13,140**	
	Materials		
	Ammonia ($Ammonia/yr)	**$ 51,611.83**	
	Catalyst ($/replacement catalyst layer)	**$ 12,812.30**	
	Maintenance		
	*Annual Maintenance Cost = 0.005*TCI*	**$ 5,480.48**	Eq. 2.57, EPA Control Cost Manual
Indirect Annual Costs	*Indirect Annual Cost = (Administrative Charges) + (Capitol Recovery)*		Eq. 2.68
Administrative Charges	*Administrative Charges = 0.03*((Operator Labor Cost)+0.4*(Annual Maintenance Cost))*	$ 3,087.97	Eq. 2.69
Capitol Recovery	*Capitol Recovery = CRF * TCI*	$ 81,713.23	Eq. 2.70
Capitol Recovery Factor (CRF)	$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$ n = 25 yrs, i = 5.5%	0.074549353	Eq. 2.71
Indirect Annual Costs		**$ 84,801.20**	
Total Annual Costs (TAC)	*TAC = Direct Annual Costs + Indirect Annual Costs*	**$255,446**	

Unit 904 SCR Reagent and Catalyst Costs Backup Calculations				
			Unit	Source
Selective Catalytic Reduction		90%		
Uncontrolled emissions		125.00	lb/hr	2019 Stack Test
Engine Horsepower		4,500	hp	Permit
Engine Fuel Consumption		8014.00	Btu/hp-hr	2019 Stack Test
Max Heat Input (Q_B)		36.06	MMBTU/hr	Calculated
Stoichiometric Ratio Factor (SRF)		1.05		
Flue Gas Flow Rate ($q_{fluegas}$)		24798.00	acfm	2019 Stack Test
dscfm		9424.02	dscfm	2019 Stack Test
CF_plant		1		
Nox Removal Efficiency (η_{NOx})		90%		
N_{SCR}	*Number of SCRs*	1		
Catalyst Volume ($Vol_{catalyst}$)	$2.81*Q_B*\eta_{adj}*slip_{adj}*Nox_{adj}*S_{adj}*T_{adj}/N_{SCR}$	770.09	ft^3	Eq. 2.22, EPA Control Cost Manual
η_{adj}	$(0.2869+(1.058+\eta_{NOx}))$	2.24		Eq. 2.23, EPA Control Cost Manual
Slip	$(SRF-\eta_{NOx})$	0.15		
$Slip_{adj}$	*1.2835-(0.0567*slip)*	1.27		Eq. 2.24, EPA Control Cost Manual
NOx_{in}	*Uncontrolled emissions / Q_B*	3.47	lb/MMBTU	Calculated
NOx_{adj}	$0.8524+(0.3208*NOx_{in})$	1.96		Eq. 2.25, EPA Control Cost Manual
S, Sulfur in fuel		0.01		Section 2.5, EPA Control Cost Manual
S_{adj}	*0.9636+(0.0455*S)*	0.96		Eq. 2.26, EPA Control Cost Manual
SCR inlet temp		600	F	
SCR inlet temp		588.7	K	
T_{adj} for inlet T not - 700 F	*15.16-(0.03937*T)+(2.74E-5*T^2)*	1.402		Eq. 2.27, EPA Control Cost Manual
$A_{catalyst}$	$(q_{fluegas}/(16*60)$	25.83	ft^2	Eq. 2.28, EPA Control Cost Manual
n_{layer}	$V_{catalyst}/(h_{layer}*A_{catalyst})$	9.62		Eq. 2.31, EPA Control Cost Manual
h_{layer}		4.1	ft	Eq. 2.32, EPA Control Cost Manual
h'_{layer}		3.1	ft	
$m_{reagent}$	$NOx_{in}*Q_B*\eta_{NOx}*SRF*MW_{reagent}/(MW_{NOx})$	43.65	lb/hr	Eq. 2.35, EPA Control Cost Manual
$MW_{reagent}$	*MW of ammonia*	17		
MW_{NOx}	*MW of NOx*	46		
C_{sol}	*Concentration of ammonia in aqueous solution*	0.29		Section 2.5, EPA Control Cost Manual
m_{sol}	$m_{reagent}/C_{sol}$	150.53	lb/hr	Eq. 2.36, EPA Control Cost Manual
ρ_{sol}		56	lb/ft^3	
v_{sol}		7.4805	gal/ft^3	
q_{sol}	$(m_{sol}/\rho_{sol})*7.4805$	20.11	gal/hr	Eq. 2.37, EPA Control Cost Manual
t_{op}		8760	hrs	
Vol_{tank}	$Voltank = q_{sol}*t_{op}$	176149.58	gallons	Eq. 2.38, EPA Control Cost Manual
cost of reagent		0.293	$/gallon	
Cost of reagent (per hour)		5.89	$/hr of ammonia	
Cost of reagent (per year)		**$ 51,611.83**	$/yr of ammonia	
Catalyst Cost (CC)		$ 160.00	$/ft^3	
Catalyst cost Replacement	$N_{SCR}*Vol_{catalyst}*(CC/n_{layer})$	**$ 12,812.30**	$/replacement layer/year	Eq. 2.63, EPA Control Cost Manual

Appendix B
Roswell Compressor Station Title V Operating Permit

NEW MEXICO
ENVIRONMENT DEPARTMENT

525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505-1816
Phone (505) 476-4300
Fax (505) 476-4375
www.env.nm.gov

SUSANA MARTINEZ
GOVERNOR

JOHN A. SANCHEZ
LT. GOVERNOR

BUTCH TONGATE
CABINET SECRETARY

Air Quality Bureau
TITLE V OPERATING PERMIT
Issued under 20.2.70 NMAC

Certified Mail No: 7018 0040 0000 1909 7851
Return Receipt Requested

Operating Permit No:	P154-R4
Facility Name:	Roswell Compressor Station No9
Permittee Name:	Transwestern Pipeline Company
Mailing Address:	6381 North Main Street Roswell, NM 88201
TEMPO/IDEA ID No:	10 - PRT20170001
AIRS No:	35-005-0008
Permitting Action:	Renewal
Source Classification:	Title V Major and PSD Major
Facility Location:	544,900 m E by 3,707,500 m N; Zone 13; Datum NAD 83
County:	Chaves
Air Quality Bureau Contact:	Joseph H. Mashburn
Main AQB Phone No.	(505) 476-4300
TV Permit Expiration Date:	SEP 2 8 2023
TV Renewal Application Due:	SEP 2 8 2022

GBKuehn — SEP 2 8 2018

Liz Bisbey-Kuehn
Bureau Chief
Air Quality Bureau

Date

NEW MEXICO
ENVIRONMENT DEPARTMENT

525 Camino de los Marquez, Suite 1
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SUSANA MARTINEZ
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LT. GOVERNOR

BUTCH TONGATE
CABINET SECRETARY

Air Quality Bureau
TITLE V OPERATING PERMIT
Issued under 20.2.70 NMAC

Certified Mail No: 7018 0040 0000 1909 7851
Return Receipt Requested

Operating Permit No:	P154-R4
Facility Name:	Roswell Compressor Station No9
Permittee Name:	Transwestern Pipeline Company
Mailing Address:	6381 North Main Street Roswell, NM 88201
TEMPO/IDEA ID No:	10 - PRT20170001
AIRS No:	35-005-0008
Permitting Action:	Renewal
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County:	Chaves
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Main AQB Phone No.	(505) 476-4300
TV Permit Expiration Date:	September 28, 2023
TV Renewal Application Due:	September 28, 2022

September 28, 2018

Liz Bisbey-Kuehn — **Date**
Bureau Chief
Air Quality Bureau

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PART A FACILITY SPECIFIC REQUIREMENTS

A100 Introduction

A. Not Applicable

A101 Permit Duration (expiration)

A. The term of this permit is five (5) years. It will expire five years from the date of issuance. Application for renewal of this permit is due twelve (12) months prior to the date of expiration. (20.2.70.300.B.2 and 302.B NMAC)

B. If a timely and complete application for a permit renewal is submitted, consistent with 20.2.70.300 NMAC, but the Department has failed to issue or disapprove the renewal permit before the end of the term of the previous permit, then the permit shall not expire and all the terms and conditions of the permit shall remain in effect until the renewal permit has been issued or disapproved. (20.2.70.400.D NMAC).

A102 Facility: Description

A. This facility is a natural gas compressor station, providing compression of natural gas along a pipeline that transports the gas from production and processing areas to end users.

B. This facility is located approximately 5 miles north of Roswell, New Mexico in Chaves County. (20.2.70.302.A(7) NMAC)

C. This renewal consists of the following. The description of this renewal is for informational purposes only and is not enforceable:

- This Title V renewal incorporates the following equipment listed within NSR Permit 6742, issued May 27, 2016, into operating permit P154-R4: Two MIST extractors (MIST-1 and MIST-2) and six condensate tanks TK-1, TK-30, TK-31, TK-32, TK-33, and TK-34.
- This permit's allowable hourly NOx emission limits for Units 903, 904, and 921 are returned to those modeled for the 2009 Title V permit.
- The allowable annual operating hours for Units 903 and 904 are increased from the previous combined 13,248 total hours of operation per year to 8,760 hours of operation per year per engine.
- The allowable annual operating hours for Unit 921 is increased from 2,680 to 4,500 hours.

D. Tables 102.A and Table 102.B show the potential to emit (PTE) from this facility for information only. This is not an enforceable condition and excludes insignificant or trivial activities.

Table 102.A: Total Potential to Emit (PTE) from Entire Facility

Pollutant	Emissions (tons per year)
Nitrogen Oxides (NOx)	1,122.5
Carbon Monoxide (CO)	160.3
Volatile Organic Compounds (VOC) *	116.5
Sulfur Dioxide (SO_2)	0.8
Total Suspended Particulates (TSP)	4.0
Particulate Matter 10 microns or less (PM_{10})	4.0
Particulate Matter 2.5 microns or less ($PM_{2.5}$)	4.0
Greenhouse Gas (GHG) as CO_2e	72,123

* VOC total includes emissions from Fugitives, SSM and Malfunctions

Table 102.B: Total Potential to Emit (PTE) for *Hazardous Air Pollutants (HAPs) that exceed 1.0 ton per year

Pollutant	Emissions (tons per year)
Acetaldehyde	3.2
Acrolein	2.0
Formaldehyde	19.9
Total HAPs**	27.7

* HAP emissions are already included in the VOC emission total.

** The total HAP emissions may not agree with the sum of individual HAPs because only individual HAPs greater than 1.0 tons per year are listed here.

A103 Facility: Applicable Regulations and Non-Applicable Regulations

A. The permittee shall comply with all applicable sections of the requirements listed in Table 103.A.

Table 103.A: Applicable Requirements

Applicable Requirements	Federally Enforceable	Unit No.
NSR Permit No: **1776M1 & 1777M1** (Per 20.2.72 NMAC)	X	SVE-1 and SVE-2
NSR Permit No: **6742** (Per 20.2.72 NMAC)	X	MIST-1 MIST-2; TK-1, TK-30, TK-31, TK-32, TK-33 and TK-34
20.2.1 NMAC General Provisions	X	Entire Facility
20.2.7 NMAC Excess Emissions	X	Entire Facility

Table 103.A: Applicable Requirements

Applicable Requirements	Federally Enforceable	Unit No.
20.2.61 NMAC Smoke and Visible Emissions	X	903, 904, 921, SVE-1 and SVE-2
20.2.70 NMAC Operating Permits	X	Entire Facility
20.2.71 NMAC Operating Permit Emission Fees	X	Entire Facility
20.2.72 NMAC Construction Permit	X	Entire Facility
20.2.73 NMAC Notice of Intent and Emissions Inventory Requirements	X	Entire Facility
20.2.74 NMAC Permits – Prevention of Significant Deterioration (PSD)	X	Entire Facility
20.2.82 NMAC MACT Standards for Source Categories of HAPS	X	921
40 CFR 50 National Ambient Air Quality Standards	X	Entire Facility
40 CFR 63, Subpart A, General Provisions	X	921
40 CFR 63, Subpart ZZZZ	X	921
40 CFR 63, Subpart GGGGG, Site Remediation	X	SVE-1 and SVE-2

B. Table 103.B lists requirements that are **not** applicable to this facility. This table only includes those requirements cited in the application as applicable and determined by the Department to be not applicable, or the Department determined that the requirement does not impose any conditions on a regulated piece of equipment.

Table 103.B: Non-Applicable Requirements

Non-Applicable Requirements	(1)	(2)	Justification For Non-Applicability
N/A			

1. Not Applicable for This Facility: No existing or planned operation/activity at this facility triggers the applicability of these requirements.
2. No Requirements: Although these regulations may apply, they do not impose any specific requirements on the operation of the facility as described in this permit.

C. Compliance with the terms and conditions of this permit regarding source emissions and operation demonstrate compliance with national ambient air quality standards specified at 40 CFR 50, which were applicable at the time air dispersion modeling was performed for the facility's NSR Permit P154-R2M1.

A104 Facility: Regulated Sources

A. Table 104.A lists the emission units authorized for this facility. Emission units identified as insignificant or trivial activities (as defined in 20.2.70.7 NMAC) and/or equipment not regulated pursuant to the Act are not included.

Table 104.A: Regulated Sources List

Unit No.	Source Description	Make	Model	Serial No.	Construction/ Reconstruct Date	Manuf. Date	Manufacturer Rated Capacity /Permitted Capacity
903	4SLB RICE	Cooper-Bessemer	LSV-16SSG	7030	1959	1959	4500 hp / 4500 hp
904	4SLB RICE	Cooper-Bessemer	LSV-16SSG	7029	1959	1959	4500 hp / 4500 hp
921	4SRB RICE Generator	Ingersoll-Rand	PSVG-6	6BPSC280	1959	1959	408 hp /408 hp
MIST-1	Mist Extractor Tank	N/A	N/A	N/A	1980	1980	1,140 gal/ 365 bbl /y Combined MIST-1 & MIST-2
MIST-2	Mist Extractor Tank	N/A	N/A	N/A	2006	2006	50 gal/ 365 bbl /y Combined MIST-1 & MIST-2
TK-1	Tank - Above Ground	N/A	N/A	N/A	1980	1980	500 bbl/ 365 bbl /y Combined 6 Tanks
TK-30	Tank - Above Ground	N/A	N/A	N/A	2006	2006	2,500 gal/ 365 bbl /y Combined 6 Tanks
TK-31	Tank - Above Ground	N/A	N/A	N/A	2006	2006	2,500 gal
TK-32	Tank - Above Ground	N/A	N/A	N/A	2006	2006	1,000 gal/ 365 bbl /y Combined 6 Tanks
TK-33	Tank - Above Ground	N/A	N/A	N/A	2006	2006	1,000 gal/ 365 bbl /y Combined 6 Tanks
TK-34	Tank - Above Ground	N/A	N/A	N/A	2006	2006	1,000 gal/ 365 bbl /y Combined 6 Tanks
SVE-1	Soil Vapor Extractor & Thermal Oxidizer	Baker Furnace	200 CFM	286	2003	1996	200 CFM
SVE-2	Soil Vapor Extractor & Thermal Oxidizer	Baker Furnace	200 CFM	285	2003	1996	200 CFM
SSM/M	Startup, Shutdown, Maintenance, and Malfunctions	N/A	N/A	N/A	N/A	N/A	N/A

1. All TBD (to be determined) units and like-kind engine replacements must be evaluated for applicability to NSPS and MACT requirements.

A105 Facility: Control Equipment

A. Table 105.A lists all the pollution control equipment required for this facility. Each emission point is identified by the same number that was assigned to it in the permit application.

Table 105.A: Control Equipment List:

Control Equipment Unit No.	Control Description	Pollutant being controlled	Control for Unit No.[1]
SVE-1	Thermal Oxidizer	VOCs & HAPs	SVE-1
SVE-2	Thermal Oxidizer	VOCs & HAPs	SVE-2

1 Control for unit number refers to a unit number from the Regulated Equipment List

B. Thermal Oxidizer (Units SVE-1 and SVE-2)

Requirement: (1) The off-gas from the SVE Systems shall be controlled by the Thermal Oxidizer. (2) The permittee shall maintain the units according to manufacturer's or supplier's recommended maintenance. (NSR Permits 1776M1 and 1777M1, condition A200.B)
Monitoring (1) The thermal oxidizer shall be operated in accordance with manufacturer's or supplier's recommendations and parameters. The SVE System shall not be operated without the thermal oxidizer except for periods of startup and shutdown as recommended by manufacturer or supplier. The permittee shall monitor times of maintenance and type of maintenance that occurred. (2) The permittee shall monitor the total hours of operation in either thermal or catalytic modes.
Recordkeeping: The permittee shall record the hours of operation in each mode daily and maintain records in accordance with Section B109.
Reporting: The permittee shall report in accordance with Section B110.

A106 Facility: Allowable Emissions

A. The following Section lists the emission units, and their allowable emission limits. (40 CFR 50; 40 CFR 63, Subparts A and ZZZZ, GGGGG, Paragraphs 1, 7, and 8 of 20.2.70.302.A NMAC; NSR Permits 1776M1, 1777M1, and 6742).

Table 106.A: Allowable Emissions

Unit No.	[1]NO_x pph	NO_x tpy	CO pph	CO tpy	VOC pph	VOC tpy
903	125.0	547.5	16.5	72.3	9.9	43.4
904	125.0	547.5	16.5	72.3	9.9	43.4

Table 106.A: Allowable Emissions

Unit No.	[1]NO_x pph	NO_x tpy	CO pph	CO tpy	VOC pph	VOC tpy
921	12.0	27.0	6.8	15.3	<	<
MIST 1&2; TK-1, TK-30, TK-31, TK-32, TK-33, and TK-34	-	-	-	-	11.3	13.3
SVE-1	0.06	0.27	0.05	0.23	0.42	1.83
SVE-2	0.06	0.27	0.05	0.23	0.42	1.83

1 Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2.
2 Title V annual fee assessments are based on the sum of allowable tons per year emission limits in Sections A106 and A107.
3 To report excess emissions for sources with no pound per hour and/or ton per year emission limits, see condition B110.E.
"-" indicates the application represented emissions are not expected for this pollutant.
"<" indicates that the application represented the uncontrolled mass emission rates are less than 1.0 pph or 1.0 tpy for this emissions unit and this air pollutant. The Department determined that allowable mass emission limits were not required for this unit and this pollutant.

A107 Facility: Allowable Startup, Shutdown, & Maintenance (SSM) and Malfunction Emissions

A. The maximum allowable SSM and Malfunction emission limits for this facility are listed in Table 107.A and were relied upon by the Department to determine compliance with applicable regulations.

Table 107.A: Allowable SSM and Malfunction Units, Activities, and Emission Limits

Unit No.	Description	VOC (tpy)
SSM/M from [901, 902, 903, 904, 921]	[1]Compressor & Associated Piping Blowdowns during Routine and Predictable Startup, Shutdown, and/or Maintenance (SSM); and Malfunctions.	10.0

1. This authorization does not include VOC combustion emissions.
2. Units 901 and 902 are electric engines that drive compressors and the emissions here are from the blow down of the compressors.
3. To report excess emissions for sources with no pound per hour and/or ton per year emission limits, see condition B110.E.



about GHD

GHD is one of the world's leading professional services companies operating in the global markets of water, energy and resources, environment, property and buildings, and transportation. We provide engineering, environmental, and construction services to private and public sector clients.

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January 23, 2020 Reference No. 11203587

Kerwin Singleton
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505

Dear Mr. Singleton:

Re: Additional Information for Four Factor Analysis
Roswell Compressor Station
Transwestern Pipeline Company, LLC

GHD Services, Inc. (GHD) is submitting, on behalf of Transwestern Pipeline Company, LLC., responses to the New Mexico Environmental Department (NMED) request for additional information dated December 23, 2019 regarding the four-factor analysis completed for the Roswell Compressor Station. These responses correspond to the NMED Regional Haze Second Planning Period Progress Analysis under the Clean Air Act (CAA) and Regional Haze Rule (40 CFR §51.300 to 51.309).

If you have any questions or concerns, please contact myself at (720) 974-0937 or Larry Campbell at (575) 625-8022.

Sincerely,

GHD



Sergio Guerra
Project Manager

SG/AW/1

Encl. Responses to NMED Request for Additional Information for Four-Factor Analysis

cc: Larry Campbell – Transwestern Pipeline Company, LLC.

GHD
14998 West 6th Avenue Suite 800 Golden Colorado 80401 USA
T 720 974 0935 **F** 720 974 0936 **W** www.ghd.com

REGISTERED COMPANY FOR ISO 9001 ENGINEERING DESIGN

Responses to NMED Additional Information Request Dated December 23, 2019

Four Factor Analysis
Roswell Compressor Station
Transwestern Pipeline Company, LLC

Attachments Index

Attachment A – Cooper Quote for Low Emission Controls retrofit
Attachment B – Selected Pages from Chapter 2 SCR, EPA Cost Control Manual (updated June 2019)
Attachment C – Selected Pages from Chapter 1 SNCR, EPA Cost Control Manual (updated April 2019)
Attachment D – Updated Electronic Cost Analysis Spreadsheet
Attachment E – NMED Additional Information Request Letter dated December 23, 2019

1. What options does the quotation from Cooper Machinery Services evaluate for emission reductions (i.e., upgrades to the air-to-fuel ratio (AFR) controller, turbocharger, adjusting ignition timing, installing cylinder heads fitted with pre-combustion chambers, larger intercooling applications, enhanced mixing, bypass valves, and increased ignition energy)? Please provide a copy of the quotation that shows the Low Emission Controls (LEC) upgrades presented can lower NO_x emission rates to 2.5 grams per horsepower-hour (g/hp-hr.). Consider and include a discussion of variations of LEC upgrades that might lower the cost of compliance while still achieving meaningful NO_x reductions.
Please see attached Cooper Machinery quote (Attachment A) that shows upgrades that lower NOx emission rates to 2.5 g/hp-hr. The vendor, Cooper Machinery, provided the LEC upgrades applicable to these engines to control NOx emissions from the engines at the Roswell facility and stated that the full package of CBT is necessary to achieve emission reductions. The retrofit upgrades presented and quoted by Cooper include:

1) Install new cylinder heads fitted with precombustion chambers
2) Replace existing water-cooled pulse type exhaust manifold with a dry constant pressure manifold.
3) Add bypass valve to exhaust manifold to permit control of intake manifold pressure by bypassing some exhaust from the turbocharger.
4) Upgrade turbocharger to flow more air into combustion chamber
5) Remove existing expansion turbo-coolers.
6) Replace small intercoolers with larger intercoolers.
7) Add pilot fuel lines and pressure control for precombustion chamber fuel

2. The referenced document indicating that selective catalytic reduction (SCR) retrofits have not occurred as of 2014 is dated 2014, so it may not reflect applications that may have occurred since that document was published. Please verify that there have been no SCR retrofits on RICE in the gas transmission industry and provide additional information on why this technology is not appropriate for your operation. This additional information is important, as the costs of control ($4,300-$5,500/ton NO_x removed) may be considered reasonable.
Chapter 2 of the EPA cost manual (updated June 2019) (Attachment B) supports the 2014 reference document cited in the Four Factor Analysis dated October 30, 2019. According to the EPA cost manual, the only example provided for SCR technology used on a RICE engine occurred in 1994 on a new 1,800 hp diesel-fired engine but not for a natural gas engine. All other examples of SCR applications were for other types of combustion equipment often in industries other than oil & gas.

3. Please include a discussion on the technical feasibility of non-selective catalytic reduction for the Cooper-Bessemer compressor engines. If it is determined that this option is technically feasible, please complete a four-factor analysis for this technology.
Based on Section 3.2 of the INGAA source referenced in the Four Factor Analysis, non-selective catalytic reduction (NSCR) is a control used on rich burn RICE engines and the Cooper-Bessemer compressor engines are four stroke lean burn RICE engines. Therefore, NSCR is not compatible and not a technically feasible control option (INGAA, Availability and Limitations of NOx Emission Control Resources, 2014).

Selective non-catalytic reduction (SNCR) is less effective in reducing NOx emissions than SCR and is only applied to similar equipment as SCR, such as industrial boilers. Chapter 1 of the EPA cost manual (updated April 2019) (Attachment C) supports this information and provides no examples or indication that this technology can be applied to engines. Please also see additional information provided in response 2 above.

4. Consider Good Combustion Practices (GCP) and routine maintenance as controls and provide details on how these would be achieved, including a maintenance schedule and operating procedures.
Energy Transfer performs regular inspection and maintenance activities for the equipment on site. Maintenance schedule and procedures and the associated tracking, monitoring, testing, and recordkeeping are required in the facility operating permit.

5. Please consider and include a discussion on the feasibility of replacing natural gas-fueled engines with commercial electric powered compressors.
Energy Transfer estimated the cost of a 4500 hp electric engine to replace each existing natural gas fired one at $6,512,932.09. This conservative cost estimate and an estimated O&M cost were used to calculate a cost per ton value in the attached spreadsheet (Attachment D).

6. Please provide a current quote on the installation of SCR on Units 903 and 904, as adjusting costs from a quote obtained in 1994 is not appropriate.
SCR is not a feasible technology for gas-fired engines based on Chapter 2 of the EPA cost manual (updated June 2019) (Attachment B) and a four-factor analysis should not have been completed for these engines. In 1994, the technology was being evaluated for feasibility on engines, which is why costs from that period are available, however, no other recent references were found.

7. Submit all electronic spreadsheets used for control technology calculations.
Please see attached electronic spreadsheet (Attachment D) which includes an updated cost analysis for electric replacement compressors.

Attachment A

Andy White

From: Bailey, Bob (Cooper, Non-GE) <Bob.Bailey@bhge.com>
Sent: Tuesday, January 14, 2020 8:54 PM
To: Andy White
Cc: Sergio Guerra; Phil Horn
Subject: RE: Engine Retrofit - Low Emission Controls - Roswell and Mountainair

Andrew, to achieve lower emissions the full package must be done.

Installing jetcell heads will definitely make the engines run with greater stability, however, this the improved combustion will result in lower exhaust temperatures as more fuel will go to providing effective work. The lower temperatures will reduce the energy needed to drive the turbocharger so there will not be sufficient air to lean out the air/fuel mixture necessary to reduce NOx emissions.

To achieve the leaner air/fuel mixture with jetcell heads requires a higher efficiency constant pressure turbocharger with a constant pressure exhaust manifold. To be able to control air fuel ratio, it is necessary to control the turbocharger speed. To do this we install a wastegate before the turbocharger which allows some of the exhaust gas to bypass the turbocharger. This is not possible with the pulse type manifold currently installed on the engine because it has individual pipes for each cylinder collecting into multiple inlets on the turbine casing.

The higher air flow from the turbocharger will require larger coolers to be installed to keep intake manifold temperature within limits.

We have provided a quick budget number with some consideration that this project may not be done for several years. Is there an estimated schedule for the job?

Best regards
Bob Bailey

From: Andrew.White2@ghd.com <Andrew.White2@ghd.com>
Sent: Friday, January 10, 2020 5:33 PM
To: Bailey, Bob (Cooper, Non-GE) <Bob.Bailey@bhge.com>
Cc: Sergio Guerra <Sergio.Guerra@ghd.com>; Phillip.Horn@ghd.com
Subject: EXT: RE: Engine Retrofit - Low Emission Controls - Roswell and Mountainair

Hi Bob,

Thanks for providing the general LEC quote below to my colleague Phil Horn back in October and hope 2020 is starting well for you.

The State of Mexico has asked for Cooper to now provide cost estimates for each of the individual upgrades mentioned below (i.e. install new cylinder heads, replace manifold, add bypass valve, etc.). They are interested in whether a “partial package” of upgrades might be more cost effective for controlling NOx emissions than the full $1,800,000 package. Would you be able to provide this for us?

Thanks very much for your help with this and please let me know any questions.

Best regards,

Andy White
720-974-0965

From: Bailey, Bob (Baker Hughes) <Bob.Bailey@bhge.com>
Sent: Thursday, October 17, 2019 9:56 PM
To: Phil Horn <Phillip.Horn@ghd.com>
Subject: RE: Engine Retrofit - Low Emission Controls - Roswell and Mountainair

Hello Phil

After doing some discussions we can upgrade these engines by doing following:

Install new cylinder heads fitted with precombustion chambers

Replace existing water cooled pulse type exhaust manifold with a dry constant pressure manifold.

Add bypass valve to exhaust manifold to permit control of intake manifold pressure by bypassing some exhaust from the turbocharger.

Upgrade turbocharger to flow more air into combustion chamber

Remove existing expansion turbo-coolers.

Replace small intercoolers with larger intercoolers.

Add pilot fuel lines and pressure control for precombustion chamber fuel.

Considering the age and condition of the engines, these changes will allow reliable operation with NoX emissions of 2.5 gm/bhp-hr at full load. This would be better stated in lb/hr and I will get you that value tomorrow.

Budget price for this is US$ 1,800,000 per engine.

I trust this will meet your needs for now (I will get you lb-hr value tomorrow).

Best regards
Bob Bailey

From: Phillip.Horn@ghd.com <Phillip.Horn@ghd.com>
Sent: Thursday, October 17, 2019 10:42 AM
To: Bailey, Bob (Baker Hughes) <Bob.Bailey@bhge.com>
Subject: EXT: RE: Engine Retrofit - Low Emission Controls - Roswell and Mountainair

Hi Bob,

Were you able to get a general quote yesterday?

Attachment B

Chapter 2
Selective Catalytic Reduction

John L. Sorrels
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

David D. Randall, Karen S. Schaffner, Carrie Richardson Fry
RTI International
Research Triangle Park, NC 27709

June 2019

DISCLAIMER

This document includes references to specific companies, trade names and commercial products. Mention of these companies and their products in this document is not intended to constitute an endorsement or recommendation by the U.S. Environmental Protection Agency.

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2. SELECTIVE CATALYTIC REDUCTION

2.1 Introduction

Selective catalytic reduction (SCR) has been applied to stationary source fossil fuel-fired combustion units for emission control since the early 1970s and is currently being used in Japan, Europe, the United States, and other countries. In the U.S. alone, more than 1,000 SCR systems have been installed on a wide variety of sources in many different industries, including utility and industrial boilers, process heaters, gas turbines, internal combustion engines, chemical plants, and steel mills [1]. Other sources include fluid catalytic cracking units (FCCUs), ethylene cracker furnaces, nitric acid plants, catalyst manufacturing processes, nitrogen fixation processes, and solid/liquid or gas waste incinerators [2, 3]. In the U.S., SCR has been installed on more than 300 coal-fired power plants ranging in size from less than 100 megawatt equivalent (MWe) to 1,400 MWe [1, 4]. Other combustion sources with large numbers of SCR retrofits include more than 50 gas-fired utility boilers ranging in size from 147 MWe to 750 MWe, more than 50 industrial boilers and process heaters (both field-erected and packaged units), and more than 650 combined cycle gas turbines [1]. SCR can be applied as a stand-alone nitrogen oxides (NO_x) control or with other technologies, including selective non-catalytic reduction (SNCR)[1] and combustion controls such as low NO_x burner (LNB) and flue gas recirculation (FGR) [2].

SCR is typically implemented on stationary source combustion units requiring a higher level of NO_x reduction than achievable by selective non-catalytic reduction (SNCR) or combustion controls. Theoretically, SCR systems can be designed for NO_x removal efficiencies up close to 100 percent. In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NO_x controls such as LNB or FGR that achieve relatively low emissions on their own. The outlet concentration from SCR on a utility boiler is rarely less than 0.04 lb/million British thermal units (MMBtu) [1].[2] In comparison, SNCR units typically achieve approximately 25 to 75 percent reduction efficiencies [5].

Either ammonia or urea may be used as the NO_x reduction reagent in SCR systems. Urea is generally converted to ammonia before injection. Results of a survey of electric utilities that operate SCR systems indicated that about 80 percent use ammonia (anhydrous and aqueous), and the remainder use urea [4]. A survey of coal-fired power plants that control NO_x emissions using either SCR or SNCR found anhydrous ammonia use exceeds aqueous ammonia use by a ratio of 3 to 1. Nearly half of these survey respondents also indicated that price is their primary consideration in the choice of reagent; safety is the primary consideration for about 25 percent of the operators [6].

SCR capital costs vary by the type of unit controlled, the fuel type, the inlet NO_x level, the outlet NO_x design level, and reactor arrangement. Capital costs also rose between 2000 and 2010 (at least for utility boiler applications), even after scaling all data to 2011 dollars (2011$).

[1] A hybrid SNCR/SCR system was demonstrated at the AES Greenidge Power Plant in 2006. However, no hybrid SNCR/SCR systems are currently known to be operating as of February 2016.

[2] Data in the Clean Air Markets Division (CAMD) database also suggest SCR units rarely achieve emissions less than 0.04 lb/MMBtu.

For a small number of early SCR retrofits on utility boilers prior to 2000, the average costs were about $100/kilowatt (kW), in 2011$, and there was little scatter in the data. From 2000 to 2007, the SCR costs for 32 utility boilers ranged from about $100/kW to $275/kW (2011$), and a slight economy of scale was evident (i.e., using a regression equation, costs ranged from about $200/kW for a 200 MW unit to $160/kW for an 800 MW unit). For 2008 to 2011, the average SCR costs exhibited great variability and again a modest economy of scale was evident (i.e., about $300/kW for a 200 MW unit to $250/kW for an 800 MW unit; 2011$). For eight utility boilers either installed in 2012 or projected to be installed by 2014, the SCR costs ranged from about $270/kW to $570/kW (2011$). The generating capacity for these units ranged from 400 MW to 800 MW [7]. Typical operation and maintenance costs are approximately 0.1 cents per kilowatt-hour (kWh) [8, 9]. Table 2.1a provides capital cost estimates for electric utility boilers, and Table 2.1b presents capital cost estimates for SCR applications of various sizes in several other industry source categories.

The procedures for estimating costs presented in this report are based on cost data for SCR retrofits on existing coal-, oil-, and gas-fired boilers for electric generating units larger than 25 MWe (approximately 250 MMBtu/hr). Thus, this report's procedure estimates costs for typical retrofits of such boilers. The methodology for utility boilers also has been extended to large industrial boilers by modifying the capital cost equations and power consumption (electricity cost) equations to use the heat input capacity of the boiler instead of electric generating capacity.[3] The procedures to estimate capital costs are not directly applicable to sources other than utility and industrial boilers. Procedures to estimate annual costing elements other than power consumption are the same for SCR units in any application. The cost of SCR as part of a new plant often is likely to be less than the cost for retrofitting an SCR at an existing plant. Appropriate factors to estimate the cost of a new plant SCR have been included. In addition, the cost procedures in this report reflect individual SCR applications. Retrofitting multiple boilers with SCR can allow for some economies of scale for installation, thus yielding some reduction in capital costs per SCR application. The cost methodology incorporates certain approximations; consequently, it should be used to develop study-level accuracy (±30 percent) cost estimates of SCR applications. Such accuracy in the cost methodology is consistent with the accuracy of the cost estimates for the other control measures found in this Cost Manual as stated in Section 1.

In the cement industry, pilot tests in the 1970s and 1990s showed that SCR could be a feasible control technology for cement kilns. Building on that experience, SCRs were first installed in Europe in 2001. Today, SCR has been successfully implemented at seven European cement plants in Solnhofer, Germany (operated from 2001 until 2006), Bergamo, Italy (2006), Sarchi, Italy (2007), Mergelstetten, Germany (2010), Rohrdorf, Germany (2011), Mannersdorf, Austria (2012), and Rezatto, Italy (2015) [10, 11, 12]. As of 2015, there is only one cement plant in the U.S. that has installed an SCR. This SCR began operation in 2013 and is installed after an electrostatic precipitator. The control efficiency for the system is reported to be about 80 percent, which is consistent with SCR applications on European kilns. SCRs have not seen widespread use in the U.S. cement industry mainly due to industry concerns regarding potential problems caused by high-dust levels and catalyst deactivation by high sulfur trioxide (SO_3) concentrations

[3] The term "industrial" boilers as used in the Control Cost Manual includes industrial, commercial, and institutional (or ICI) boilers, unless otherwise noted.

from pyritic sulfur found in the raw materials used by U.S. cement plants. The SO_3 could react with calcium oxide in the flue gas to form calcium sulfate and with ammonia to form ammonium bisulfate. The calcium sulfate could deactivate the catalyst, while the ammonium bisulfate could cause catalyst plugging. There have been concerns expressed about the potential for catalyst poisoning by sodium, potassium, and arsenic trioxide. Finally, other concerns expressed are that dioxins and furans may form in the SCR due to combustion gases remaining at temperatures between 450 degrees Fahrenheit (°F) and 750°F. These and other concerns regarding the implementation of SCR to the cement industry are discussed in detail in "Alternative Control Techniques Document Update – NO_x Emissions from New Cement Kilns" [10]. Due to the small number of SCRs installed at cement plants, information on capital and operating costs for SCRs at cement plants is limited. The installation and operating costs for the SCR installed at the U.S. plant in 2013 are not publicly available at this time. In general, we expect the capital and operating costs would be higher than for low-dust applications due to the need to install catalyst cleaning equipment for SCR systems installed in high-dust configurations and for heating the flue gas in low-dust, tail-end configurations.

Table 2.1a: Summary of SCR Cost Data for Utility Boilers

Source Category	Unit Size	Fuel Type	Capital Cost			$ Year	Comments	Reference
			Min	Avg	Max			
Electric Generating Units	NA[a]	NA	$55/kW		$140/kW	<2000$[b]	Retrofit costs.	[13]
	~300-1,400 MW	NA	~$70/kW		~$120/kW	<2000$[b]	Retrofit costs. Six boilers. No economy of scale.	[13]
	150–1,000 MW	Coal	$80/kWnet[c]		$160/kWnet[c]	2002$	Retrofit costs. Author of referenced document scaled original costs to 2002 dollars. More than 20 boilers. Little to no economy of scale.	[14]
	NA	Coal	$60/kW	$100kW	$200/kW	<2004$[b]	Retrofit costs	[15]
	<300 MW	Coal		$167/kW	$186/kW	<2004$	Costs for 26 boilers.	[16]
	301–600 MW	Coal		$148/kW	$192/kW	<2004$	Costs for 15 boilers.	[16]
	601–900 MW	Coal		$124/kW	$221/kW	<2004$	Costs for 22 boilers.	[16]
	>900 MW	Coal		$118/kW	$195/kW	<2004$	Costs for 9 boilers.	[16]
	100–399 MW	Coal	$70/kW	$123/kW	~$175/kW	<2004$[b]	Costs for 5 boilers.	[17]
	400–599 MW	Coal	$73/kW	$103/kW	~$160/kW	<2004$[b]	Costs for 8 boilers.	[17]
	600–899 MW	Coal	$56/kW	$81/kW	~$100/kW	<2004$[b]	Costs for 9 boilers.	[17]
	>900 MW	Coal	~$80/kW	$117/kW	~$190/kW	<2004$[b]	Costs for 10 boilers.	[17]
	191 MW	Coal		$149/kW		2006$	Retrofit costs.	[18]
	~100 MW-~800MW	NA	~$125/kW	$275/kW	~$440/kW	2008$	Retrofit costs for 15 boilers installed in 2008 to 2010. Most costs between $200/kW and $350/kW. Slight economy of scale—regression average about $340/kW for 100 MW to $250/kW for 800 MW.	[8]
	~400 MW to ~800 MW	NA	~$270/kW	~$420/kW	~560/kW	2011$	Retrofit costs for 8 boilers either installed in 2012 or projected to be installed by 2014.	[7]

[a] Not Available.

[b] Year of reference.

[c] Net kilowatts.

Table 2.1b: Summary of SCR Cost Data for Miscellaneous Industrial Sources

Source Category	Unit Size	Fuel Type	Capital Cost: average (range)	$ Year	Actual, Vendor Quote, or Estimated?	Comments	Reference
Industrial-Commercial Boilers	350 MMBtu	Coal	NA ($10,000–$15,000/MMBtu/hr)	1999$	Estimated	Retrofit costs. Authors of referenced document estimated the low end of the range assuming a cost of about $100/kW for a 100 MW (1000 MMBtu/hr) utility boiler and assuming that economies of scale would be greater for utility boilers than for industrial boilers (so that the cost for a 350 MMBtu/hr industrial boiler would be comparable to or greater than the cost for a 1000 MMBtu/hr utility boiler on a $/MMBtu basis).	[19]
	100–1,000 MMBtu/hr	Coal	NA ($7,300–$14,600/MMBtu/hr)	1999$	Estimated	Retrofit costs. Generally costs available for one boiler with each type of fuel. Authors of referenced document estimated costs for other sizes assuming ratio of small-to-large $/MMBtu costs are related to ratio of large to small heat inputs raised to the 0.3 power.	[20]
	100–1,000 MMBtu/hr	Oil	NA ($5,550–$11,100/MMBtu/hr)	1999$	Estimated		[20]
	100–1,000 MMBtu/hr	Gas	NA ($4,010–$8,010/MMBtu/hr)	1999$	Estimated		[20]
	100 MMBtu/hr	Gas	NA ($7,500/MMBtu/hr)	1999$[b]	Vendor	Cited source in reference [15] is an unpublished letter from a vendor.	[19]
	350 MMBtu	Oil, Gas, or Wood	NA ($4,000–$6,000/MMBtu/hr)	1999$	Estimated		[21]
	57 MMBtu/hr	Wood	NA (>$560,000 and $9,500/MMBtu/hr)	1999$[c]	Actual/ Estimate	Costs for a new boiler.	[19]
	321 MMBtu/hr	Wood	NA ($1,980/MMBtu/hr)	2006$	Likely Estimated		[22]
Petroleum Refining – Steam Boilers	650 MMBtu/hr	Gas or refinery fuel gas	NA ($3,100–$25,800/MMBtu)	2004$ [c]	Estimated	Retrofit costs. Equipment costs based on range of costs found in literature search (references were not provided). Installation costs estimated using factors from the Control Cost Manual for thermal and catalytic incinerators.	[23]
Petroleum Refining – Process Heaters	350 MMBtu/hr	Gas/refinery fuel gas	NA ($3,100–$25,800/MMBtu)	2004$ [c]	Estimated	Same comment as above.	[23]
	350 MMBtu/hr	Refinery oil	NA ($3,100–$25,800/MMBtu)	2004$ [c]	Estimated	Same comment as above.	[23]

Source Category	Unit Size	Fuel Type	Capital Cost: average (range)	$ Year	Actual, Vendor Quote, or Estimated?	Comments	Reference
	10 MMBtu/hr	Gas or refinery fuel gas/NG combo	$19,200/MMBtu ($12,000–$26,500/MMBtu)	1999[b]	Vendor/ Estimated	Costs are based primarily on quotes from two vendors (and additional discussions). Authors of the referenced report added costs for fan, motor, and ductwork costs based on procedures in the Control Cost Manual.	[24]
	50 MMBtu/hr	Gas or refinery fuel gas/NG combo	$5,140/MMBtu ($4,020–$6,280/MMBtu)	1999[b]	Vendor/ Estimated	Same comment as above.	[24]
	75 MMBtu/hr	Gas or refinery fuel gas/NG combo	$4,190/MMBtu ($3,440–$4,950/MMBtu)	1999[b]	Vendor/ Estimated	Same comment as above.	[24]
	150 MMBtu/hr	Gas or refinery fuel gas/NG combo	$2,730/MMBtu ($2,570–$2,880/MMBtu)	1999[b]	Vendor/ Estimated	Same comment as above.	[24]
	350 MMBtu/hr	Gas or refinery fuel gas/NG combo	$1,550/MMBtu ($1,520–$1,570/MMBtu)	1999[b]	Vendor/ Estimated	Same comment as above.	[24]
	68 MMBtu/hr (Two 32 MMBtu/hr)	Refinery fuel gas	NA ($22,100/MMBtu)	1991	Actual	Retrofit costs.	[19]
Petroleum Refining – FCCU	70,000 barrels/stream day (bbl/stream day)	NA	NA ($9.0 million)	2004$[c]	Vendor	Estimated cost by vendor (for 90 percent reduction).	[3]
	27,000 bbl/stream day	NA	NA ($8-$12 million)	2009	Estimated		[25]

Source Category	Unit Size	Fuel Type	Capital Cost: average (range)	$ Year	Actual, Vendor Quote, or Estimated?	Comments	Reference
	<20,000->100,000 bbl/stream day	NA	NA (order of magnitude range; low end higher than two entries above)	2005 to 2010	Actual	Costs reported by 6 petroleum refining companies for 7 FCCUs in responses to EPA ICR. One new, 6 retrofits.	[26]
	NA	NA	NA ($20 million)	2006	Actual	Approximate average cost for SCR retrofits at several refineries	[27]
Portland Cement (dry kilns)	1.09 million short tpy clinker	NA	NA ($6.9 per short ton clinker)	2006[a]	Estimated	Retrofit cost. Estimate based primarily on SCR procedures for boilers in fifth edition of the Control Cost Manual. Clinker capacity obtained from the second reference.	[28,29]
	1.13 million short tpy clinker	NA	NA ($5.9 per short ton clinker)	2006[a]	Estimated	Same comment as above.	[28,29]
	2.16 million short tpy clinker	NA	NA ($3.9 per short ton clinker)	2006[a]	Estimated	Same comment as above.	[28,29]
	1.4 million short tpy clinker	NA	NA ($5.9 per short ton clinker)	2004	Not clear	Retrofit cost for European kiln. Cost in euros converted to dollars assuming a ratio of $1.3/euro.	[30]
	1.055 million tpy clinker	NA	NA ($4.4 per short ton clinker)	2004	Estimated	Cost for new kiln.	[31]
	1.095 million short tpy clinker	NA	NA ($4.4 per short ton clinker)	2011	Estimated	Cost for new kiln. Cost based on quote for the SCR equipment, and standard installation factors from the Control Cost Manual for other types of control devices.	[32]
Portland Cement (wet kilns)	0.3 million short tpy clinker	NA	NA ($17.5 per short ton clinker)	2006[a]	Estimated	Retrofit costs for 4 kilns. Rated clinker production capacity obtained from the second reference.	[28,33]
	0.320 million short tpy clinker		NA ($15.6-$16.6 per short ton clinker)	2006[a]	Estimated	Retrofit costs for 3 kilns. Rated clinker production capacity obtained from second reference.	[28,29]

Source Category	Unit Size	Fuel Type	Capital Cost: average (range)	$ Year	Actual, Vendor Quote, or Estimated?	Comments	Reference
Gas Turbine, Simple Cycle	NA	Gas	NA ($50-$70/kW)	1999$[a]	Vendor	Retrofit costs.	[19]
	80 MW	Gas	NA ($51/kW)	1999$[a]	Vendor	Retrofit cost, excluding balance of plant costs.	[19]
	2 MW	Gas	NA ($237/kW)	1999$[a]	Vendor	Retrofit cost.	[19]
	12 MW	Gas	NA ($167/kW)	1999$[a]	Vendor	Retrofit cost.	[19]
Internal Combustion Engine	1,800 hp[d]	Diesel (No. 2 fuel oil)	NA ($0.18 million)	1994	Actual	New cost	[19]

[a] Year of reference.

[b] Year analysis was conducted (assumed vendor contacts were made that year).

[c] Commission year of the SCR.

[d] Horsepower.

Attachment C

Revised —4/25/2019

Chapter 1

Selective Noncatalytic Reduction

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April 2019

DISCLAIMER

This document includes references to specific companies, trade names and commercial products. Mention of these companies and their products in this document is not intended to constitute an endorsement or recommendation by the U.S. Environmental Protection Agency.

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1. SELECTIVE NONCATALYTIC REDUCTION

1.1 Introduction

Selective noncatalytic reduction (SNCR) is a post combustion emissions control technology for reducing NO_x by injecting an ammonia type reactant into the furnace at a properly determined location. This technology is often used for mitigating NO_x emissions since it requires a relatively low capital expense for installation, albeit with relatively higher operating costs. Japan originally developed SNCR for oil and gas units in the 1970s; Western Europe followed by applying the science to coal fired units in the late 1980s and the U.S electric power sector began installations on coal plants in the early 1990s. More than 45 gigawatts of coal-fired power capacity in the U.S. now have SNCR.[1] SNCR is now used beyond the electric power industry, and is currently being used to control NO_x emissions from a multitude of combustion sources, including industrial boilers, electric utility steam generators, thermal incinerators, cement kilns, pulp and paper power boilers, steel industry process units, refinery process units, and municipal solid waste energy recovery facilities [1, 2, 3]. It is being used on industrial boilers covering a wide range of sizes from <50 MMBtu/hr to more than 800 MMBtu/hr [2]. SNCR is also being used on a wide range of sizes of utility boilers from <50 MW to more than 900 MW. More than half of utility boilers with SNCR are relatively small (<50 – 200 MW) but about 24 percent are larger than 300 MW.[1] Over 70 percent of the utility boilers using SNCR burn coal as the primary fuel and most of the others burn biomass, but the other types of combustion sources are burning a wide range of materials [2].[1] SNCR can be applied as a standalone NO_x control or with other technologies such as combustion controls. The SNCR system can be designed for seasonal or year-round operations.

Reported SNCR reduction efficiencies vary over a wide range. Temperature, residence time, type of NO_x reducing reagent, reagent injection rate, uncontrolled NO_x level, distribution of the reagent in the flue gas, and CO and O_2 concentrations all affect the reduction efficiency of the SNCR [2]. Tables 1.1 and 1.2 and Figures 1.1a, 1.1b, and 1.1c summarize emission reductions for SNCR applications in a variety of industries [2]. Findings based on review of these data are as follows:

- Although installation of urea-based systems is more common than ammonia-based deployments, operating data reveal higher NO_x reductions occur with ammonia reagent. Table 1.1 shows the median (as a measure of average) reductions for urea-based SNCR systems in various industry source categories range from 25 to 60 percent, while median reductions for ammonia-based SNCR systems range from 61 to 65 percent. Note that most of the boilers with ammonia-based SNCR systems that are fired with solid fuels are fired with wood or municipal solid waste. Figure 1.1b shows nearly all ammonia-based systems have reduction efficiencies greater than 40 percent, while several urea-based systems have lower reduction efficiencies.

[1] Spreadsheet of information provided to EPA's Clean Air Market Division from query of SNL Energy data on 1/22/2015.

Table 1.1: Summary of NO_x Reduction Efficiencies Obtained Using SNCR on Different Types of Boilers in the U.S. [2]

Type of source category	Fuel	NO_x reduction reagent	Average boiler size	Median NO_x reduction (%)
Electric utility	Coal	Urea	320 MW	25
Co-generation	Primarily wood, some coal, biomass, and tires	Urea	360 MMBtu/hr	50
Pulp & paper (P&P)	Primarily bark and wood waste, supplemented with a variety of other fuels	Urea	410 MMBtu/hr	50
Municipal waste combustion (MWC)	Municipal solid waste (MSW)	Urea	270 MMBtu/hr	37
Refinery CO boilers	Typically refinery fuel gas	Urea	320 MMBtu/hr	60
Miscellaneous combustion units	Primarily wood, MSW, or coal	Ammonia	400 MMBtu/hr	65
Miscellaneous combustion units	Primarily crude oil or gas	Ammonia	110 MMBtu/hr	61

Table 1.2: SNCR NO_x Reduction Efficiency by Industry and Reagent Type [2, 4]

Industry and Units	**% Reduction**	
	Ammonia-Based	**Urea-Based**
Cement Kilns	12-77	25–90
Chemical Industry	NA[a]	35–80
Circulating Fluidized and Bubbling Bed Boilers	76–80	NA
Coal, Wood and Tire Fired Industrial and IPP/Co-Generations Boilers	NA	20–75
Coal-Fired Boilers	38–83	20–66
Gas- and Oil-Fired Industrial Boilers	30–75	NA
Glass Melting Furnaces	51–70	NA
Steel Products Industry	NA	42.9–90
Municipal Waste Combustors	45-70	16–87
Oil- and Gas-Fired Heaters	45–76	NA
Process Units	NA	40–85
Pulp and Paper Industry	NA	20–62
Refinery Process Units and Industrial Boilers	NA	20–75
Stoker-Fired and Pulverized Coal-Fired Boilers	50–83	NA
Stoker-Fired Wood-Fueled Boilers	40–75	NA
Vapor, Sludge and Hazardous Waste Incinerators	65–91	NA

[a]NA means not available.

Attachment D

Electronic Spreadsheet Provided Separately

Attachment D
RICE Engine Baseline Emissions, Reductions, and Control Cost Analysis
Roswell Compressor Station - Chaves County, New Mexico

2016 EI	Unit 903		LEC		Electric Replacement	
Rated HP	4500		Rated HP	4500	Rated HP	4500
2016 Operating Hours	3607		NOx Emission Factor [1] (g/hp-hr)	2.5	NOx Emission Factor [1] (g/hp-hr)	0
Test NOx Emission Rate (lb/hr)	37.19		2016 Operating Hours	3607	2016 Operating Hours	3607
NOx emissions (ton/yr)	67.07		New NOx Emission Rate (lb/hr)	24.80	New Nox Emission Rate (lb/hr)	0.00
			NOx Emission Equivalent (ton/yr)	44.73	Nox Emission Equivalent (ton/yr)	0.00
			Difference (tons)	22.34	Difference (tons)	67.07
			% Reduction	**33%**	**% Reduction**	**100%**
			2019 $/ton	**$ 15,308**	**2019 $/ton**	**$ 18,450**

Permitted Rate	Unit 904		LEC		Electric Replacement	
Rated HP	4500		Rated HP	4500	Rated HP	4500
2016 Operating Hours	971		NOx Emission Factor [1] (g/hp-hr)	2.5	NOx Emission Factor [1] (g/hp-hr)	0
PTE NOx Emission Rate (lb/hr)	125		2016 Operating Hours	971	2016 Operating Hours	971
NOx emissions (ton/yr)	60.69		New NOx Emission Rate (lb/hr)	24.80	New Nox Emission Rate (lb/hr)	0.00
			NOx Emission Equivalent (ton/yr)	12.04	Nox Emission Equivalent (ton/yr)	0.00
			Difference (tons)	48.65	Difference (tons)	60.69
			% Reduction	**80%**	**% Reduction**	**100%**
			2019 $/ton	**$ 7,030**	**2019 $/ton**	**$ 20,391**

[1] Lowest achievable emission factor, per Cooper Machinery quote

LEC Cost	
Quote From Cooper Machinery Services - 10/17/19	
LEC Cost Description	**2019 $**
Total Capital Cost	1,800,000
Annual O&M Cost (estimate)	270,000
Total Annual Cost per Year	342,000

Electric Replacement Cost	
Quote from Energy Transfer	
Cost Description	**2019 $**
Total Capital Cost	6,512,932.09
Annual O&M Cost (estimate)	976,940
Total Annual Cost per Year	1,237,457

*Estimated useful life of LEC or electric replacement: 25 years
*Estimated Annual O&M cost as a percent of the Total Capital Investment: 15 %

Attachment E

NEW MEXICO
ENVIRONMENT DEPARTMENT

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Michelle Lujan Grisham
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Howie C. Morales
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James C. Kenney
Cabinet Secretary

Jennifer J. Pruett
Deputy Secretary

December 23, 2019

Mr. Larry Campbell
Transwestern Pipeline
6381 Main Street
Roswell, NM 88201

larry.campbell@energytransfer.com

Subject: Request for Additional Information for Four-Factor Analysis under the Regional Haze Program

Dear Mr. Campbell:

This letter is to request additional information for the Transwestern Pipeline Company, LLC four-factor analysis for the Roswell Compressor Station. The four-factor analysis report was received by the New Mexico Environment Department (NMED) on November 1, 2019. Pursuant to NMED's Regional Haze Guiding Principles, the four-factor analysis must consider new ideas that potentially offer better solutions to problems and must evaluate the newest engineering methods and technology advances in potential control measures.

Please provide the following information for the reciprocating internal combustion engines (RICE) that were evaluated in four-factor analysis for potential nitrogen oxides (NO_X) controls.

1. What options does the quotation from Cooper Machinery Services evaluate for emission reductions (i.e., upgrades to the air-to-fuel ratio (AFR) controller, turbocharger, adjusting ignition timing, installing cylinder heads fitted with pre-combustion chambers, larger intercooling applications, enhanced mixing, bypass valves, and increased ignition energy)? Please provide a copy of the quotation that shows the Low Emission Controls (LEC) upgrades presented can lower NO_X emission rates to 2.5 grams per horsepower-hour (g/hp-hr.). Consider and include a discussion of variations of LEC upgrades that might lower the cost of compliance while still achieving meaningful NO_X reductions.
2. The referenced document indicating that selective catalytic reduction (SCR) retrofits have not occurred as of 2014 is dated 2014, so it may not reflect applications that may have occurred since that document was published. Please verify that there have been no SCR retrofits on RICE in the gas transmission industry and provide additional information on why this technology is not appropriate for your operation. This additional information is important, as the costs of control ($4,300-$5,500/ton NO_X removed) may be considered reasonable.
3. Please include a discussion on the technical feasibility of non-selective catalytic reduction for the Cooper-Bessemer compressor engines. If it is determined that this option is technically feasible, please complete a four-factor analysis for this technology.

4. Consider Good Combustion Practices (GCP) and routine maintenance as controls and provide details on how these would be achieved, including a maintenance schedule and operating procedures.
5. Please consider and include a discussion on the feasibility of replacing natural gas-fueled engines with commercial electric powered compressors.
6. Please provide a current quote on the installation of SCR on Units 903 and 904, as adjusting costs from a quote obtained in 1994 is not appropriate.
7. Submit all electronic spreadsheets used for control technology calculations.

Please note that per EPA's Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019), "as part of meeting the requirement of the Regional Haze Rule for the state to document the cost and engineering information on which the State is relying every source-specific cost estimate used to support an analysis of control measure must be documented in the SIP". If you feel that your supplemental information should be classified as confidential business information (CBI), it will need to be reviewed and approved as such by NMED and EPA. Submit CBI with the word 'confidential' included in the electronic file name and on each page of the document. Do not combine non-confidential business information and CBI in the same files. Also, the claimant must satisfy the conditions in 20.2.1.115.B(3)(a)-(d) NMAC when the CBI is submitted. Until NMED and EPA determines if the information qualifies as CBI, the information will not be disclosed to anyone other than those listed in 20.2.1.115 NMAC.

NMED respectfully requests that your company submit the additional information on four-factor analysis electronically as soon as possible to Mark Jones at mark.jones@state.nm.us and myself at kerwin.singleton@state.nm.us. Please contact NMED if you have questions about the additional information request. We encourage your questions in order to help expedite the technical analysis required under the Regional Haze Program. Staff would be happy to meet with you in person to discuss these requirements in more detail. Likewise, staff may further contact you with questions or require additional information during its review of your submittals.

Thank you for your assistance in this matter. Should you have questions or require clarification, please contact me at 505.476.4350, or Mark Jones at 505.566.9746.

Sincerely,

Kerwin C. Singleton
Planning Section Chief

Memorandum

09/10/2020

To:	Mark Jones, NMED	Ref. No.:	11203587
From:	Sergio Guerra, GHD, William Yenke, Larry Campbell, Kerry Egan- Transwestern Pipeline Company, LLC	Tel:	720-974-0937
CC:			

Subject: **Four Factor Analysis - Roswell and Mountainair Compressor Stations**

GHD Services, Inc. (GHD) is submitting, on behalf of Transwestern Pipeline Company, LLC (Transwestern) responses to the New Mexico Environmental Department (NMED) comments sent via email on August 27, 2020 regarding the four-factor analysis completed for the Mountainair and Roswell Compressor Stations. These responses correspond to the NMED Regional Haze Second Planning Period Progress Analysis under the Clean Air Act (CAA) and Regional Haze Rule (40 CFR §51.300 to 51.309).

1. Responses to NMED Comments on the Roswell Compressor Station

1) NMED revised the cost estimate based on 2016 – 2018 average emissions and operating hours. Since Unit 904 performed better than the vendor's guarantee for NOX emissions, would the facility be willing to accept a lower permitted emission rate? This would ensure that the unit will continue to operate at that rate in the future. Otherwise, there is no guarantee that the utilization for this unit will not increase resulting in higher NOX emissions.

   Response: Transwestern is willing to work with NMED on looking at the option of reducing the current NOx permit limit. However, additional work will have to be done to identify an emission factor that is achievable.

2) The annualized cost did not consider an interest rate associated with the capital cost. NMED revised calculations assumed the current bank prime rate of 3.25%.

   Response: Comment is acknowledged. The revised calculations include the interest rate.

3) Replacing engines with electric compressors.

   Response: Electric compressor replacement cost estimates have been updated for the Roswell Compressor Station.

   The total capital investment (TCI) for electric compressor replacement at Roswell Compressor Station has been updated to approximately $12 million. This estimate includes the following factors:

   - *Removing and replacing gas engines with electric motors and VFD to existing compressor;*

- *Pouring and leveling foundation;*
- *Modifying gearbox, control buildings, oil coolers, gas piping; and*
- *Updating electrical components (substation build, conduit/cable install to PCR, VFD, motor, gearbox, control room, etc.).*

In addition to this capital investment, monthly utility bills would be approximately doubled to account for the electric compressors. The average annual utility cost is estimated to increase by $2.3 million.

As shown in the Attachment A, the new cost estimates bring reduction costs to $12,310 per year-ton of reduced emissions for Unit 903 and $178,863 per year-ton of reduced emissions for Unit 904.

2. Responses to NMED Comments on the Mountainair Compressor Station

1) The annualized cost did not consider an interest rate associated with the capital cost. NMED revised calculations assumed the current bank prime rate of 3.25%.

   Response: Comment is acknowledged. The revised calculations include the interest rate.

2) Mountainair Compressor Station – Replacing engines with electric compressors. This cannot be eliminated at the feasibility step based on costs, so we will need to discuss feasibility and cost estimates further.

   Response: Electric compressor replacement cost estimates have been updated for those at the Mountainair Compressor Station.

   The total capital investment (TCI) for electric compressor replacement at Mountainair Compressor Station has been updated to approximately $24 million. This estimate includes the following factors:

   - *Constructing new compressor buildings, foundations, gas piping for 3 electric motors, VFDs and compressors;*
   - *Installing approximately 8.5 miles of 115kV transmission line;*
   - *Modifying gearbox, control buildings, oil coolers, gas piping; and*
   - *Updating electrical components (substation build, conduit/cable install to PCR, VFD, motor, gearbox, control room, etc.).*

   In addition to this capital investment, the average annual utility cost is estimated to be $5.3 million.

   As shown in the Attachment B, the new cost estimates bring reduction costs to at least $16,888 per year-ton of emissions reduced for Unit 701, $10,641 per year-ton of emissions reduced for Unit 702, and $7,739 per year-ton of emissions reduced for Unit 703.

3. Additional Notes

Another impact of electric compressor replacement is the limited facility capacity during construction. This would impact pipeline capacity for existing customers with firm contract agreements.

These cost estimates come from Energy Transfer's senior planning engineer George Mayer who has overseen similar replacements at Roswell Compressor Station and Station 4 (a compressor station in Arizona). These are the best available estimates based on the previous projects. Note that these are minimum cost estimate values as we have not included maintenance or labor in our O&M costs. We will continue to refine costs as any additional information becomes available.

Attachments

Attachment A
Roswell CS Cost Analysis

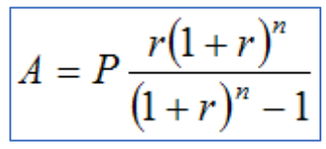
TWP - Roswell Compressor Station CS 4-Factor Analysis

TWP Amortization of equipment			
Current Bank Prime Rate - "r"		3.25%	
Cooper Bessemer LSV-16SSG, Unit 903, 4500 hp			
Low Emission Controls			
Total Capital Outlay (TCI) for control equip (each) - "P"	$	1,800,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	106,271	
Annual O&M Costs	$	270,000	
Total Annual Costs	$	376,271	
Baseline NOx Emissions (tpy)		122.2	(from 2016-18 Emissions Inventory submissions - AEIR)
Emissions with LEC (tpy)		54.44	(based on vendor guarantee of 2.5 g/hp-hr and 2016 - 2018 average operating hours)
Emissions Reduction (tpy)		67.76	
% Reduction		55.5%	
Cost: 2019 $/yr-ton	$	5,553	(this value is slightly higher than the consultants estimate of $5,047/ton)
Electric Replacement			
Total Capital Outlay (TCI) for control equip (each) - "P"	$	6,000,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	354,236	
Annual O&M Costs	$	1,150,000	< Includes utilities cost only
Total Annual Costs	$	1,504,236	
Baseline NOx Emissions (tpy)		122.2	(from 2016-18 Emissions Inventory submissions - AEIR)
Emissions with electric replacement (tpy)		0	
Emissions Reduction (tpy)		122.20	
% Reduction		100.0%	
Cost: $/yr-ton	$	12,310	(this value confirms the Permittee's calculation)
Cooper Bessemer LSV-16SSG, Unit 904, 4500 hp			
Low Emission Controls			
Total Capital Outlay (TCI) for control equip (each) - "P"	$	1,800,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	106,271	
Annual O&M Costs	$	270,000	
Total Annual Costs	$	376,271	
Baseline NOx Emissions (tpy)		8.41	(from 2016-18 Emissions Inventory submissions - AEIR)
Emissions with LEC (tpy)		13.43	(based on vendor's guarantee of 2.5 g/hp-hr and average 2016-2018 operating hours)
Emissions Reduction (tpy)		-5.02	
% Reduction		-59.7%	
Cost: $/yr-ton	$	(74,954)	

$$A = P\frac{r(1+r)^n}{(1+r)^n - 1}$$

Electric Replacement

Total Capital Outlay (TCI) for control equip (each) - "P"	$	6,000,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	354,236	
Annual O&M Costs	$	1,150,000	< Includes utilities cost only
Total Annual Costs	$	1,504,236	
Baseline NOx Emissions (tpy)		8.41	(from 2016-18 Emissions Inventory submissions - AEIR)
Emissions with electric replacement (tpy)		0	
Emissions Reduction (tpy)		8.41	
% Reduction		100.0%	
Cost: $/yr-ton	$	178,863	



Attachment B
Mountainair CS Cost Analysis

TWP Mountainair CS Equipment Amortization

8/11/2020

Annualized TCI - "A" Equation

$$A = P\frac{r(1+r)^n}{(1+r)^n - 1}$$

Assumed Discount Rate - "r" 3.25% Prime rate as of 8/6/2020

Unit 701 - Cooper Bessemer rLSV-16G

LEC

Total Capital Outlay (TCI) for control equip (each) - "P"	$	1,800,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	106,271	
Annual O&M Costs	$	270,000	
Total Annual Costs	**$**	**376,271**	
Baseline NOx Emissions (tpy)		132.58	2016-2018 EI
Emissions with control (tpy)		37.21	
Emissions Reduction (tpy)		95.37	
% Reduction		71.9%	
Cost: $/yr-ton	**$**	**3,945**	

Electric Compressor

Total Capital Outlay (TCI) for control equip (each) - "P"		8,000,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	472,315	
Annual O&M Costs		1,766,667	< Only accounts for utilities
Total Annual Costs	**$**	**2,238,981**	
Baseline NOx Emissions (tpy)		132.58	2016-2018 EI
Emissions with control (tpy)		0	
Emissions Reduction (tpy)		132.58	
% Reduction		100.0%	
Cost: $/yr-ton	**$**	**16,888**	

Unit 702 - Cooper Bessemer rLSV-16G

LEC

Total Capital Outlay (TCI) for control equip (each) - "P"	$	1,800,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	106,271	
Annual O&M Costs	$	270,000	
Total Annual Costs	**$**	**376,271**	
Baseline NOx Emissions (tpy)		210.41	2016-2018 EI
Emissions with control (tpy)		44.55	
Emissions Reduction (tpy)		165.86	
% Reduction		78.8%	
Cost: $/yr-ton	**$**	**2,269**	

Electric Compressor			
Total Capital Outlay (TCI) for control equip (each) - "P"		8,000,000	Jal used the CPI/inflation to arrive at this figure rather than a current quote
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	472,315	
Annual O&M Costs		1,766,667	< Only accounts for utilities
Total Annual Costs	**$**	**2,238,981**	
Baseline NOx Emissions (tpy)		210.41	2016-2018 EI
Emissions with control (tpy)		0	
Emissions Reduction (tpy)		210.41	
% Reduction		100.0%	
Cost: $/yr-ton	**$**	**10,641**	

Unit 703 - Cooper Bessemer rLSV-16G			
LEC			
Total Capital Outlay (TCI) for control equip (each) - "P"	$	1,800,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	106,271	
Annual O&M Costs	$	270,000	
Total Annual Costs	**$**	**376,271**	
Baseline NOx Emissions (tpy)		289.33	2016-2018 EI
Emissions with control (tpy)		70.26	
Emissions Reduction (tpy)		219.07	
% Reduction		75.7%	
Cost: $/yr-ton	**$**	**1,718**	

Electric Compressor			
Total Capital Outlay (TCI) for control equip (each) - "P"		8,000,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	472,315	
Annual O&M Costs		1,766,667	< Only accounts for utilities
Total Annual Costs	**$**	**2,238,981**	
Baseline NOx Emissions (tpy)		289.33	2016-2018 EI
Emissions with control (tpy)		0	
Emissions Reduction (tpy)		289.33	
% Reduction		100.0%	
Cost: $/yr-ton	**$**	**7,739**	

From: Egan, Kerry L <kerry.egan@energytransfer.com>
Sent: Thursday, March 25, 2021 2:03 PM
To: Jones, Mark, NMENV; Sergio Guerra
Cc: Baca, Michael, NMENV; Yenke, William; Singleton,Kerwin, NMENV; Egan, Kerry L
Subject: [EXT] RE: Mountainair Compressor Station / RE: Roswell Compressor Station 4-factor analysis

Mark,

Good afternoon. I appreciate your patience as we worked to collect the data necessary to provide you with the fuel gas costs for these facilities. We are presenting data that Transwestern has used to prepare and submit the Annual Form 2 filing to FERC for years 2016 – 2018. I'm presenting this information in as streamlined and usable fashion as possible.

	CY 2016 Annual Fuel Costs ($)	CY 2017 Annual Fuel Costs ($)	CY 2018 Annual Fuel Costs ($)		CY 2016 Average Fuel Cost per Compressor Engine* ($)	CY 2017 Average Fuel Cost per Compressor Engine * ($)	CY 2018 Average Fuel Cost per Compressor Engine* ($)
Station #7 Mountainair CS	570,945.00	865,835.00	1,003,748.00		190,315.00	288,611.67	334,582.67
Station #9 Roswell CS	255,657.00	300,864.00	334,370.00		127,828.5	150,432.00	167,185.00

Please review the presented data and let me know if you should have any questions. If you require any additional information, please let me know and I will work to respond as quickly as I can.

Respectfully,

ENERGY TRANSFER

Forbes | 2019 AMERICA'S BEST LARGE EMPLOYERS

Kerry Egan
Environmental Specialist
Energy Transfer Company
Office: 575-347-6512
Cell: 575-808-9402
8501 Jefferson NE
Albuquerque, NM 87113

ENERGY TRANSFER

Transwestern Pipeline Company

August 11, 2023

New Mexico Environment Department – Air Quality Bureau

525 Camino de Los Marquez – Suite 1

Santa Fe, NM 87505

Attn: Michael Baca, NMED-AQB

Mark Jones, NMED-AQB

Kenneth Miller, NMED-AQB

Mr. Baca,

Transwestern Pipeline Company, LLC (Transwestern) is providing the following response to the meeting held with New Mexico Environment Department – Air Quality Bureau (NMED) representatives and Transwestern on July 11, 2023. Specifically, Transwestern is addressing the questions and additional information requests raised by NMED (see Attachment A) regarding the Four Factor Analyses for the Mountainair and Roswell Compressor Stations.

These responses correspond to the NMED Regional Haze Second Planning Period Progress Analysis under the Clean Air Act (CAA) and Regional Haze Rule (40 CFR §51.300 to §51.309).

Please review at your earliest convenience and contact me with any questions concerning the submission.

Respectfully,

Kerry Egan

Mr. Kerry Egan
Sr. Environmental Specialist

Energy Transfer Company

O: 505-260-4023
C: 575-808-9402

8501 Jefferson St NE

Albuquerque, NM 87113

Four Factor Analysis

Roswell and Mountainair Compressor Stations

Transwestern Pipeline Company, LLC

Attachments Index:

Attachment A - 07-11-2023 Meeting Agenda and Additional Questions From NMED

Attachment B - Updated Cost Analysis Spreadsheets (v. 08-11-2023)

Attachment C – Supplemental Information For Cost Evaluations

1) Updated cost estimate for Cooper Low Emissions Control Technology installation on existing units.
2) Updated cost estimate for electrification of compressor stations and replacment of existing units.
3) Cost estimate for the replacement of existing units with Solar Turbines compressor packages

NMED Requests For Additional Information

1) What plans, if any, does ETC - Transwestern Pipeline have for retiring or replacing any of the Compressor Engines at either facility?

As discussed in the meeting on 7-11-2023, Transwestern currently has no definitive plans for the retirement or replacment of any units covered by the Four Factor Analysis (4FA). Given the current demand on Transwestern's pipeline system, retirement of units is not an option. The current firm shipping contracts with customers will require full utilization of compression at Transwestern mainline facilities. Transwestern's commercial and marketing groups anticipate this level of demand will remain in place for the foreseeable future.

In recent years Transwestern has evaluated the operational and economic feasibility of upgrading these compressor stations with new horsepower. In the most recent (CY2023) rate case submitted to the Federal Energy Regulatory Commission (FERC), Transwestern proposed a plan of modernization by replacement of existing units with new compressor packages. The proposal was not approved during the review and negotions of the rate case between Transwestern, FERC and the customers accessing Transwestern's pipeline system. The next regular rate case is not anticipated to occurr for at least five years. At that time the proposal for modernization may be taken up again. If approved at that time, the modernization project would be completed over several years (as defined in the rate case). Transwestern has no estimated timeline for the eventual replacement of the existing units.

2) How does ETC - Transwestern Pipeline plan to comply with the ozone precursor rule with respect to the compressor engines?

Transwestern is actively working to establish compliance programs for all applicable poritons of the Ozone Precursor Rule (NMAC 20.2.50). The Mountainair Compressor Station is not located in an affected county under the Ozone Precursor Rule. The Roswell Compressor Station is located in Chaves county, and is subject to the rule.

Currently the only engines accounted for in the 4FA subject to the rule, are units 903 and 904 at the Roswell Compressor Station. Transwestern is actively evaluating our options to achieve compliance with the newly established emissions limitations for existing gas driven engines.

The options for compliance mirror those that were established in the 4FA: 1) Cooper Low Emissions Control (LEC) technology installation, 2) Electrification of the station and replacment of gas driven engines with electric motors, 3) Replacement with new units (in this case Solar Turbines).

The Ozone Precursor Rule establishes the following emissions limitation for the existing units 903 and 904.

Table 1 - EMISSION STANDARDS FOR EXISTING NATURAL GAS-FIRED SPARK IGNITION ENGINES

NO_x	CO	NMNEHC (as propane)
0.5 g/bhp-hr.	0.60 g/bhp-hr.	0.70 g/bhp-hr.

As identified on the latest call between NMED and Transwestern, the Cooper LEC technology is not a suitable means of achieving compliance with the Ozone Precursor Rule. The guarantees provided by Cooper for emissions reductions do not meet the 0.5 g/bhp-hr limitation established by the Ozone Precursor Rule. As such, Transwestern is requesting the NMED recognize this is not a viable emissions reduction strategy for the Regional Haze Initiative, and should be excluded from the 4FA for these units.

This leaves the options of replacement of the existing units with electric motors or turbines. Transwestern continues to review and evaluate which course of action is the most ecnomical, conducive to current operations and in line with current business planning. In accordance with NMAC 20.2.50.113(B)(2), all existing natural gas-fired spark ignition engines must be in compliance with the emissions limitations found in Table 1, by January 1, 2029. Given the cost, complexity and integral nature units 903 and 904 to Transwestern's operations, we plan to address these units in the last grouping of engines from the entire affected fleet. Transwestern anticipates having the final plan to address these units in place on or before January 1, 2026. This should leave sufficient time to complete necessary work, prior to the January 1, 2029 deadline. At that time, Transwestern can provide updated information to the NMED if needed.

3) Is projected utilization of the Compressor Engines expected to be appreciably different than historical utilization?

Yes. The original 4FA prepared and presented to the NMED, utilized operational data from 2016 – 2018. Utilization has increased significantly at both compressor stations for the 2019 –

2022 time period. In 2022, utilization at the Mountainair compressor station was 261% of the utilization during 2016. At Roswell station, 2022 utilization was 366% of 2016 utilization.

Given the current firm shipping contracts in place, Transwestern anticipates both stations will remain at or near full utilization for the foreseeable future.

Unit	Annual Operating Hours					
	2019	2020	2021	2022		4-yr Avg
701	7084.3	7295.7	7553.2	8347.6		7570.2
702	8491.0	7571.7	7607.5	7352.2		7755.6
703	8189.0	8208.5	7312.2	8400.1		8027.5
Total:	23764.3	23076.0	22473.0	24099.8		23353.3
% of 2016 Total Hours	257%	250%	243%	261%		

Unit	Annual Operating Hours					
	2019	2020	2021	2022		4-yr Avg
903	8079.4	8696.3	8217.4	8303.8		8324.2
904	6651.5	8489.7	7843.5	8476.5		7865.3
Total:	14730.9	17186.0	16060.9	16780.3		16189.5
% of 2016 Total Hours	322%	375%	351%	366%		

4) Is ETC- Transwestern Pipeline's cost-of-capital notably different than the current prime rate of ~8%?

In consultation with Energy Transfer's financial planning personnel, we've determined that 8% cost-of-capital is appropriate for the purposes of this analysis. This rate is subject to frequent change, and may not be appropriate for long term (greater than 1 year) planning or cost analysis.

5) Does ETC - Transwestern Pipeline plan to provide updated cost evaluations for any of the pollution control options it evaluated in its submitted Four Factor Analysis? If so, when should NMED expect to receive that information?

Transwestern has updated cost evaluations for the emissions reduction strategies presented in the 4FA. The updated evaluation spreadsheets are presented in Attachment B for your review. Transwestern attempted to update the evaluations based on best available information from vendors. Transwestern's Asset Management & Reliability, and Project Planning personnel worked to prepare the updated costs.

Given the short timeframe for response, and the complexity of work involved, Transwestern was not able to prepare a complete Request For Proposal (RFP), to provide to vendors. For large capital projects such as these, Transwestern would normally prepare a RFP, have job showings with vendors and allow them to develop detailed proposals.

The cost evaluations provided were prepared with the best information available at this time. Previous vendor quotes and costs associated with prior projects of a similar nature, were utilized to devleop the cost evaluations. Transwestern requests the NMED recognize that these numbers are not set in stone, and may not represent the full cost of the projects if we were to move forward. Additionally, Transwestern and our vendors are subject to the same extreme price volatility and material availability experienced by the entire engery and manufacturing industry. The cost evaluations provided today, will likely not be valid in one year's time. Certain vendors that were able to provide cost estimates have expressly stated that they will have minimum built in cost increases on an annual basis.

6) Does ETC - Transwestern Pipeline anticipate continued availability of maintenance parts for the Compressor Engines for 10 to 20 more years?

Transwestern does generally anticipate the ability to maintain these units in the near to medium term future. However, in general it is very difficult to estimate the availability of maintenance parts/components, and economic viabiltiy of maintaining these units, ten to 20 years from now.

As discussed on the initial call, material availability is a concern for the existing units. While Transwestern has not yet run into the issue of being unable to replace/repair components on the engines, the costs have been steadily increasing. Additionally, there have been instances where specific parts/components had to be specifically manufactured as no commercially

available options existed. Additionally, the significant supply chain disruptions cuased by the Covid-19 pandemic continue to be problematic.

Further complicating the matter is the effect proposed environmental regulations will have on the availability of materials. The EPA recently published the Good Neighbor Rule, affecting hundreds, if not thousands, of gas-fired reciprocating engines in the Natural Gas Transmission industry across the country (Note: The GNR proposal currently does not affect New Mexico). The effect of the rule may be the retirement of numerous engines similar to those operated by Transwestern. This may provide an opportunity to acquire surplus materials from these engines for the ongoing maintenance of our engines. Alternatively, the GNR may force numerous engines to adopt similar emissions reduction strategies as those evaluated here, causing the demand increases and subsequent price increases. Until the GNR has been implemented throughout the affected industry, it will be difficult to determine its ultimate effect on availability and pricing.

One of Transwestern's primary concerns with implementing the Cooper LEC technology on the existing units, is maintenance feasibility. While the LEC technology would be beneficial in the long term goal of NOx reductions, it would not alleviate the issues associated with ongoing maintenance. In fact the installation of additional equipment would increase the burden of maintenance, and potentially have a negative impact on Transwestern's long-term ability to maintain the overall unit. Accordingly, Transwestern considers the LEC technology as the least viable option, from an operational standpoint.

7) Estimates of maintenance costs for the units?

Transwestern has provided estimates of the operations and maintenance (O&M) costs for the various emissions reduction strategies, in the cost evaluation spreadsheet. The O&M costs were developed using actual costs realized at the Mountainair and Roswell stations, as well as similar costs at other stations, in the 2022 and 2023 budget years. The 2022 costs were based on year end totals. The 2023 costs were based on Year-To-Date (YTD) totals, and adjusted for a full year of operation.

The costs for electric units and turbines were taken from several other Transwestern stations operating similar equipment. It can be assume that due to similar equipment, operations, and utilization, the O&M costs should be similar as well.

8) Does ETC - Transwestern Pipeline plan to provide a cost evaluation for the replacement of the existing Compressor Engines with new, like-kind engines? If so, when should NMED expect to receive that information?

Transwestern did provide a cost evaluation for the replacement of existing engines in the cost evaluation spreadsheets. See Attachment B.

As previously mentioned (response to question #1), Transwestern has evaluated the potential to upgrade/modernize the compressor stations in question. As a part of that process Transwestern has determined that replacement with turbines would be preferable to replacement with new reciprocating engines. This is due to the nature of the operations at the mainline transmission compressor stations. Turbines better suite the need for continuous long term utilization, with minimal downtime interuptions for maintenance. Turbines generally require less maintenance outages than comparable reciprocating engines. The cost on a $/horsepower basis for a new turbine is comparable to that for a new reciprocating engine.

Finally, the NOx emissions reductions realized by installing new turbines would support the goals of NMED to reduce Regional Haze. Solar Turbines current fleet of gas compressor turbines are designed to have very low NOx emissions rates. They are certified to meet the new emissions limitations found in NMAC 20.2.50.113(B)(7) Table 2.

9) Does ETC - Transwestern Pipeline plan to provide a cost evaluation for the replacement of the existing Compressor Engines with electric motor equivalents? If so, when should NMED expect to receive that information?

Transwestern has provided a cost evaluation for the replacement of the existing engines with electric motors.

The cost was developed using information Transwestern had previously compiled for similar electrification projects. These costs were adjusted to current figures, using assumptions about inflation and general cost increases in the intervening years. Given the complexity involved with the electrification of the compressor station, significant input from the local utility providers would be needed to prepare a more accurate, current quote. Transwestern attempted to coordinate with utility providers to develop cost estimates for the large

expenditures such as running new electric transmission lines, constructing substations, and verifying the ability of the utility to meet the added load demand. However, project coordination with the utility providers can often take months or more than a year.

Transwestern requests the NMED recognize that the costs provided here are as accurate as we can provide at the current time. The ultimate costs may increase significantly depending on the manner in which the project proceeds, and the timeline for execution of the potential project.

10) Please provide documentation in support of estimated electrification costs. (For example, if a new electrical substation would be necessary to support increased facility demand, ETC - Transwestern Pipeline should provide details about how the estimated cost of the substation was determined.)

Transwestern has provided the best available documentation for the estimated cost of electrification. See Attachment C.

Transwestern's Asset Management & Reliability and Projects Planning groups have prepared the cost estimates using information available from other projects, previously scoped, and adjusted to current dollars. The cost evaluation spreadsheet details the particular work required for the electrification option.

A fully comprehensive Request For Proposal (RFP) would be required to develop a truly accurate and current cost estimate. As mentioned above, the truncated timeline provided for response, and the inability of utility providers to give detailed estimates in a short time frame, made an RFP infeasible.

Should the NMED have any questions regarding the cost evaluations, Transwestern will provide further information.

Attachments

Attachment A:

07-11-2023 Meeting Agenda and Additional Questions From NMED

Regional Haze: Energy Transfer Co. - Transwestern Pipeline

Draft Agenda

Date: Tuesday, July 11, 2023

Time: 2:00 pm – 4:00 pm (MT)

Virtual Teams Meeting (Link)

1. Introductions/welcome

2. NMED status update on Regional Haze State Implementation Plan revision (SIPr)

3. These are key units that previously have been included in **Energy Transfer Co.(ETC)- Transwestern Pipeline - Mountainair #7 Compressor Station (CS) and Roswell #9 CS** Four Factor Analysis as subject to analysis for Regional Haze, or are otherwise of interest for purposes of Regional Haze planning. For reference, the subset of units from the regulated source list table (Table 104.A) in the most recent facility operating permits (P153-R4, renewed on 10/14/2020) and (P154-R4, renewed 9/28/2018) are provided here.

   a. **Mountainair #7 CS**

Table 104.A: Regulated Sources List (subset of units from permit)

EI Unit ID No.	Permit Unit No.	Source Description	Make & Model	Yr of Manufacture	Operating Rate Max/Site	Operating Capacity Max/Site
EQPT1	701	4SLB Internal combustion engine	Cooper Bessemer Engine - LSV-16SG	01-JAN-60	4500 hp / 4500 hp	4500 hp / 365 rpm
EQPT2	702	4SLB Internal combustion engine	Cooper Bessemer Engine - LSV-16SG	01-JAN-60	4500 hp / 4500 hp	4500 hp / 365 rpm
EQPT3	703	4SLB Internal combustion engine	Cooper Bessemer Engine - LSV-16SG	01-JAN-67	4500 hp / 4500 hp	4500 hp / 365 rpm
EQPT4	721	4SLB Internal combustion engine	Ingersoll Rand Engine	01-JAN-60	335 hp / 335 hp	335 hp / 514 rpm
EQPT5	722	4SLB Internal combustion engine	Ingersoll Rand Engine	01-JAN-60	335 hp / 335 hp	335 hp / 514 rpm

1. All TBD (to be determined) units and like-kind engine replacements must be evaluated for applicability to NSPS and MACT requirements.

Table 105.A: Control Equipment List:

Control Equipment Unit No.	Control Description	Pollutant being controlled	Control for Unit No.[1, 2]
721	Oxidation Catalyst	CO	721
722	Oxidation Catalyst	CO	722

1. Control for unit number refers to a unit number from the Regulated Equipment List
2. The control devices were installed to meet the emissions standards required by 40 CFR 63, Subpart ZZZZ. The allowable CO pph and tpy emission limits in Table 106.A of this permit were not reduced to the actual CO post-catalyst emission rates.

b. Roswell #9 CS

Table 104.A: Regulated Sources List (subset of units from permit)

EI Unit ID No.	Permit Unit No.	Source Description	Make & Model	Construction/ Reconstruction Date	Manufacture Date	Manufacturer Rated Capacity /Permitted Capacity
EQPT3	903	4SLB RICE	Cooper-Bessemer - LSV-16SSG	1959	1959	4500 hp / 4500 hp
EQPT4	904	4SLB RICE	Cooper-Bessemer - LSV-16SSG	1959	1959	4500 hp / 4500 hp
EQPT5	921	4SRB RICE Generator	Ingersoll-Rand- PSVG-6	1959	1959	408 hp /408 hp

1. All TBD (to be determined) units and like-kind engine replacements must be evaluated for applicability to NSPS and MACT requirements.

4. General Topics
    a. What plans, if any, does **ETC - Transwestern Pipeline** have for retiring or replacing any of the Compressor Engines at either facility?
    b. How does **ETC - Transwestern Pipeline** plan to comply with the ozone precursor rule with respect to the compressor engines?
    c. Is projected utilization of the Compressor Engines expected to be appreciably different than historical utilization?
    d. Is **ETC- Transwestern Pipeline's** cost-of-capital notably different than the current prime rate of ~8%?
    e. Does **ETC - Transwestern Pipeline** plan to provide updated cost evaluations for any of the pollution control options it evaluated in its submitted Four Factor Analysis? If so, when should NMED expect to receive that information?

5. Operation and Maintenance Costs
    a. Does **ETC - Transwestern Pipeline** anticipate continued availability of maintenance parts for the Compressor Engines for 10 to 20 more years?
    b. Estimates of maintenance costs for the units?

6. Replacement
    a. Does **ETC - Transwestern Pipeline** plan to provide a cost evaluation for the replacement of the existing Compressor Engines with new, like-kind engines? If so, when should NMED expect to receive that information?

7. Electrification
    a. Does **ETC - Transwestern Pipeline** plan to provide a cost evaluation for the replacement of the existing Compressor Engines with electric motor equivalents? If so, when should NMED expect to receive that information?
    b. Please provide documentation in support of estimated electrification costs. (For example, if a new electrical substation would be necessary to support increased facility demand, **ETC - Transwestern Pipeline** should provide details about how the estimated cost of the substation was determined.)

8. Timeline of Four Factor Analysis determinations - draft proposal, required FLM formal consultation, hearing phase (NOI), etc.

9. Questions and answers/ Follow-ups /Next steps

NOTE: NMED requests that the basis of any cost figures provided in support of **ETC - Transwestern Pipeline's** Four Factor Analysis be adequately documented. (For example, the cost to replace an existing engine with a new engine should be accompanied with a vendor quote.)

Attachment B:

Updated Cost Analysis Spreadsheets

(v. 08-11-2023)

TWP - Mountainair Compressor Station CS 4-Factor Analysis

TWP Mountainair CS Equipment Amortization

8/10/2023

Annualized TCI - "A" Equation

$$A = P\frac{r(1+r)^n}{(1+r)^n - 1}$$

Assumed Discount Rate - "r" 8.00% Prime rate as of 7/11/2023

Cooper Bessemer LSV-16SSG, Unit 701, 4500 hp

Low Emission Controls

Total Capital Outlay (TCI) for control equip (each) - "P"	$	5,452,333	
Life Expectancy of control equip (years) - "n"		20	
Annualized TCI - "A"	$	555,332.19	
Annual O&M Costs	$	323,252	Based on 2023 year to date (January - June) O&M costs.
Total Annual Costs	$	878,584	
Baseline NOx Emissions (tpy)		309.1	Calculated using 2019-2022 testing results average and average hours of operation.
NOx Emissions with LEC (tpy)		93.9	Based on vendor guarantee of 2.5 g/hp-hr, and 2019-2022 average operating hours.
Emissions Reduction (tpy)		215.2	
% Reduction		69.6%	
Cost: 2019 $/yr-ton	$	4,083	

Electric Replacement

Total Capital Outlay (TCI) for control equip (each) - "P"	$	12,000,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	1,124,145	
Annual O&M Costs	$	3,153,400	Includes utilities and O&M costs. Based on 2023 YTD costs.
Total Annual Costs	$	4,277,545	
Baseline NOx Emissions (tpy)		309.1	Calculated using 2019-2022 testing results average and average hours of operation.
NOx Emissions with electric replacement (tpy)		0	
Emissions Reduction (tpy)		309.1	
% Reduction		100.0%	
Cost: $/yr-ton	$	13,841	(this value confirms the Permittee's calculation)

Cooper Bessemer LSV-16SSG, Unit 702, 4500 hp			
Low Emission Controls			
Total Capital Outlay (TCI) for control equip (each) - "P"	$	5,452,333	
Life Expectancy of control equip (years) - "n"		20	
Annualized TCI - "A"	$	555,332	
Annual O&M Costs	$	323,252	Based on 2023 year to date (January - June) O&M costs.
Total Annual Costs	$	878,584	
Baseline NOx Emissions (tpy)		463.0	Calculated using 2019-2022 testing results average and average hours of operation.
NOx Emissions with LEC (tpy)		96.2	Based on vendor guarantee of 2.5 g/hp-hr, and 2019-2022 average operating hours.
Emissions Reduction (tpy)		366.9	
% Reduction		79.2%	
Cost: $/yr-ton	$	2,395	
Electric Replacement			
Total Capital Outlay (TCI) for control equip (each) - "P"	$	12,000,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	1,124,145	
Annual O&M Costs	$	3,153,400	Includes utilities and O&M costs. Based on 2023 YTD costs.
Total Annual Costs	$	4,277,545	
Baseline NOx Emissions (tpy)		463.0	Calculated using 2019-2022 testing results average and average hours of operation.
NOx Emissions with electric replacement (tpy)		0	
Emissions Reduction (tpy)		463.04	
% Reduction		100.0%	
Cost: $/yr-ton	$	9,238	

$$A = P\frac{r(1+r)^n}{(1+r)^n - 1}$$

Cooper Bessemer LSV-16SSG, Unit 703, 4500 hp			
Low Emission Controls			
Total Capital Outlay (TCI) for control equip (each) - "P"	$	5,452,333	
Life Expectancy of control equip (years) - "n"		20	
Annualized TCI - "A"	$	555,332	
Annual O&M Costs	$	323,252	Based on 2023 year to date (January - June) O&M costs.
Total Annual Costs	$	878,584	
Baseline NOx Emissions (tpy)		301.7	Calculated using 2019-2022 testing results average and average hours of operation.
NOx Emissions with LEC (tpy)		99.5	Based on vendor guarantee of 2.5 g/hp-hr, and 2019-2022 average operating hours.
Emissions Reduction (tpy)		202.1	
% Reduction		67.0%	
Cost: $/yr-ton	$	4,347	
Electric Replacement			
Total Capital Outlay (TCI) for control equip (each) - "P"	$	12,000,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	1,124,145	
Annual O&M Costs	$	3,153,400	Includes utilities and O&M costs. Based on 2023 YTD costs.
Total Annual Costs	$	4,277,545	
Baseline NOx Emissions (tpy)		301.7	Calculated using 2019-2022 testing results average and average hours of operation.
NOx Emissions with electric replacement (tpy)		0	
Emissions Reduction (tpy)		301.68	
% Reduction		100.0%	
Cost: $/yr-ton	$	14,179	

$$A = P\frac{r(1+r)^n}{(1+r)^n - 1}$$

Units 701, 702, 703 (4500 hp units) Replaced byTwo (2) Solar Mars 90 Turbines			
Replacement w/ Gas Fired Turbine			
Total Capital Outlay (TCI) for control equip (each) - "P"	$	46,250,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	4,332,643.53	
Annual O&M Costs	$	286,000	Based on 2022 O&M costs at TW's similar turbine facility.
Total Annual Costs	$	4,618,644	
Baseline NOx Emissions (tpy)		1073.8	Sum total 701 + 702+ 703. Calculated using 2019-2022 testing results average, and average hours of operatior
NOx Emissions with turbine installation (tpy)		44.74	Based on vendor emissions sheet for proposed unit.
Baseline NOx Emissions of 721 & 722 (tpy)		18.9	Sum total 721 + 722. Calculated using 2019-2022 testing results average and average hours of operation.
NOx Emissions with microtrubine install (tpy)		1.4	Calculated based on generator mfg emissions estimates.
Emissions Reduction (tpy)		1046.51	
% Reduction		97.5%	
Cost: 2019 $/yr-ton	$	4,413	

$$A = P\frac{r(1+r)^n}{(1+r)^n - 1}$$

LSV-16SG Model – 4 Cycle Scope of Supply Solution

- **Properly sized turbocharger, support systems and mounting hardware**
- **Aftercooling system (on engine)**
- **New cylinder heads with pre-combustion chambers with support system**
- **New constant pressure exhaust manifold**
- **ePCC™ System**
- **All engineering installation and commissioning of supplied systems**
- **Supplemental assemble drawings/BOM for new material only**
- **Post Commissioning Support**

AT RISK ITEMS NOT INCLUDED IN SCOPE

- Additional cooling capacity
- Compressed air capacity to handle turbocharger jet-assist during start-up
- High port power cylinders -GMW units (existing cylinders can be ground if not already converted)
- Ignition system must be CPU-2000 or comparable
- Control system upgrades
- Intake air silencer/filter
- Exhaust piping/silencer

$3,100,00 per unit for core LEC upgrade work

30% ($930,000) added for project at risk items

$4,000,000 estimate per unit for LEC

TW Station 7 Gearbox Estimate

Gearbox – Lufkin

$450,000 each / $1,350,000 total for qty 3 units

Labor

$117,000 total each / $350,000 for qty 3 units

Includes grout, per diem, travel, equipment

Total: $1,870,000 for Gearbox installation (includes 10% contingency)

TW Station 7 Controls Upgrade

Existing OPTO control system would need to be repalced with an Allen Bradely system for this project.

$1,000,000 cost for control system upgrade.

Total: $1,000,000 for Controls Upgrade

Total Station 7 Upgrade to LEC

$14,870,000 Total

$16,357,000 Total with 10% contingency

$5,452,333.33 per Unit

Note: This cost estimate is based on a current quote from Cooper for the LEC upgrades, and previous project estimates prepared for the gearbox replacemenet (adjusted for inflation to current dollars).

Electrification of Units 701, 702, 703

1) 2x: 7,500 HP Electric motor, VFD, compressor package, couplings, etc.
2) Foundation pouring and leveling, compressor building, PCR building, station piping, gas cooling
3) Electrical work- conduit/cable install to PCR, VFD, motor, gearbox, control room, etc.
4) Contract and General Labor

-- Construction would have to occur adjacent to existing compression. Units 701, 702 & 703 cannot be taken out of service for the replacement. Current firm shipping contracts require full utilization of compression horsepower at Mountainair CS. This would requrie constructing significant amounts of new infrastructure, not allowing the use of some existing piping, buildings, foundations, coolers, etc..

-- Unknowns- Substation upgrade, transmission line upgrade, utility rate increases

These items would have to be supplied by the local utility. Attempts have been made to attain estimates from utility for station upgrade, without success. The substation upgrade would require an engineering and load study, which itself could result in extended lead times before any decision on technical feasibility.

- This facility is not served by any existing utility provider. Would require a minimum of 8 miles of transmission line. Utility provider has not guaranteed they could or would be willing to provide service to location. Installation of utility line and building a new substation could lead to significant cost increases in comparison to this estimate.

Total Station 7 Electrification Capital Cost

$36,000,000 **Total for station. Includes only items 1-4 above. Cost of third party infrastructure (i.e., substation, transmission line, etc.) and utility cost increases would be in addition to this.**

$12,000,000 **Per unit for electrification.**

Note: This cost estimate is based on previous electrification projects at Transwestern's Mountainair Compressor Station (Unit 901 & 902) and Klagetoh Compressor Station. Both projects were replacements of existing RICE units (similar to units 903 & 904) with electric motors. The project costs were carried forward and adjusted for inflation into current dollars. Given the complex nature of this project and reliance on third parties to provide for and conduct a significant amount of the work (i.e., installation of infrastructure outside of the facility), Transwestern was unable to compile a thorough Request For Proposal. Given the short response period allowed, no vendor proposals were received.

Station 7 Utility Cost & OM Estimate

Station 7 does not currently have electric units in operation, or serviced by a utility provider. O&M costs for the electric units and the projected utility costs were developed by averaging those costs incurred at the Roswell and Klagetoh stations. Both of which have units similar to those that would be installed. This assumes the local power provider is able to supply the necessary load to operate the station.

$112,500 **Projected Annual O&M Cost per unit (based of 2023 YTD expenses).**
$3,040,900 **Projected Annual Utility Cost per unit (based of 2023 YTD expenses).**

$3,153,400 **Projected total O&M plus utility cost, per unit (based on 2023 YTD expenses).**

Replacement of Units 701, 702 & 703 w/ Solar Mars 90 Turbines

1) Purchase two (2) Solar Mars 100 turbine driven gas compressor packages.
2) Foundation pouring and leveling, compressor building, PCR building, station piping, gas cooling
3) Electrical work- conduit/cable install to PCR, VFD, motor, gearbox, control room, etc.
4) Contract and General Labor
5) Requires station control system upgrade for new units.
6) Requires replacement of existing generator Units 721 & 722 with new Capstone microturbine generators.
   - -- This is a requirement to meet the new demand and reliability requirements placed on the station with the installation of turbines.
   - -- Replacement of Untis 721 & 722 with microturbine generator, would result in additional emissions reductions.

-- Construction would have to occur adjacent to existing compression. Units 701, 702, 703 cannot be taken out of service for the replacement. Current firm shipping contracts require full utilization of compression horsepower at Mountainair CS. This would requrie constructing significant amounts of new infrastructure, not allowing the use of some existing piping, buildings, foundations, coolers, etc..

Total Station 7 Turbine Installation Capital Cost

$46,250,000 Total for station. Includes only items 1-5 above.

Note: This cost estimate is based on previously prepared project proposal for an installation of turbines at Mountainair Compressor Station. It should reflect the current cost of the project if completed today. Solar Turbines has instructed TW to anticipate a minimum of 6% cost increase per year for their products. The price increases on labor and other non Solar supplied materials are expected to be similar if not greater.

Station 7 Turbine O&M Estimate

The O&M cost of the turbines has been based on projected costs for other Transwestern stations operating similar (not identical) Solar turbines.

$143,000 Projected total O&M plus utility cost, per unit (based on 2022 expenses at similar station).

	Current Permitted NOx Values	Proposed LEC NOx Values
g/hp-hr	16.66	2.50
lb/hr	165.3	24.80
TPY[1]	724.2	108.63

Unit	Annual Operating Hours 2019	2020	2021	2022		4-yr Avg
701	7084.3	7295.7	7553.2	8347.6		7570.2
702	8491.0	7571.7	7607.5	7352.2		7755.6
703	8189.0	8208.5	7312.2	8400.1		8027.5
Total:	23764.3	23076.0	22473.0	24099.8		23353.3
% of 2016 Total Hours	257%	250%	243%	261%		

Unit		NOx Test Values 2019	2020	2021	2022	4-yr Avg
701	g/hp-hr	6.7	5.6	11.6	9.0	8.2
	lb/hr	66.5	55.8	115.4	88.9	**81.7**
	TPY[1]	291.2	244.6	505.5	389.2	357.6
	TPY[2]	235.5	203.7	435.9	370.9	311.5
	Load %	102.0	83.4	93.4	86.7	91.4
702	g/hp-hr	10.4	11.9	15.4	10.4	12.0
	lb/hr	103.6	117.6	153.2	103.2	**119.4**
	TPY[1]	453.6	515.1	671.1	452.1	523.0
	TPY[2]	439.7	445.2	582.8	379.5	461.8
	Load %	102.0	95.7	84.8	88.4	92.7
703	g/hp-hr	6.1	8.3	6.3	9.6	7.6
	lb/hr	60.1	82.5	62.4	95.7	**75.2**
	TPY[1]	263.2	361.2	273.3	419.1	329.2
	TPY[2]	246.1	338.5	228.1	401.9	303.6
	Load %	105.5	91.8	82.6	88.3	92.1

Notes:

1 The Tons Per Year value is calculated off of 8760 hours of operation, and represent expected worse case emissions.

2 The Tons Per Year value is calculated off of recorded hours of operation, representing actual emissions.

Reported Annual Emissions (TPY)

Unit	2019	2020	2021	2022	4-yr Avg
701	235.5	203.7	435.9	370.9	311.5
702	439.7	445.2	582.8	379.5	461.8
703	246.1	338.5	228.2	401.9	303.6
721	2.6	0.6	0.09	42.42	11.4
722	8.1	15.0	21.51	5.02	12.4

Annual Operating Hours

Unit	2019	2020	2021	2022		4-yr Avg
721	1475.0	1179.8	28.3	6034.0		2179.3
722	7293.8	7609.0	8710.3	2742.2		6588.8
Total:	8768.8	8788.8	8738.6	8776.2		8768.1

NOx Test Values

Unit		2019	2020	2021	2022	4-yr Avg
721	g/hp-hr	0.4	0.1	0.6	1.4	0.6
	lb/hr	3.5	1.0	6.2	14.1	**6.2**
	TPY[1]	15.4	4.5	27.1	61.6	27.1
	TPY[2]	2.6	0.6	0.1	42.4	11.4
	Load %			78.6	61.8	70.2
722	g/hp-hr	0.2	0.4	0.5	0.4	0.4
	lb/hr	2.2	3.9	4.9	3.7	**3.7**
	TPY[1]	9.7	17.1	21.6	16.0	16.1
	TPY[2]	8.1	14.8	21.5	5.0	12.4
	Load %			91.0	56.9	74.0

Notes:

1 The Tons Per Year value is calculated off of 8760 hours of operation, and represent expected worse case emissions.

2 The Tons Per Year value is calculated off of recorded hours of operation, representing actual emissions.

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer: Transwestern	Engine Model: MARS 90-13000S CS/MD 59F MATCH
Job ID: Station 7	
Inquiry Number:	Fuel Type: SD NATURAL GAS / Water Injection: NO
Run By: Jose Guillen / Date Run: 10-Aug-23	Engine Emissions Data: REV. 1.0

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
1 — 10850 HP 100.0% Load — Elev. 6900 ft — Rel. Humidity 60.0% — Temperature 20.0 Deg. F			
PPMvd at 15% O2	15.00	25.00	25.00
ton/yr	22.37	22.70	13.00
lbm/MMBtu (Fuel LHV)	0.060	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.63	0.64	0.37
lbm/hr	5.11	5.18	2.97
2 — 10373 HP 100.0% Load — Elev. 6900 ft — Rel. Humidity 60.0% — Temperature 40.0 Deg. F			
PPMvd at 15% O2	15.00	25.00	25.00
ton/yr	21.49	21.80	12.49
lbm/MMBtu (Fuel LHV)	0.060	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.63	0.64	0.37
lbm/hr	4.91	4.98	2.85
3 — 9621 HP 100.0% Load — Elev. 6900 ft — Rel. Humidity 60.0% — Temperature 60.0 Deg. F			
PPMvd at 15% O2	15.00	25.00	25.00
ton/yr	20.18	20.48	11.73
lbm/MMBtu (Fuel LHV)	0.060	0.060	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.64	0.65	0.37
lbm/hr	4.61	4.68	2.68

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

TWP - Roswell Compressor Station CS 4-Factor Analysis

TWP Roswell CS Equipment Amortization

8/10/2023

Annualized TCI - "A" Equation

$$A = P\frac{r(1+r)^n}{(1+r)^n - 1}$$

Assumed Discount Rate - "r" 8.00% Prime rate as of 8/6/2020

Cooper Bessemer LSV-16SSG, Unit 903, 4500 hp

Low Emission Controls

Total Capital Outlay (TCI) for control equip (each) - "P"	$	5,024,250	
Life Expectancy of control equip (years) - "n"		20	
Annualized TCI - "A"	$	511,730.96	
Annual O&M Costs	$	313,500	Based on 2023 year to date (January - June) O&M costs.
Total Annual Costs	$	825,231	
Baseline NOx Emissions (tpy)		312.3	Calculated using 2019-2022 testing results average and average hours of operation.
NOx Emissions with LEC (tpy)		103.2	Based on vendor guarantee of 2.5 g/hp-hr, and 2019-2022 average operating hours.
Emissions Reduction (tpy)		209.0	
% Reduction		66.9%	
Cost: 2019 $/yr-ton	$	3,948	

Electric Replacement

Total Capital Outlay (TCI) for control equip (each) - "P"	$	15,350,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	1,437,969	
Annual O&M Costs	$	1,900,000	Includes utilities and O&M costs. Based on 2023 YTD costs.
Total Annual Costs	$	3,337,969	
Baseline NOx Emissions (tpy)		312.3	Calculated using 2019-2022 testing results average and average hours of operation.
NOx Emissions with electric replacement (tpy)		0	
Emissions Reduction (tpy)		312.3	
% Reduction		100.0%	
Cost: $/yr-ton	$	10,689	(this value confirms the Permittee's calculation)

Cooper Bessemer LSV-16SSG, Unit 904, 4500 hp			
Low Emission Controls			
Total Capital Outlay (TCI) for control equip (each) - "P"	$	5,024,250	
Life Expectancy of control equip (years) - "n"		20	
Annualized TCI - "A"	$	511,731	
Annual O&M Costs	$	313,500	Based on 2023 year to date (January - June) O&M costs.
Total Annual Costs	$	825,231	
Baseline NOx Emissions (tpy)		115.6	Calculated using 2019-2022 testing results average and average hours of operation.
NOx Emissions with LEC (tpy)		97.5	Based on vendor guarantee of 2.5 g/hp-hr, and 2019-2022 average operating hours.
Emissions Reduction (tpy)		18.1	
% Reduction		15.6%	
Cost: $/yr-ton	$	45,658	
Electric Replacement			
Total Capital Outlay (TCI) for control equip (each) - "P"	$	15,350,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	1,437,969	
Annual O&M Costs	$	1,900,000	Includes utilities and O&M costs. Based on 2023 YTD costs.
Total Annual Costs	$	3,337,969	
Baseline NOx Emissions (tpy)		115.6	Calculated using 2019-2022 testing results average and average hours of operation.
NOx Emissions with electric replacement (tpy)		0	
Emissions Reduction (tpy)		115.61	
% Reduction		100.0%	
Cost: $/yr-ton	$	28,873	

$$A = P\frac{r(1+r)^n}{(1+r)^n - 1}$$

Units 903 & 904 (4500 hp units) Replaced by One (1) Solar Mars 100 Turbine			
Replacement w/ Gas Fired Turbine			
Total Capital Outlay (TCI) for control equip (each) - "P"	$	32,100,000	
Life Expectancy of control equip (years) - "n"		25	
Annualized TCI - "A"	$	3,007,088.81	
Annual O&M Costs	$	143,000	Based on 2022 O&M costs at TW's similar turbine facility.
Total Annual Costs	$	3,150,089	
Baseline NOx Emissions (tpy)		427.9	Sum total 903 + 904. Calculated using 2019-2022 testing results average and average hrs of operation.
NOx Emissions with turbine installation (tpy)		29.03	Based on vendor emissions sheet for proposed unit.
Emissions Reduction (tpy)		398.85	
% Reduction		93.2%	
Cost: 2019 $/yr-ton	$	7,898	

$$A = P\frac{r(1+r)^n}{(1+r)^n - 1}$$

LSV-16SG Model – 4 Cycle Scope of Supply Solution

- **Properly sized turbocharger, support systems and mounting hardware**
- **Aftercooling system (on engine)**
- **New cylinder heads with pre-combustion chambers with support system**
- **New constant pressure exhaust manifold**
- **ePCC™ System**
- **All engineering installation and commissioning of supplied systems**
- **Supplemental assemble drawings/BOM for new material only**
- **Post Commissioning Support**

AT RISK ITEMS NOT INCLUDED IN SCOPE

- Additional cooling capacity
- Compressed air capacity to handle turbocharger jet-assist during start-up
- High port power cylinders -GMW units (existing cylinders can be ground if not already converted)
- Ignition system must be CPU-2000 or comparable
- Control system upgrades
- Intake air silencer/filter
- Exhaust piping/silencer

$3,100,00 per unit for core LEC upgrade work
30% ($930,000) added for project at risk items

$4,000,000 estimate per unit for LEC

TW Station 9 Gearbox Estimate

Gearbox – Lufkin
$450,000 each / $900,000 total for qty 2 units

Labor
$117,000 total each / $235,000 for qty 2 units
Includes grout, per diem, travel, equipment

Total: $1,135,000 for Gearbox installation

Total Station 9 Upgrade to LEC

$9,135,000 Total
$10,048,500 Total with 10% contingency

$5,024,250 per Unit

Note: This cost estimate is based on a current quote from Cooper for the LEC upgrades, and previous project estimates prepared for the gearbox replacemenet (adjusted for inflation to current dollars).

Electrification of Units 903 & 904

1) 2x: 5000 HP electric motor, VFD, compressor package, couplings, etc.
2) Foundation pouring and leveling, compressor building, PCR building, station piping, gas cooling
3) Electrical work- conduit/cable install to PCR, VFD, motor, gearbox, control room, etc.
4) Contract and General Labor

-- Construction would have to occur adjacent to existing compression. Units 903 and 904 cannot be taken out of service for the replacement. Current firm shipping contracts require full utilization of compression horsepower at Roswell CS. This would requrie constructing significant amounts of new infrastructure, not allowing the use of some existing piping, buildings, foundations, coolers, etc..

-- Unknowns- Substation upgrade, transmission line upgrade, utility rate increases

- These items would have to be supplied by the local utility. Attempts have been made to attain estimates from utility for station upgrade, without success. The substation upgrade would require an engineering and load study, which itself could result in extended lead times before any decision on technical feasibility.

Total Station 9 Electrification Capital Cost

$30,700,000 **Total for station. Includes only items 1-4 above. Cost of third party infrastructure (i.e., substation, transmission line, etc.) and utility cost increases would be in addition to this.**

$15,350,000 **Per unit for electrification.**

Note: This cost estimate is based on previous electrification projects at Transwestern's Roswell Compressor Station (Unit 901 & 902) and Klagetoh Compressor Station. Both projects were replacements of existing RICE units (similar to units 903 & 904) with electric motors. The project costs were carried forward and adjusted for inflation into current dollars. Given the complex nature of this project and reliance on third parties to provide for and conduct a significant amount of the work (i.e., installation of infrastructure outside of the facility), Transwestern was unable to compile a thorough Request For Proposal. Given the short response period allowed, no vendor proposals were received.

Station 9 Utility Cost & OM Estimate

Installation of two additional electric units is expected to double the utility expenses at the station. This assumes the local power provider is able to supply the necessary load to operate the unit, and the rate does not significantly increase for the additional demand.

$91,000 **Projected Annual O&M Cost per unit (based of 2023 YTD expenses).**
$1,788,000 **Projected Annual Utility Cost per unit (based of 2023 YTD expenses).**

$1,900,000 **Projected total O&M plus utility cost, per unit (based on 2023 YTD expenses).**

Replacement of Units 903 & 904 w/ Solar Mars 100 Turbine

1) Purchase one (1) Solar Mars 100 turbine driven gas compressor package.
2) Foundation pouring and leveling, compressor building, PCR building, station piping, gas cooling
3) Electrical work- conduit/cable install to PCR, VFD, motor, gearbox, control room, etc.
4) Contract and General Labor
5) Requires station control system upgrade for new unit.

-- Construction would have to occur adjacent to existing compression. Units 903 and 904 cannot be taken out of service for the replacement. Current firm shipping contracts require full utilization of compression horsepower at Roswell CS. This would requrie constructing significant amounts of new infrastructure, not allowing the use of some existing piping, buildings, foundations, coolers, etc..

Total Station 9 Turbine Installation Capital Cost

$32,100,000 Total for station. Includes only items 1-5 above.

Note: This cost estimate is based on previously prepared project proposal for an installation of a turbine at Roswell Compressor Station. It should reflect the current cost of the project if completed today. Solar Turbines has instructed TW to anticipate a minimum of 6% cost increase per year for their products. The price increases on labor and other non Solar supplied materials are expected to be similar if not greater.

Station 9 Turbine O&M Estimate

The O&M cost of the turbines has been based on projected costs for other Transwestern stations operating similar (not identical) Solar turbines.

$143,000 Projected total O&M plus utility cost, per unit (based on 2022 expenses at similar station).

	Current Permitted NOx Values	Proposed LEC NOx Values
g/hp-hr	12.6	2.50
lb/hr	125	24.80
TPY[1]	547.5	108.63

Unit	Annual Operating Hours 2019	2020	2021	2022		4-yr Avg
903	8079.4	8696.3	8217.4	8303.8		8324.2
904	6651.5	8489.7	7843.5	8476.5		7865.3
Total:	14730.9	17186.0	16060.9	16780.3		16189.5
% of 2016 Total Hours	322%	375%	351%	366%		

Unit		NOx Test Values 2019	2020	2021	2022	4-yr Avg
903	g/hp-hr	5.6	8.5	10.6	5.5	7.6
	lb/hr	55.5	84.2	105.4	55.0	**75.0**
	TPY[1]	242.9	368.9	461.8	240.9	328.6
	TPY[2]	224.0	366.2	433.2	228.3	312.9
	Load %	88.7	74.3	88.0	85.6	84.1
904	g/hp-hr	2.4	1.4	2.7	5.4	3.0
	lb/hr	23.6	13.8	26.9	53.3	**29.4**
	TPY[1]	103.4	60.2	118.0	233.5	128.8
	TPY[2]	78.5	58.4	105.6	225.9	117.1
	Load %	89.1	71.6	87.4	87.8	84.0

Notes:

1 The Tons Per Year value is calculated off of 8760 hours of operation, and represent expected worse case emissions.

2 The Tons Per Year value is calculated off of recorded hours of operation, representing actual emissions.

Unit	Reported Annual Emissions (TPY) 2019	2020	2021	2022	4-yr Avg
903	224.0	366.2	433.2	228.3	312.9
904	212.6	58.4	105.6	225.9	150.6

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer: Transwestern	Engine Model: MARS 100-16000S CS/MD STANDARD
Job ID: Station 9	
Inquiry Number:	Fuel Type: SD NATURAL GAS / Water Injection: NO
Run By: Jose Guillen / Date Run: 10-Aug-23	Engine Emissions Data: REV. 1.0

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
1 — 14537 HP 100.0% Load — Elev. 3600 ft — Rel. Humidity 60.0% — Temperature 20.0 Deg. F			
PPMvd at 15% O2	15.00	25.00	25.00
ton/yr	29.03	29.46	16.87
lbm/MMBtu (Fuel LHV)	0.060	0.061	0.035
lbm/(MW-hr)	0.61	0.62	0.36
(gas turbine shaft pwr) lbm/hr	6.63	6.73	3.85
2 — 13940 HP 100.0% Load — Elev. 3600 ft — Rel. Humidity 60.0% — Temperature 40.0 Deg. F			
PPMvd at 15% O2	15.00	25.00	25.00
ton/yr	27.93	28.34	16.23
lbm/MMBtu (Fuel LHV)	0.060	0.061	0.035
lbm/(MW-hr)	0.61	0.62	0.36
(gas turbine shaft pwr) lbm/hr	6.38	6.47	3.71
3 — 13199 HP 100.0% Load — Elev. 3600 ft — Rel. Humidity 60.0% — Temperature 60.0 Deg. F			
PPMvd at 15% O2	15.00	25.00	25.00
ton/yr	26.67	27.07	15.50
lbm/MMBtu (Fuel LHV)	0.060	0.061	0.035
lbm/(MW-hr)	0.62	0.63	0.36
(gas turbine shaft pwr) lbm/hr	6.09	6.18	3.54

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Attachment C:

Supplemental Information For Cost Evaluations

Egan, Kerry L

From: Stork, Matthew
Sent: Friday, August 11, 2023 11:21 AM
To: Egan, Kerry L
Subject: RE: RE: Revived Four Factor Analysis Requests - Follow up

Kerry,

See below, this is very preliminary, but should work for this discussion. Expect cost to increase by end of year due to Good Neighbor Rule demand.

All LEC/controls/gear box numbers are preliminary. There have not been any site visits made to firm up costs, which are subject to change.

- **LSV-16SG Model – 4 Cycle Scope of Supply Solution**
  - **• Properly sized turbocharger, support systems and mounting hardware**
  - **• Aftercooling system (on engine)**
  - **• New cylinder heads with pre-combustion chambers with support system**
  - **• New constant pressure exhaust manifold**
  - **• ePCC™ System**
  - **• All engineering installation and commissioning of supplied systems**
  - **• Supplemental assemble drawings/BOM for new material only**
  - **• Post Commissioning Support**
    - **AT RISK ITEMS NOT INCLUDED IN SCOPE**
      - • Additional cooling capacity
      - • Compressed air capacity to handle turbocharger jet-assist during start-up
      - • High port power cylinders -GMW units (existing cylinders can be ground if not already converted)
      - • Ignition system must be CPU-2000 or comparable
      - • Control system upgrades
      - • Intake air silencer/filter
      - • Exhaust piping/silencer
    - **$3,100,00 per unit**
    - **30% adder for project at risk items**
    - **$4,000,000 estimate per unit for LEC**

- **TW Station 7 Controls Upgrade**
  - **Upgrade existing controls to Allen Bradley from obsolete OPTO**
  - **$1,000,000**

- **TW Station 7 Gearbox Estimate**
  - **Gearbox – Lufkin**
    - **$450,000 each**

        - **$1,350,000 total for qty 3 units**
    - **Labor**
        - **$350,000 total**
            - **Includes grout, per diem, travel, equipment**
    - **Spare Gear Set**
        - **$230,000**
            - **With gear and shaft assembly, bearings, seals, gaskets, ect.**
    - **Total**
        - **$1,870,000 with 10% contingency**
        - **$230,000 spare gear set**
- **Total Station 7 Qty 3 Cooper Bessemer LSV 16SG LEC package**
    - **$14,870,000 Total**
    - **$16,357,000 Total with 10% contingency**

From: Egan, Kerry L <kerry.egan@energytransfer.com>
Sent: Tuesday, August 1, 2023 4:14 PM
To: Clay, Collin <Collin.Clay@energytransfer.com>; Mayer, George <George.Mayer@energytransfer.com>; Lopez, Jafet E. <Jafet.Lopez@energytransfer.com>; McDonald, Tyler <Tyler.McDonald@energytransfer.com>; Stork, Matthew <Matthew.Stork@energytransfer.com>; Miro, Alena M. <alena.miro@energytransfer.com>; Roybal, David E. <David.Roybal@energytransfer.com>; Jolly, Dustin <Dustin.Jolly@energytransfer.com>
Subject: RE: Revived Four Factor Analysis Requests - Follow up

Good afternoon,

I know I've already talked with several of you about this, but I wanted to send out a note, so everyone is on the same page. Sorry for the long email…

After our last call, I did follow up with the NMED regarding the suitability of the Cooper LEC technology. Unfortunately, we did not get the blanket approval to eliminate that option from the 4FA. According to NMED we must consider all technically feasible options to complete the 4FA. We are going to need numbers for the LEC modification.
In our narrative description of the 4FA we will make it clear that for Roswell we would not be installing these due to the more stringent requirements of the Ozone Precursor. I fully expect NMED will be accepting of this claim.
For Station #7 we're not able to make that claim, since it is not subject to the Ozone Precursor Rule. Although we can clarify the issues we're having with procuring the materials/parts to continue and the serious concerns we have with the ability to operate the units.

Matt is helping get updated costs from Cooper for the LEC upgrade.

If we are going assert this retrofit requires a replacement of the western gearbox, and/or any work on the compressor itself (or other attached equipment), to ensure long term operational viability of the unit, I think we can. We need to include those costs in capital outlay figure. We'll have to provide supporting documentation for the cost and justification in the narrative as to why this work would be required.
The same would hold true for the electrification option. If a new gear box and compressor are needed, let's capture those costs.

George/Collin, I believe you mentioned you'd be able to help provide these numbers based on quotes we had for a potential job at WT-1. Is that correct?
We're still needing the updated numbers for the electrification option. If you can put something together on that front it would be greatly appreciated.

Jafet/Tyler, I just wanted to verify that we are working on getting the numbers for the replacement together. If you have that send it my way when you can.

Remaining Action Items:

- Finalize quotes for LEC upgrade. Cooper's portion only.
- Determine full extent of equipment replacement/modification required for the LEC.
    - Provide numbers and supporting docs for necessary work to facilitate LEC upgrade (i.e., gear box replacement, etc.)
- Finalize updated electrification costs.
    - Include the costs for any necessary accessory work (i.e., gear box replacement, etc.)
- Finalize turbine replacement costs.

I've got to have everything put together in our response package by EOB on 8/11, so I'm hoping we can have all of the numbers back by 8/9 at the latest. That should give me some time to get everything compiled.

Please let me know what you think and if you have any questions for me.
I greatly appreciate the help (and patience!!).

Thanks,

ENERGY TRANSFER
Moving America's Energy

Mr. Kerry Egan
Sr. Environmental Specialist
Energy Transfer Company

O: 505-260-4023
C: 575-808-9402

8501 Jefferson St NE
Albuquerque, NM 87113

Egan, Kerry L

From: Mayer, George
Sent: Wednesday, August 9, 2023 2:24 PM
To: Egan, Kerry L; Clay, Collin; Lopez, Jafet E.; McDonald, Tyler; Miro, Alena M.; Roybal, David E.; Jolly, Dustin
Cc: Thomas, Eddie; Modgling, Guy
Subject: Electrification Costs- Four Factor Analysis

Kerry,
From my memory the 2019 electrification costs were a small adjustment using basic inflation numbers and some adjustments for pricing differences. This is not sufficient for what we truly believe the cost would be to electrify Units 903 and 904 as well as Station 7. Below is a breakdown of what the costs would more closely relate to. I will say that we still have quite a few unknowns based on the limited timing to get these costs together. We have not received an answer from either utility at Station 9 or 7 whether they would be able to support additional load or what costs would be required to upgrade their system in order to do so. I've included those as unknowns below.

Station 9
Electrification would include installing two new electric 5,000 HP units. Based on our current pipeline conditions we are sold out moving west out of Roswell. We therefore cannot afford to simply replace units 903 and 904 and have 6-9 months of limited capacity while the LSVs get pulled out and replaced. There are also additional costs to keeping the existing gearboxes as Matt covered in his estimate.

Costs include:

- 2x: 5000 HP electric motor, VFD, compressor package, couplings, etc.
- Foundation pouring and leveling, compressor building, PCR building, station piping, gas cooling
- Electrical work- conduit/cable install to PCR, VFD, motor, gearbox, control room, etc.
- Contract and General Labor
- Unknowns- Substation upgrade, transmission line upgrade, utility rate increases

Total Build Cost: $30.7M + Unknowns
Annual Utility Cost: $6.3M (an additional $3.2M)

- This assumes a similar load for the additional units and no changes to Central Valley Co-op's pricing.

Station 7:
This cost includes a full renovation of the station including a brand new compressor building, new units, substation, and roughly 8 miles of power line infrastructure to connect to PNM. Similar to Station 9 we do not have the ability to replace existing units and operate at limited capacity during planned construction. Instead we would build new facilities within the current station and switch over operation once construction is complete.

Costs include:

- 2x: 7,500 HP Electric motor, VFD, compressor package, couplings, etc.
- Foundation pouring and leveling, compressor building, PCR building, station piping, gas cooling
- Electrical work- conduit/cable install to PCR, VFD, motor, gearbox, control room, etc.
- Contract and General Labor
- Unknowns- Substation build, 8 miles of 69kv or 115kv transmission line, utility costs.

TOTal Build Cost: $36M + Unknowns

- This cost is similar to our East Mainline modernization project estimates

Annual Utility cost: $5.3 million

- Based on PNM Large Power Service Rates

ENERGY TRANSFER

George Mayer
Senior Planning Engineer
Interstate Business Development
1300 Main St. | O: (713) 989-2429
Houston, TX 77002 C: (325) 212-7246

ENERGY TRANSFER

Appropriation Request

ORIGINAL:- X REVISION:-

Project Name: TW Modernization Station 7

County: Torrance **State:** NM **Tax Jurisdiction code** USNM8702000161

Multi-county breakdown: County:_____ %___ County:_____ %___ County:_____ %___

Today's Date: 8/9/2023
Est Start Date/Basic Start : 9/1/2025
Constr Start Date: 6/1/2026
Constr End Date: 12/31/2026
Est In Svc Date: 11/1/2026
Est Compl Date: 12/31/2026
Est Compl Rpt Date/Basic End : 5/1/2027

Major Location / Asset Location / Functional Class: Required for Interstate Gas (FERC-regulated) companies only

Major Location: *1424 |NM - COMPRESSION*

Profit Center and Asset Location Correlation

Previously selected Profit Center P260510000

Asset Location: *1010294 |P260510000 - NM - STATION NO.7*

Functional Class: Gas Transmission Plant

Description: Engineer, design, procure, construct and commission the horsepower replacement of two existing compressor units with (2) two new Solar Turbines Mars 90 gas compressor packages totaling 26,440hp and all ancillary equipment including PCR building, fuel gas skid, seal conditioning, air compressor system, controls system upgrade, utility tankage, blowdown silencers, power generation, etc.

Pipe: _____ ft. Dia: _____ in. WT: _____ in. Type _____ Coating:
Pipe: _____ ft. Dia: _____ in. WT: _____ in. Type _____ Coating:

ONLY FOR HPL ASSETS: Acct. Loc. No. _____ ☐ Leased ☐ Owned

Account No.			Description	Estimated Cost		FOR INTERSTATE GAS ONLY	
						Enter % split for Retirement (total CWIP and RWIP must equal 100%)	
						100%	
Legacy SXL	Legacy ETP	S4		Purchase	Total	CWIP	RWIP
	5651248	563110	CAP-SOFTWARE	$ -	$ -	$ -	
	5655003	563120	CAP-COMPUTERS	$ -	$ -	$ -	
	5651247	563200	CAP-HARDWARE	$ -	$ -	$ -	
	5651117	563260	COMM TOWER & CIRCUIT LEASE	$ 16,238	$ 16,238	$ 16,238	
	5651410	563334	TELEMETRY - COMMUNICATIONS	$ 59,538	$ 59,538	$ 59,538	
	5651600	563920	UTILITIES	$ -	$ -	$ -	
	5651220	564000	PRESSURE VESSELS	$ 2,186,650	$ 2,186,650	$ 2,186,650	
	5651225	564001	COOLING TOWERS	$ -	$ -	$ -	
	5651230	564002	COMPRESSORS	$ 18,402,500	$ 18,402,500	$ 18,402,500	
	5651245	564003	BUILDING-OFFICE	$ -	$ -	$ -	
	New	564008	BUILDING-NON-OFFICE	$ 1,353,125	$ 1,353,125	$ 1,353,125	
	5651250	564004	SKID PACKAGE	$ 194,850	$ 194,850	$ 194,850	
	5651255	564005	CRYO PLANTS	$ -	$ -	$ -	
	5651260	564006	PUMPS	$ -	$ -	$ -	
	5651261	564007	DEHYDRATION & TREATING	$ -	$ -	$ -	
	5651271	564009	HEAT EXCHANGERS	$ -	$ -	$ -	
	5651272	564010	BOILERS	$ -	$ -	$ -	
	5651280	564012	STORAGE TANKS	$ 216,500	$ 216,500	$ 216,500	
	5651291	564013	LAUNCHERS/RECEIVERS	$ -	$ -	$ -	
	5651420	564015	CATHODIC PROTECTION	$ -	$ -	$ -	
	5651510	564016	PIPE	$ 898,475	$ 898,475	$ 898,475	
507103	5651530	564017	FITTINGS, VALVES & INSTRUMENTS	$ 1,786,125	$ 1,786,125	$ 1,786,125	
	5651540	564018	CHEMICALS, OILS, LUBE, FUELS	$ 108,250	$ 108,250	$ 108,250	
	5651550	564019	PROTECTIVE COATINGS	$ -	$ -	$ -	
	5651560	564020	ELECTRICAL MATERIALS	$ 1,353,125	$ 1,353,125	$ 1,353,125	
	5651570	564021	INSTRUMENTATION	$ 663,031	$ 663,031	$ 663,031	
	5651580	564022	FOUNDATION, FENCING & SUPPORTS	$ 66,625	$ 66,625	$ 66,625	
	5652100	564023	AMINE PLANTS	$ -	$ -	$ -	
	5652300	564025	ENGINES	$ -	$ -	$ -	
	5652500	564026	GENERATOR	$ 811,875	$ 811,875	$ 811,875	
	5652600	564027	THERMAL OXIDIZER	$ -	$ -	$ -	
	5652900	564028	CAP-MISC EQUIP/COMPONENTS	$ -	$ -	$ -	
	5651270	564100	FIRED EQUIPMENT	$ 189,438	$ 189,438	$ 189,438	
	5651273	564101	PROCESS EQUIPMENT	$ -	$ -	$ -	
	5651311	564102	MEASUREMENT EQUIPMENT	$ 32,475	$ 32,475	$ 32,475	
	5651610	564103	RENTAL EQUIPMENT	$ -	$ -	$ -	
	5651620	564104	SAFETY EQUIPMENT	$ 10,825	$ 10,825	$ 10,825	
	New	564111	DOCK EQUIPMENT	$ -	$ -	$ -	
	New	564112	LOADING ARMS	$ -	$ -	$ -	
	New	564113	DOCK STRUCTURE	$ -	$ -	$ -	
507104	5651851	565100	CONTRACT LABOR	$ 8,489,063	$ 8,489,063	$ 8,489,063	$ -
	5651857	565101	ELECTRICAL LABOR	$ 3,218,750	$ 3,218,750	$ 3,218,750	$ -
	5651858	565102	MACHINE HIRE-WELDING	$ -	$ -	$ -	
	5651859	565103	EXTRA LABOR	$ -	$ -	$ -	$ -
	5651861	565104	X-RAY	$ 187,500	$ 187,500	$ 187,500	$ -
	5651862	565105	DRAFTING	$ 25,000	$ 25,000	$ 25,000	$ -
	5651863	565106	INSPECTION - MILL/SHOP	$ 25,000	$ 25,000	$ 25,000	
	5651864	565107	INSPECTION - CONSTRUCTION	$ 783,750	$ 783,750	$ 783,750	$ -
	5651880	565108	SURVEY	$ 25,000	$ 25,000	$ 25,000	$ -
507106	5651883	565109	CONSULTING & ENGINEERING	$ 780,000	$ 780,000	$ 780,000	$ -
	5651885	565110	LEGAL SERVICES	$ -	$ -	$ -	$ -
	5651886	565111	ENVIRONMENTAL	$ -	$ -	$ -	$ -
	5651890	565113	PERMITTING	$ 250,000	$ 250,000	$ 250,000	$ -
	5651590	565118	ROADS & LANDSCAPING	$ 312,500	$ 312,500	$ 312,500	
507107	5651110	569100	RIGHT OF WAY RODDAGE	$ -	$ -	$ -	
	5651120	569110	RIGHT OF WAY DAMAGES	$ -	$ -	$ -	
	5651130	569120	RIGHT OF WAY SPECIFIC DAMAGES	$ -	$ -	$ -	
	5651881	569130	RIGHT-OF-WAY RESTORATION	$ -	$ -	$ -	
	5651882	569140	RIGHT-OF-WAY AGENTS	$ -	$ -	$ -	
	5651140	569200	CONDEMNATION DEPOSIT	$ -	$ -	$ -	
	5651115	569210	EASEMENTS/LEASES - SURFACE SITES	$ -	$ -	$ -	
	5651240	569220	LAND PURCHASES	$ -	$ -	$ -	
			SUB-TOTAL	$ 42,446,206	$ 42,446,206	$ 42,446,206	$ -
	5651920	565115	FREIGHT	$ 595,045	$ 595,045	$ 595,045	
507105	5651950	569900	MISCELLANEOUS	$ 541,250	$ 541,250	$ 541,250	
	5651246	562000	VEHICLES	$ -	$ -	$ -	
507101	5651970	562165	STAFF EXP (OTHER THAN M&E)	$ 20,000	$ 20,000	$ 20,000	$ -
	5651971	562160	STAFF EXP (M&E)	$ 2,500	$ 2,500	$ 2,500	$ -
507102	5651972	561120	LABOR- DIRECT	$ 75,000	$ 75,000	$ 75,000	$ -
	5651974	561140	LABOR- PAYROLL TAXES	$ 6,750	$ 6,750	$ 6,750	$ -
	5651975	561110	LABOR- BENEFITS	$ 13,500	$ 13,500	$ 13,500	$ -
	5651884	569905	CIAC AID-IN-CONSTRUCTION - TAXABLE-BILLED	$ -	$ -	$ -	
	5651887	565112	WARRANTY & BILLABLE REPAIRS	$ -	$ -	$ -	
	5651888	569902	LINE PACK	$ -	$ -	$ -	
	5659000	569906	OTHER CAPITAL PROJECTS	$ -	$ -	$ -	
	5659990	569940	CONTINGENCY	$ 2,525,500	$ 2,525,500	$ 2,525,500	
			TOTAL (EXCLUDING Overhead/Tax Gross-Up/AFUDC)	$ 46,225,752	$ 46,225,752	$ 46,225,752	$ -

Contacts:
☑ Project Manager — Tyler McDonald
☐ Analyst
☐ Commercial Rep — *(for growth or PLI projects)*

Notes:

Complete box below if Interstate Gas project has a partial RWIP component

The _____ RWIP derivation results in a $ - estimate, which the project manager believes to be a reasonable estimate of the value of the cost of removal of the asset(s) referenced in the project scope. The estimate takes into consideration the following:

DESCRIPTION OF ASPECTS SPECIFIC TO REMOVAL WORK AND ANY NOTEWORTHY CIRCUMSTANCES UNDER WHICH THE WORK WILL BE PERFORMED

Enter text here

For Commercial use only:		Percentage
Project Cost	$ 46,225,752	
Overhead	$ -	
Tax Gross-Up	$ -	
AFUDC	$ -	
Gas Loss	$ -	
Total Cost	$ 46,225,752	

TOTAL (INCLUDING Overhead/Tax Gross-Up/AFUDC)

The latest version of this form can be accessed on the Intranet under Department - Energy Transfer - Cost Controls - Forms.

ENERGY TRANSFER

Appropriation Request

ORIGINAL:- X REVISION:-

Project Name: TW Modernization Station 9

County: Chaves **State:** NM **Tax Jurisdiction code** USNM8702000161

Multi-county breakdown: County:_____ %___ County:_____ %___ County:_____ %___

Today's Date:	8/9/2023
Est Start Date/Basic Start :	9/1/2025
Constr Start Date:	6/1/2026
Constr End Date:	12/31/2026
Est In Svc Date:	11/1/2026
Est Compl Date:	12/31/2026
Est Compl Rpt Date/Basic End :	5/1/2027

Major Location / Asset Location / Functional Class: Required for Interstate Gas (FERC-regulated) companies only

Major Location: *1424 |NM - COMPRESSION*

Profit Center and Asset Location Correlation

Previously selected Profit Center P260510000

Asset Location: *1010296 |P260510000 - NM - STATION NO.9*

Functional Class: Gas Transmission Plant

Description: Engineer, design, procure, construct and commission the horsepower replacement of existing compressor units with (1) one new Solar Turbines Mars 100 gas compressor packages totaling 15,900hp and all ancillary equipment including PCR building, fuel gas skid, seal conditioning, air compressor system, controls system upgrade, utility tankage, blowdown silencers, compressor restaging, etc.

Pipe: _____ ft. Dia: _____ in. WT: _____ in. Type _____ Coating:
Pipe: _____ ft. Dia: _____ in. WT: _____ in. Type _____ Coating:

ONLY FOR HPL ASSETS: Acct. Loc. No. _____ ☐ Leased ☐ Owned

Account No.			Description	Estimated Cost		FOR INTERSTATE GAS ONLY	
						Enter % split for Retirement (total CWIP and RWIP must equal 100%)	
						100%	
Legacy SXL	Legacy ETP	S4		Purchase	Total	CWIP	RWIP
	5651248	563110	CAP-SOFTWARE	$ -	$ -	$ -	
	5655003	563120	CAP-COMPUTERS	$ -	$ -	$ -	
	5651247	563200	CAP-HARDWARE	$ -	$ -	$ -	
	5651117	563260	COMM TOWER & CIRCUIT LEASE	$ 16,238	$ 16,238	$ 16,238	
	5651410	563334	TELEMETRY - COMMUNICATIONS	$ 59,538	$ 59,538	$ 59,538	
	5651600	563920	UTILITIES	$ -	$ -	$ -	
	5651220	564000	PRESSURE VESSELS	$ 1,769,888	$ 1,769,888	$ 1,769,888	
	5651225	564001	COOLING TOWERS	$ -	$ -	$ -	
	5651230	564002	COMPRESSORS	$ 12,124,000	$ 12,124,000	$ 12,124,000	
	5651245	564003	BUILDING-OFFICE	$ -	$ -	$ -	
	New	564008	BUILDING-NON-OFFICE	$ 920,125	$ 920,125	$ 920,125	
	5651250	564004	SKID PACKAGE	$ 194,850	$ 194,850	$ 194,850	
	5651255	564005	CRYO PLANTS	$ -	$ -	$ -	
	5651260	564006	PUMPS	$ -	$ -	$ -	
	5651261	564007	DEHYDRATION & TREATING	$ -	$ -	$ -	
	5651271	564009	HEAT EXCHANGERS	$ -	$ -	$ -	
	5651272	564010	BOILERS	$ -	$ -	$ -	
	5651280	564012	STORAGE TANKS	$ 216,500	$ 216,500	$ 216,500	
	5651291	564013	LAUNCHERS/RECEIVERS	$ -	$ -	$ -	
	5651420	564015	CATHODIC PROTECTION	$ -	$ -	$ -	
	5651510	564016	PIPE	$ 573,725	$ 573,725	$ 573,725	
507103	5651530	564017	FITTINGS, VALVES & INSTRUMENTS	$ 1,125,800	$ 1,125,800	$ 1,125,800	
	5651540	564018	CHEMICALS, OILS, LUBE, FUELS	$ 54,125	$ 54,125	$ 54,125	
	5651550	564019	PROTECTIVE COATINGS	$ -	$ -	$ -	
	5651560	564020	ELECTRICAL MATERIALS	$ 1,228,638	$ 1,228,638	$ 1,228,638	
	5651570	564021	INSTRUMENTATION	$ 587,256	$ 587,256	$ 587,256	
	5651580	564022	FOUNDATION, FENCING & SUPPORTS	$ 33,313	$ 33,313	$ 33,313	
	5652100	564023	AMINE PLANTS	$ -	$ -	$ -	
	5652300	564025	ENGINES	$ -	$ -	$ -	
	5652500	564026	GENERATOR	$ -	$ -	$ -	
	5652600	564027	THERMAL OXIDIZER	$ -	$ -	$ -	
	5652900	564028	CAP-MISC EQUIP/COMPONENTS	$ -	$ -	$ -	
	5651270	564100	FIRED EQUIPMENT	$ 189,438	$ 189,438	$ 189,438	
	5651273	564101	PROCESS EQUIPMENT	$ -	$ -	$ -	
	5651311	564102	MEASUREMENT EQUIPMENT	$ 32,475	$ 32,475	$ 32,475	
	5651610	564103	RENTAL EQUIPMENT	$ -	$ -	$ -	
	5651620	564104	SAFETY EQUIPMENT	$ 10,825	$ 10,825	$ 10,825	
	New	564111	DOCK EQUIPMENT	$ -	$ -	$ -	
	New	564112	LOADING ARMS	$ -	$ -	$ -	
	New	564113	DOCK STRUCTURE	$ -	$ -	$ -	
507104	5651851	565100	CONTRACT LABOR	$ 5,303,125	$ 5,303,125	$ 5,303,125	$ -
	5651857	565101	ELECTRICAL LABOR	$ 2,593,750	$ 2,593,750	$ 2,593,750	$ -
	5651858	565102	MACHINE HIRE-WELDING	$ -	$ -	$ -	
	5651859	565103	EXTRA LABOR	$ -	$ -	$ -	$ -
	5651861	565104	X-RAY	$ 187,500	$ 187,500	$ 187,500	$ -
	5651862	565105	DRAFTING	$ 25,000	$ 25,000	$ 25,000	$ -
	5651863	565106	INSPECTION - MILL/SHOP	$ 25,000	$ 25,000	$ 25,000	
	5651864	565107	INSPECTION - CONSTRUCTION	$ 683,750	$ 683,750	$ 683,750	$ -
	5651880	565108	SURVEY	$ 25,000	$ 25,000	$ 25,000	$ -
507106	5651883	565109	CONSULTING & ENGINEERING	$ 780,000	$ 780,000	$ 780,000	$ -
	5651885	565110	LEGAL SERVICES	$ -	$ -	$ -	$ -
	5651886	565111	ENVIRONMENTAL	$ -	$ -	$ -	$ -
	5651890	565113	PERMITTING	$ 250,000	$ 250,000	$ 250,000	$ -
	5651590	565118	ROADS & LANDSCAPING	$ 312,500	$ 312,500	$ 312,500	
507107	5651110	569100	RIGHT OF WAY RODDAGE	$ -	$ -	$ -	
	5651120	569110	RIGHT OF WAY DAMAGES	$ -	$ -	$ -	
	5651130	569120	RIGHT OF WAY SPECIFIC DAMAGES	$ -	$ -	$ -	
	5651881	569130	RIGHT-OF-WAY RESTORATION	$ -	$ -	$ -	
	5651882	569140	RIGHT-OF-WAY AGENTS	$ -	$ -	$ -	
	5651140	569200	CONDEMNATION DEPOSIT	$ -	$ -	$ -	
	5651115	569210	EASEMENTS/LEASES - SURFACE SITES	$ -	$ -	$ -	
	5651240	569220	LAND PURCHASES	$ -	$ -	$ -	
			SUB-TOTAL	$ 29,322,356	$ 29,322,356	$ 29,322,356	$ -
	5651920	565115	FREIGHT	$ 406,166	$ 406,166	$ 406,166	
507105	5651950	569900	MISCELLANEOUS	$ 433,000	$ 433,000	$ 433,000	
	5651246	562000	VEHICLES	$ -	$ -	$ -	
507101	5651970	562165	STAFF EXP (OTHER THAN M&E)	$ 20,000	$ 20,000	$ 20,000	$ -
	5651971	562160	STAFF EXP (M&E)	$ 2,500	$ 2,500	$ 2,500	$ -
507102	5651972	561120	LABOR- DIRECT	$ 75,000	$ 75,000	$ 75,000	$ -
	5651974	561140	LABOR- PAYROLL TAXES	$ 6,750	$ 6,750	$ 6,750	$ -
	5651975	561110	LABOR- BENEFITS	$ 13,500	$ 13,500	$ 13,500	$ -
	5651884	569905	CIAC AID-IN-CONSTRUCTION - TAXABLE-BILLED	$ -	$ -	$ -	
	5651887	565112	WARRANTY & BILLABLE REPAIRS	$ -	$ -	$ -	
	5651888	569902	LINE PACK	$ -	$ -	$ -	
	5659000	569906	OTHER CAPITAL PROJECTS	$ -	$ -	$ -	
	5659990	569940	CONTINGENCY	$ 1,811,252	$ 1,811,252	$ 1,811,252	
			TOTAL (EXCLUDING Overhead/Tax Gross-Up/AFUDC)	$ 32,090,525	$ 32,090,525	$ 32,090,525	$ -

Contacts:
☑ Project Manager: Tyler McDonald
☐ Analyst: _____
☐ Commercial Rep: _____ *(for growth or PLI projects)*

Notes: _____

Complete box below if Interstate Gas project has a partial RWIP component

The _____ RWIP derivation results in a $ - estimate, which the project manager believes to be a reasonable estimate of the value of the cost of removal of the asset(s) referenced in the project scope. The estimate takes into consideration the following:

DESCRIPTION OF ASPECTS SPECIFIC TO REMOVAL WORK AND ANY NOTEWORTHY CIRCUMSTANCES UNDER WHICH THE WORK WILL BE PERFORMED

Enter text here

For Commercial use only:		Percentage
Project Cost	$ 32,090,525	
Overhead	$ -	
Tax Gross-Up	$ -	
AFUDC	$ -	
Gas Loss	$ -	
Total Cost	$ 32,090,525	

TOTAL (INCLUDING Overhead/Tax Gross-Up/AFUDC)

The latest version of this form can be accessed on the Intranet under Department - Energy Transfer - Cost Controls - Forms.

D.7 Harvest Four Corners

Supporting documentation for Harvest Four Corners is provided below. Facility-specific documentation is provided first, followed by documentation pertaining to multiple facilities and/or the owner/operator. The following documents are included in this section (in reading order):

- Kutz Canyon Processing Plant:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (11/2019)
    - Information Regarding Process & SSM Flaring (12/13/2019)
    - Follow-Up Submittal (3/2020)
    - Follow-Up Submittal (10/23/2020)
    - Follow-Up Submittal (2/26/2021)
    - Follow-Up Submittal (8/28/2023)
    - Follow-Up Submittal (2/22/2024)

NMED Final Cost Evaluation
Harvest Four Corners - Kutz Canyon Processing Plant

Facility Information

Harvest - Kutz Canyon PP	**Facility**
Six 1975 NG CT and two 1981 NG CT	**Units**
1, 2, 3, 4, 5, 6, 19, 20	**Unit IDs**
SCR	**Evaluated Pollution Control***
NA	**Target Emissions Rate (g NOx/bhp-hr)**

*This analysis assumes physical space is available for SCR. Harvest asserted physical space is not available.

Additional Information

2024	**Calendar year associated with cost estimates**
3830	**Nameplate Power Output (hp/unit, Units 1, 2 and 3)**
34.81	**Heat Input Capacity (MMBtu HHV) for Units 1, 2 and 3**
3016	**Nameplate Power Output (hp/unit, Units 19 and 20)**
27.41	**Heat Input Capacity (MMBtu HHV) for Units 19 and 20**

Economic Evaluation

Cost Component		Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6	Unit 19	Unit 20	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 2,571,614	$ 2,571,614	$ 2,571,614	$ 2,571,614	$ 2,571,614	$ 2,571,614	$ 2,201,603	$ 2,201,603	EPA SCR Tool (2024$)	
Interest Rate (%)	R	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	Harvest - Pricing Term Sheet (v8.28.23)	
Useful Life (yr)	Y	20	20	20	20	20	20	20	20	EPA Cost Manual	
Capital Recovery Factor	CRF	0.0981	0.0981	0.0981	0.0981	0.0981	0.0981	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 252,255	$ 252,255	$ 252,255	$ 252,255	$ 252,255	$ 252,255	$ 215,960	$ 215,960	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 39,732	$ 34,965	$ 32,095	$ 36,993	$ 36,995	$ 40,754	$ 27,583	$ 24,978	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 2,782	$ 2,782	$ 2,782	$ 2,782	$ 2,782	$ 2,782	$ 2,760	$ 2,760	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 294,770	$ 290,003	$ 287,133	$ 292,031	$ 292,033	$ 295,792	$ 246,303	$ 243,698	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	80%	80%	80%	80%	80%	80%	80%	80%	EPA SCR Tool	Consistent with EPA and industry documentation.
Baseline Actual NOx Emissions (ton/yr)	BAE	58.0	47.5	32.5	46.1	41.2	48.4	37.6	30.3	CY 2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	0%	0%	0%	0%	-	Not requested by Harvest
Projected Actual Emissions (ton/yr)	PAE	58.0	47.5	32.5	46.1	41.2	48.4	37.6	30.3	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	46.4	38.0	26.0	36.9	33.0	38.7	30.1	24.3	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 6,358**	**$ 7,626**	**$ 11,041**	**$ 7,919**	**$ 8,862**	**$ 7,643**	**$ 8,190**	**$ 10,040**	-	TAC/ER

NMED Final Cost Evaluation
Harvest Four Corners - Kutz Canyon Processing Plant

Facility Information

Harvest - Kutz Canyon PP	**Facility**
Six 1975 NG CT and two 1981 NG CT	**Units**
1, 2, 3, 4, 5, 6, 19, 20	**Unit IDs**
SoLoNOx	**Evaluated Pollution Control**
25	**Post Control NOx Emissions Rate (ppmdv)**

Additional Information

2020	**Calendar year associated with cost estimates**
3830	**Nameplate Power Output (hp/unit, Units 1, 2 and 3)**
34.81	**Heat Input Capacity (MMBtu HHV) for Units 1, 2 and 3**
3016	**Nameplate Power Output (hp/unit, Units 19 and 20)**
27.41	**Heat Input Capacity (MMBtu HHV) for Units 19 and 20**

Economic Evaluation

Cost Component		Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6	Unit 19	Unit 20	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 682,615	$ 682,615	$ 682,615	$ 682,615	$ 682,615	$ 682,615	$ 666,162	$ 666,162	Harvest Pricing 9.28.2020	SoloNOx and engine upgrades
Other Direct Capital Costs 1 ($)	ODC1	$ 235,676	$ 198,714	$ 198,714	$ 198,714	$ 198,714	$ 198,714	$ 249,034	$ 201,636	Harvest Pricing 9.28.2020	Controls upgrades
Other Direct Capital Costs 2 ($)	ODC2	$ 38,701	$ 38,701	$ 38,701	$ 38,701	$ 38,701	$ 38,701	$ 38,701	$ 38,701	Harvest Pricing 9.28.2020	Associated labor
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,852	Harvest Pricing 9.28.2020	Engine Lift Assembly for Unit 20 only
Total Capital Costs - Direct ($)	TCC	$ 956,992	$ 920,030	$ 920,030	$ 920,030	$ 920,030	$ 920,030	$ 953,897	$ 924,350	-	PEC + ODC1 + ODC2 + IDC
Additional Capital ($)	AC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Not specified by Harvest
Total Capital Investment ($)	TCI	$ 956,992	$ 920,030	$ 920,030	$ 920,030	$ 920,030	$ 920,030	$ 953,897	$ 924,350	-	TCC + AC
Interest Rate (%)	R	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	Harvest - Pricing Term Sheet (v8.28.23)	
Useful Life (yr)	Y	20	20	20	20	20	20	20	20	Harvest Initial FFA (11.2019)	
Capital Recovery Factor	CRF	0.0981	0.0981	0.0981	0.0981	0.0981	0.0981	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 93,873	$ 90,248	$ 90,248	$ 90,248	$ 90,248	$ 90,248	$ 93,570	$ 90,672	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 43,567	$ 43,567	$ 43,567	$ 43,567	$ 43,567	$ 43,567	$ 43,567	$ 43,567	Harvest 8.28.23 email	Difference in retrofit and conventional O&M; adjusted to 2020$
Other Indirect Annual Costs ($/yr)	OAC	$ 38,280	$ 36,801	$ 36,801	$ 36,801	$ 36,801	$ 36,801	$ 38,156	$ 36,974	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 175,720	$ 170,616	$ 170,616	$ 170,616	$ 170,616	$ 170,616	$ 175,293	$ 171,212	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	71%	70%	63%	63%	60%	30%	63%	63%	Units 1-6: Current actual based on recent test data; Units 19/20: Current actual based on 67.6 ppm as indicated by 2019 submittal	(Current actual emissions rate - Target emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	58.0	47.5	32.5	46.1	41.2	48.4	37.6	30.3	CY 2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	0%	0%	0%	0%	-	Not requested by Harvest
Projected Actual Emissions (ton/yr)	PAE	58.0	47.5	32.5	46.1	41.2	48.4	37.6	30.3	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	41.3	33.4	20.5	29.0	24.9	14.7	23.7	19.1	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 4,258**	**$ 5,104**	**$ 8,325**	**$ 5,876**	**$ 6,858**	**$ 11,638**	**$ 7,399**	**$ 8,954**	-	TAC/ER
Price Index	PI	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 5,705**	**$ 6,839**	**$ 11,155**	**$ 7,874**	**$ 9,189**	**$ 15,595**	**$ 9,915**	**$ 11,999**	-	CE1 x PI

NMED Final Cost Evaluation
Harvest Four Corners - Kutz Canyon Processing Plant

Facility Information

Harvest - Kutz Canyon PP	**Facility**
Six 1975 NG CT and two 1981 NG CT	**Units**
1, 2, 3, 4, 5, 6, 19, 20	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
25	**Target Emissions Rate (ppmvd @ 15% O2)***

*Consistent with manufacturer specifications for similar, new CT equipped with DLN.

Additional Information

2020	**Calendar year associated with cost estimates**
3830	**Nameplate Power Output (hp/unit; Units 1, 2 and 3)**
3016	**Nameplate Power Output (hp/unit; Units 19 and 20)**

Economic Evaluation

Cost Component		Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6	Unit 19	Unit 20	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 9,260,940	$ 9,260,940	$ 9,260,940	$ 9,260,940	$ 9,260,940	$ 9,260,940	$ 7,292,688	$ 7,292,688	9/8/20 info from El Paso Natural Gas (2020$)	All-in estimate ($/HP) x Maximum Capacity (HP); Using EPNG's $2418/hp cost metric because Harvest did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered CT.
Interest Rate (%)	R	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	Harvest - Pricing Term Sheet (v8.28.23)	
Useful Life (yr)	Y	30	30	30	30	30	30	30	30	ERG experience based on discussions with CT manufacturers	
Capital Recovery Factor	CRF	0.0847	0.0847	0.0847	0.0847	0.0847	0.0847	0.0847	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 784,135	$ 784,135	$ 784,135	$ 784,135	$ 784,135	$ 784,135	$ 617,481	$ 617,481	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 43,567	$ 43,567	$ 43,567	$ 43,567	$ 43,567	$ 43,567	$ 43,567	$ 43,567	Harvest 8.28.23 email	Difference in retrofit and conventional O&M; adjusted to 2020$
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 827,702	$ 827,702	$ 827,702	$ 827,702	$ 827,702	$ 827,702	$ 661,048	$ 661,048	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	71%	70%	63%	63%	60%	30%	63%	63%	Units 1-6: Current actual based on recent test data; Units 19/20: Current actual based on 67.6 ppm as indicated by 2019 submittal	(Current actual emissions rate - Target emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	58.0	47.5	32.5	46.1	41.2	48.4	37.6	30.3	CY 2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	0%	0%	0%	0%	-	Not requested by Harvest
Projected Actual Emissions (ton/yr)	PAE	58.0	47.5	32.5	46.1	41.2	48.4	37.6	30.3	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	41.3	33.4	20.5	29.0	24.9	14.7	23.7	19.1	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 20,055**	**$ 24,761**	**$ 40,387**	**$ 28,507**	**$ 33,268**	**$ 56,461**	**$ 27,904**	**$ 34,573**	-	TAC/ER
Price Index	PI	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 26,873**	**$ 33,180**	**$ 54,118**	**$ 38,199**	**$ 44,580**	**$ 75,657**	**$ 37,391**	**$ 46,328**	-	CE1 x PI

NMED Final Cost Evaluation
Harvest Four Corners - Kutz Canyon Processing Plant

Facility Information

Harvest - Kutz Canyon PP	**Facility**
Six 1975 NG CT and two 1981 NG CT	**Units**
1, 2, 3, 4, 5, 6, 19, 20	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Target Emissions Rate (lb/hr)**

Additional Information

2020	**Calendar year associated with cost estimates**

Economic Evaluation

Cost Component		Value	Source	Methodology/Note
		All Units (Combined)		
Purchased equipment costs ($)	PEC	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 42,713,001	Harvest 10.23.20 estimate	
Interest Rate (%)	R	7.50%	Harvest - Pricing Term Sheet (v8.28.23)	
Useful Life (yr)	Y	25	Consistent with other FFAs	
Capital Recovery Factor	CRF	0.090	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 3,831,812	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 716,000	-	AED + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 1,200,000	Harvest 10.23.20 estimate	
Associated non-electricity O&M ($/yr)	AOM	$ 116,000	Harvest 10.23.20 estimate	
Annual Fuel Credit ($/yr)	AFC	$ (600,000)	ERG Calculation	Assumes fuel savings is 50% of AED
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 4,547,812	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	341.6	CY 2023 emissions testing and average operating hours (2016-2021)	BAE of all units
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by Harvest
Projected Actual Emissions (ton/yr)	PAE	341.6	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	341.6	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 13,314**	-	TAC/ER; Cost info provided by Harvest on 10.23.20 and thus assumed in 2020$
Price Index	PI	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 17,840**	-	CE1 x PI

NMED Final Cost Evaluation
Harvest Four Corners - Kutz Canyon Processing Plant

Unit 1: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	34.81	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	234,317,556	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5800	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.480	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0959	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours	
Estimated SCR equipment life	20	Years*	

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F	*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour	

Concentration of reagent as stored (C_{stored})	29	percent*	
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*	
Number of days reagent is stored ($t_{storage}$)	14	days	

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 1: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	35	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	295,766,828	scf/Year	
Actual Annual fuel consumption (Mactual) =		234,317,556	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.792	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6940	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	13.36	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	46.36	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.24		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.9	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	144.14	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	5	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	18	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	900	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	20.61	kW

Unit 1: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,571,614	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$39,732 in 2024 dollars
Indirect Annual Costs (IDAC) =	$255,058 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$294,790 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,858 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$8,780 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$14,302 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$3,792 in 2024 dollars
Direct Annual Cost =		$39,732 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,782 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$252,275 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$255,058 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$294,790 per year in 2024 dollars
NOx Removed =	46 tons/year
Cost Effectiveness =	$6,359 per ton of NOx removed in 2024 dollars

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Unit 2: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	34.81	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	181,477,934	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5800	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.508	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1016	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 2: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	35	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	295,766,828	scf/Year	
Actual Annual fuel consumption (Mactual) =		181,477,934	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.614	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5375	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	14.15	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	38.03	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.24		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.9	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	145.45	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	6	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	19	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	900	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	20.61	kW

Unit 2: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,571,614	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$34,965 in 2024 dollars
Indirect Annual Costs (IDAC) =	$255,058 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$290,022 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,858 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$7,204 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$11,077 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$3,826 in 2024 dollars
Direct Annual Cost =		$34,965 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,782 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$252,275 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$255,058 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$290,022 per year in 2024 dollars
NOx Removed =	38 tons/year
Cost Effectiveness =	$7,625 per ton of NOx removed in 2024 dollars

NMED Final Cost Evaluation
Harvest Four Corners - Kutz Canyon Processing Plant

Unit 3: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	34.81	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	174,725,267	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5800	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.361	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0722	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 3: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	35	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	295,766,828	scf/Year
Actual Annual fuel consumption (Mactual) =		174,725,267	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.591	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5175	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	10.05	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	26.00	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.24	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.9	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	138.68	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	4	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	13	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	700	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	20.61	kW

Unit 3: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,571,614	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$32,095 in 2024 dollars
Indirect Annual Costs (IDAC) =	$255,058 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$287,153 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,858 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$4,924 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$10,665 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$3,648 in 2024 dollars
Direct Annual Cost =		$32,095 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,782 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$252,275 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$255,058 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$287,153 per year in 2024 dollars
NOx Removed =	26 tons/year
Cost Effectiveness =	$11,045 per ton of NOx removed in 2024 dollars

Unit 4: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	34.81	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	220,373,298	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5800	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.406	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0811	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024			
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI
Annual Interest Rate (i)	7.5	Percent		
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia		
Electricity ($Cost_{elect}$)	0.1000	$/kWh		
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	60.00	$/hour (including benefits)*		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 4: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	35	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	295,766,828	scf/Year	
Actual Annual fuel consumption (Mactual) =		220,373,298	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.745	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6527	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	11.30	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	36.86	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.24		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.9	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	140.74	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	4	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	15	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	700	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	20.61	kW

Unit 4: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,571,614	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$36,993 in 2024 dollars
Indirect Annual Costs (IDAC) =	$255,058 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$292,051 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,858 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$6,982 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$13,451 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$3,702 in 2024 dollars
Direct Annual Cost =		$36,993 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,782 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$252,275 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$255,058 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$292,051 per year in 2024 dollars
NOx Removed =	37 tons/year
Cost Effectiveness =	$7,922 per ton of NOx removed in 2024 dollars

Unit 5: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	34.81	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	233,777,342	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5800	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.342	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0684	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 5: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	35	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	295,766,828	scf/Year	
Actual Annual fuel consumption (Mactual) =		233,777,342	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.790	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6924	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	9.52	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	32.96	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.24		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.9	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	137.81	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	4	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	13	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	600	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	20.61	kW

Unit 5: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,571,614	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$36,995 in 2024 dollars
Indirect Annual Costs (IDAC) =	$255,058 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$292,052 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,858 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$6,242 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$14,269 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$3,625 in 2024 dollars
Direct Annual Cost =		$36,995 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,782 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$252,275 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$255,058 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$292,052 per year in 2024 dollars
NOx Removed =	33 tons/year
Cost Effectiveness =	$8,861 per ton of NOx removed in 2024 dollars

Unit 6: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	34.81	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	277,669,680	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5800	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.338	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0676	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 6: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	35	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	295,766,828	scf/Year	
Actual Annual fuel consumption (Mactual) =		277,669,680	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.939	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8224	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	9.41	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	38.69	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.24		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.9	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	137.62	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	4	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	13	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	600	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	20.61	kW

Unit 6: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,571,614	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$40,754 in 2024 dollars
Indirect Annual Costs (IDAC) =	$255,058 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$295,811 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,858 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$7,327 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$16,948 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$3,620 in 2024 dollars
Direct Annual Cost =		$40,754 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,782 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$252,275 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$255,058 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$295,811 per year in 2024 dollars
NOx Removed =	39 tons/year
Cost Effectiveness =	$7,647 per ton of NOx removed in 2024 dollars

NMED Final Cost Evaluation
Harvest Four Corners - Kutz Canyon Processing Plant

Unit 19: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	27.41	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	127,931,057	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5800	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.570	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1140	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 19: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	27	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	232,891,950	scf/Year
Actual Annual fuel consumption (Mactual) =		127,931,057	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.549	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4812	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	12.50	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	30.07	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.24	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.9	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	116.76	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	5	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	17	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	800	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	16.23	kW

Unit 19: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,201,603	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$27,583 in 2024 dollars
Indirect Annual Costs (IDAC) =	$218,737 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$246,320 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$11,008 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$5,694 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$7,808 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$3,072 in 2024 dollars
Direct Annual Cost =		$27,583 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,760 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$215,977 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$218,737 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$246,320 per year in 2024 dollars
NOx Removed =	30 tons/year
Cost Effectiveness =	$8,193 per ton of NOx removed in 2024 dollars

Unit 20: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	27.41	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	103,259,399	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5800	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.570	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1140	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 20: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	27	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	232,891,950	scf/Year
Actual Annual fuel consumption (Mactual) =		103,259,399	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.443	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3884	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	12.50	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	24.27	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.24	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.9	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	116.76	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	5	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	17	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	800	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	16.23	kW

Unit 20: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,201,603	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$24,978 in 2024 dollars
Indirect Annual Costs (IDAC) =	$218,737 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$243,716 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$11,008 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$4,596 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$6,303 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$3,072 in 2024 dollars
Direct Annual Cost =		$24,978 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,760 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$215,977 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$218,737 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$243,716 per year in 2024 dollars
NOx Removed =	24 tons/year
Cost Effectiveness =	$10,043 per ton of NOx removed in 2024 dollars

REGIONAL HAZE FOUR-FACTOR ANALYSIS

Harvest Four Corners, LLC
Kutz Canyon Processing Plant

Prepared By:

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1. EXECUTIVE SUMMARY

In the 1977 amendments to the Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across the United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

> *(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A).*
>
> This is known as a four-factor analysis.
>
> *(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B).*
>
> The uniform rate of progress or improvement is sometimes referred to as the glidepath and is part of the state's Long-Term Strategy (LTS).

The second implementation planning period (2018-2028) for national regional haze efforts is currently underway. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural or biogenic and manmade or anthropogenic sources of emissions. Using a Photochemical Grid Model (PGM), the Western Region Air Partnership (WRAP), in coordination with the EPA, is tasked with comparing anthropogenic source contributions against natural background concentrations.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for major sources and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I area. From this analysis, 24 facilities were identified by the NMED. On July 18, 2019 the NMED informed Harvest Four Corners, LLC (Harvest) that its Kutz Canyon Processing Plant (Kutz) facility was identified as one of the sources potentially contributing to regional haze at the Mesa Verde National Park Class I area.

In coordination with WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. In the NMED's July 18, 2019 notification letter to Harvest, it specifies that any equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The subject equipment at Kutz, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant are reported in Table 1.

Table 1. Summary of Equipment and Applicability to a Four-Factor Analysis

Equipment	NO_X Hourly PTE (lb/hr)	NO_X Annual PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
Natural Gas-Fired Simple Cycle Turbine (Unit 1)	15.5	67.9	Yes	0.029	0.13	No
Natural Gas-Fired Simple Cycle Turbine (Unit 2)	15.5	67.9	Yes	0.029	0.13	No
Natural Gas-Fired Simple Cycle Turbine (Unit 3)	15.5	67.9	Yes	0.029	0.13	No
Natural Gas-Fired Simple Cycle Turbine (Unit 4)	15.5	67.9	Yes	0.029	0.13	No
Natural Gas-Fired Simple Cycle Turbine (Unit 5)	15.5	67.9	Yes	0.029	0.13	No
Natural Gas-Fired Simple Cycle Turbine (Unit 6)	15.5	67.9	Yes	0.029	0.13	No
Natural Gas-Fired Simple Cycle Turbine (Unit 19)	15.5	67.9	Yes	0.029	0.13	No
Natural Gas-Fired Simple Cycle Turbine (Unit 20)	15.5	67.9	Yes	0.029	0.13	No
Clark HRA-8 Reciprocating Compressor Engine (Unit 16)	37.1	162.0	Yes	0.007	0.031	No
Clark HRA-8 Reciprocating Compressor Engine (Unit 17)	37.1	162.0	Yes	0.007	0.031	No
Clark HRA-8 Reciprocating Compressor Engine (Unit 18)	37.1	162.0	Yes	0.007	0.031	No

Once the applicability of equipment and pollutants has been determined, potential retrofit control technologies must be identified. In accordance with 40 CFR 51 Appendix Y and at the recommendation of the NMED[1], this is primarily achieved by utilizing the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) data. In order to determine the most relevant and current retrofit controls available, the RBLC is queried for the previous ten years. Summaries of the result of this search are provided and discussed under Section 2 of this report. Harvest engineers then reviewed the list of available retrofit technologies and performed a technical feasibility assessment for each control option. The four-factor analysis is then conducted for those controls that are technically feasible.

[1] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

NO_X is the only pollutant subject to evaluation in this four-factor analysis for the eight (8) turbines and three (3) engines located at Kutz. The turbines, Unit 1 through Unit 6, are Solar model Centaur 40-T4002 natural gas-fired, simple cycle turbines. Turbine Unit 19 and Unit 20 are Solar model Centaur 40-T4001 natural gas-fired, simple cycle turbines. The engines, Units 16, 17, and 18, are Clark model HRA-8 natural gas-fired, two-stroke lean-burn (2SLB) reciprocating compressor engines.

Units 1 through 6 are rated at 3,830 horsepower and were manufactured in 1975. Units 19 and 20 are rated at 3,016 horsepower and were manufactured in 1981. The engines are each rated at 830 horsepower and were manufactured prior to 1973. The units are de-rated in the 2016 Emission Inventory submittal to account for the altitude of the facility. Units 1 through 6 are rated at 3,692 hp, Units 19 and 20 at 2,907 hp, and Units 16 through 18 at 723 hp.

2.1. COMBUSTION TURBINES

2.1.1. Combustion Turbine Background

A gas turbine is an internal combustion engine that operates with a rotary, rather than reciprocating, motion and is composed of three primary components: a compressor, a combustor, and a power turbine. The compressor draws in ambient air and compresses it up to 30 times the ambient pressure, then directs it into the combustor where fuel is introduced, ignited, and burned. Exhaust gas from the combustor is then diluted with additional air and sent to the power turbine at temperatures up to 2600 °F. The hot exhaust gas expands in the power turbine section, generating energy in the form of shaft horsepower.[2]

The treatment of the exhaust gases exiting the turbine dictate the cycle designation of these units. The heat content can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).[3] The units at Kutz are simple cycle turbines.

NO_X is formed via three fundamentally different mechanisms. The principle NO_X formation mechanism, thermal NO_X, arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion. Most thermal NO_X forms in the highest temperature regions of the combustion chamber. The second NO_X formation mechanism, fuel NO_X, arises from the evolution and reaction of fuel bound nitrogen compounds with oxygen. The final NO_X formation mechanism, prompt NO_X, arises from early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The significance of prompt NO_X is negligible in comparison to thermal and fuel NO_X. Fuel NO_X will also be negligible for Kutz's turbines assessed here, as these combustion turbines fire natural gas, which contains a negligible amount of nitrogen compounds. Therefore, this analysis will focus on thermal NO_X.

[2] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"
[3] Ibid.

The PTE from each turbine is reported in the facility's New Source Review (0301M11) and Title V (P097R3) permits, as well as summarized in Table 1 of this report.

2.1.2. Potential NO_X Controls for Combustion Turbines

There are three general methods of controlling NO_X emission from gas turbines: (1) wet controls, which use steam or water injection to reduce combustion temperatures and NO_X formation; (2) dry controls that use advanced combustor design to suppress NO_X formation; and (3) post-combustion, catalytic controls to selectively reduce NO_X.[4]

The retrofit control equipment that was identified for combustion turbines during a comprehensive review of the RBLC, available literature, and manufacturer's input is reported in Table 2. A more detailed table summarizing the RBLC review is provided in Appendix A. A detailed discussion, including a description, the technical feasibility, and the anticipated performance of each control is provided below.

Table 2. Potential Control Options for Combustion Turbines

Control Equipment	Technically Feasible?	NO_X Control Efficiency
Good Combustion Practices	Yes	Base Case
Improved Combustion Technology	Yes	63%
Water/Steam Injection	No	N/A
Selective Catalytic Reduction	No	N/A

2.1.2.1. Good Combustion Practices

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from combustion turbines; therefore, it has been determined that this method of NO_X control is feasible for the units at Kutz. However, these practices have been developed for and are currently in use at Kutz, as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices is included in this report.

2.1.2.2. Improved Combustion Technology

The improved combustion technology control option, commonly referred to as Dry Low NO_X (DLN) control, seeks to reduce the combustion temperature and residence time of fuel in the combustor (thereby decreasing NO_X formation) by increasing the air-to-fuel ratio in the combustion chamber. There are several levels of

[4] Ibid.

improvements that can be made to the combustion chamber, which achieve this NO_X control at varying levels. The improved combustion technology available for the units at Kutz is produced by the manufacturer of the units, Solar, and is called SoLoNO$_X$. SoLoNO$_X$ utilizes lean-premixed combustion technology to ensure an extremely uniform air/fuel mixture and stringently controls the combustion process to prevent undesirable emissions from forming.

Based on communication with Solar, SoLoNO$_X$ is available for both the T4001 (Units 19 and 20) and T4002 (Units 1 through 6) Solar turbines located onsite. However, in order to support the technology each of the units would need to be uprated to model T4701 and T4702, respectively, because installation of SoLoNO$_X$ requires the turbine combustors to be capable of handling significantly higher temperatures. Uprating the units involves completely replacing the combustor section of the turbine with a much larger and more robust combustor.

Improved combustion technology, such as SoLoNO$_X$, was identified in this review of RBLC as a potential control of NO_X emissions from natural gas-fired combustion turbines, and AP-42 Section 3.1 also lists this as an available control technique for gas turbines.[5] Therefore, it has been determined that this control technology is technically feasible for the turbines located at Kutz. Solar can guarantee an output NO_X concentration of 25 parts per million (ppm) for uprated units with SoLoNO$_X$ installed. This is a resulting NO_X emissions reduction of approximately 63%, based on the currently permitted hourly emission rate and turbine stack parameters.

2.1.2.3. Water/Steam Injection

Water injection is a control technology for gas turbines that has been demonstrated to effectively suppress NO_X emissions. Injection of water has the effect of increasing the thermal mass by dilution and thereby reducing the peak temperature in the flame zone. Additionally, the latent heat of vaporization from the flame zone is absorbed when water injection is utilized, further reducing the combustion temperature. Water is typically injected at a water-to-fuel weight ratio of less than one.[6] Steam injection is not discussed as an option because Solar does not manufacture turbines with steam injection technology.

The capability of these units to be retrofit for water injection is dependent on the number of shafts employed in the unit, per communications with Solar. The shaft is the piece of equipment in the unit that connects the turbine to the generator and turns to generate the power output. Solar has indicated that turbine units with one shaft are mechanically capable of installing water injection, while two-shaft units are not. The Solar T4002 turbines (Units 1 through 6) located at Kutz are two-shaft units and the Solar T4001 turbines (Units 19 & 20) are one-shaft units. Therefore, the model T4002 turbines are not mechanically capable of being retrofit for water injection, while the model T4001 turbines are.

Despite the Solar T4001 units being mechanically capable of supporting water injection, Solar has stated that they do not offer water injection retrofits for any of the Centaur 40 conventional combustion line of turbines. This is primarily due to the design of the combustor housing of the conventional Centaur 40. The injectors on this style of combustor intersect directly into the combustor without using direct air flow for the direction of fuel. The style of injector needed to implement water injection technology is referred to by Solar as a Dual Lined Injector. This type of injector introduces fuel laterally into the front of a combustor and utilizes a controlled flow to disperse fuel.

Solar considers the control technique to be antiquated technology in comparison to the other control methods they have available, such as SoLoNO$_X$. Solar has retired this control option and does not recommend water

[5] Ibid.
[6] Ibid.

injection be installed to control emissions from their turbine units. They have stated that if there were direct modifications made to the turbine engine or it's supporting hardware, it could affect the unit's warranty with Solar.

Furthermore, approximately 5 gallons per minute (gpm) of de-ionized or de-mineralized water is needed to properly implement this control, per conversations with Solar. For a continuously operating turbine, this represents a total water usage of approximately 2.6 million gallons per year, per unit, without taking into account leaks and evaporative losses that would occur during transport. Kutz is located in San Juan County, in the northwestern part of the state. The National Drought Mitigation Center currently classifies this region as experiencing severe drought conditions.[7] The New Mexico Office of the State Engineer projects that the water demand in the San Juan region will exceed the drought-adjusted available water supply before 2030.[8] The implementation of this control may pose an unsustainable burden on this region's watershed.

Based on the communication with the turbine manufacturer detailed above, as well as the lack of available water in the region, it has been determined that water and steam injection are technically infeasible for the Solar turbines located at Kutz.

2.1.2.4. Selective Catalytic Reduction Systems

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[9] The chemical reactions for this process are shown in the equations below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

An SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and an electronic control system. The electronic controls regulate the quantity of reagent injected as a function of turbine load, speed, and temperature, so NO_X emissions reductions can be achieved. The lifespan of the catalyst is primarily determined by poisoning of active sites by flue gas constituent, thermal sintering, or compacting, of active sited due to high temperatures in the reactor, fouling caused by ammonia-sulfur salts and particulate matter in the gas, and erosion due to high gas velocities.[10]

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as ammonia slip. Unreacted ammonia in the exhaust can form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams can blind the catalyst and may necessitate the application of a soot blower.[11]

For an SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 and 850 °F), dependent on the material of the catalyst. Exhaust gas temperatures greater than the

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[7] Brian Fuchs, National Drought Mitigation Center, "United States Drought Monitor – New Mexico", https://droughtmonitor.unl.edu/CurrentMap/StateDroughtMonitor.aspx?NM

[8] State of New Mexico Interstate Stream Commission, Office of the State Engineer, "San Juan Basin Regional Water Plan 2016", Figure ES-3. Available Supply and Projected Demand.

[9] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

[10] Ibid.

[11] Ibid.

upper limit will cause the NO_X and ammonia to pass through the catalyst unreacted.[12] The exhaust temperature of the turbines assessed here is approximately 1,271 °F. It is unlikely that SCR control would function effectively on the Solar turbines due to the high exhaust temperature of these units. In addition, there are site-specific space limitations associated with the building and stack orientations that will prevent installation of the necessary equipment for this control method (i.e., SCR module and reagent storage systems).

Furthermore, Harvest does not anticipate that the current electricity availability at Kutz will be sufficient to support the substantial energy burden associated with SCR control. Installation of this control will require the facility to expand its current power generation.

Communication with Solar has indicated that SCR controls are available for each of the turbine models assessed here. However, it is not anticipated that the exhaust temperature, space, and energy limitations can be overcome; therefore, it has been determined that SCR is not a technically feasible control option for the turbines located at Kutz.

2.2. TWO-STROKE LEAN-BURN ENGINES

2.2.1. Two-Stroke Lean-Burn Engines Background

A reciprocating internal combustion engine (RICE) is a device that uses the combustion of fuel and air in an internal chamber to generate a reciprocating motion and convert heat energy into mechanical work. The units use a piston to draw air and fuel into the combustion chamber and compress it. The compressed air/fuel mixture is then ignited, generating combustion in the chamber. The energy of combustion pushes out the piston, turning a crankshaft and producing mechanical work. In the same cycle, the products of combustion remaining in the chamber are released and exhausted from the unit.

Natural gas-fired RICE are separated into multiple design classes, including 2-stroke lean-burn (2SLB), 4-stroke lean-burn (4SLB), and 4-stroke rich-burn (4SRB). The four-stroke design uses four strokes of the piston, or two turns of the crankshaft, to complete the power cycle. The two-stroke design completes the power cycle in a single revolution of the crankshaft. Rich-burn engines are designed to operate close to the stoichiometric, or chemically balanced, air-to-fuel ratio (around 16:1) with exhaust oxygen levels less than 4%, while lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1), with exhaust oxygen levels of 12% or more.[13]

NO_X is formed in reciprocating engines via the same three mechanisms applicable to the turbines:

(1) Thermal NO_X - the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion,
(2) Fuel NO_X - the evolution and reaction of fuel-bound nitrogen compounds with oxygen, and
(3) Prompt NO_X - the early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The Kutz engines also use natural gas fuel; therefore, the formation of prompt and fuel NO_X will again be insignificant, and this analysis will focus on thermal NO_X. The rate of NO_X formation through the thermal NO_X mechanism is highly dependent upon the air-to-fuel ratio, combustion temperature, and residence time at the combustion temperature. Maximum thermal NO_X formation occurs near the stoichiometric air-to-fuel mixture ratio because combustion temperatures are greatest at this ratio.[14]

[12] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"
[13] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
[14] Ibid.

NO_X reduction in natural gas-fired RICE can be accomplished by three general methods, as follows:[15]

(1) Operational control methods, such as adjusting the timing or other operating parameters.
(2) Combustion control techniques, for example reducing the peak flame temperature or introducing inerts that limit initial NO_X formation.
(3) Post-combustion NO_X control technologies, which employ various strategies to chemically reduce NO_X.

The PTE from each engine is reported in the facility's New Source Review (0301M11) and Title V (P097R3) permits, as well as summarized in Table 1 of this report.

2.2.2. Potential NO_X Controls for 2SLB Engines

Retrofit control options identified for 2SLB RICE were identified via comprehensive review of the RBLC and available technical literature and are summarized in Table 3. A detailed description and discussion of the technical feasibility and anticipated performance of each control is provided below.

Table 3. Potential Control Equipment for 2SLB RICE

Control Equipment	Technically Feasible?	NO_X Control Efficiency
Good Combustion Practices and Fuel Selection	**Yes**	**Base Case**
Clean Burn Technology	**Yes**	**80% - 93%**
Selective Catalytic Reduction	**No**	**N/A**
Non-Selective Catalytic Reduction	**No**	**N/A**

2.2.2.1. Good Combustion Practices and Fuel Selection

By following the same concepts from engineering knowledge, experience, and manufacturer's recommendations referenced above, good combustion practices for operation of engines can be developed and maintained. This is achieved by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from 2SLB engines; therefore, it has been determined that this method of NO_X control is feasible for the engines at Kutz. However, these practices have been developed for and are currently in use at Kutz, as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices is included in this report.

2.2.2.2. Clean Burn Technology

Clean Burn Technology (CBT) is another term for utilizing combustion mixtures in engines with fuel-lean air-to-fuel ratios. This method of reducing NO_X emissions involves reconfiguring the engines by adding or enhancing an air-to-fuel ratio controller, making the unit capable of operating at more desirable ratios.

[15] Ibid.

Rich-burn engines are normally designed to operate close to the stoichiometric, or chemically balanced, air-to-fuel ratio of 16:1, while lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1). A combustion mixture with a higher air-to-fuel ratio results in reduced NO_X emissions, because using fuel-lean mixtures lowers the combustion temperature by diluting energy input. 2SLB engines are typically designed to operate at the high air-to-fuel ratios employed in CBT; however, further increasing the air-to-fuel ratio in lean-burn engines can decrease the NO_X emissions.[16]

In order to avoid derating the engine, combustion air must be increased at constant fuel flow. To achieve this, the engine would need to be retrofitted with a turbocharger, which forces additional air into the combustion chamber, as well as an automatic air-to-fuel ratio controller.

Many 2SLB engines, such as naturally aspirated engines, do not have identical air-to-fuel ratios in each cylinder, which can result in limited ability to vary the air-to-fuel ratio. To maintain acceptable engine performance at lean conditions, high energy ignition systems (HEIS) have been developed that promote flame stability at very lean conditions.[17]

There is limited manufacturer support available to provide input on the potential effect installation of these controls could have on the engines. As such, a third-party control vendor with significantly less unit-specific experience and familiarity would need to be employed to install this control. Harvest is concerned that the addition of this control equipment by a third-party vendor could negatively affect the units and ultimately be operationally detrimental due to their limited historical knowledge of the engines.

Despite the potential drawbacks to installation of CBT control on these units discussed above, 2SLB engines are mechanically capable of being retrofit to support the combustor modifications and more sensitive air-to-fuel ratio controllers necessary to employ CBT. Therefore, it has been determined that this method of NO_X control is feasible for the 2SLB engines at Kutz. On 2SLB RICE, CBT is estimated to achieve an 80 to 93% reduction in NO_X emissions; however, this reduction is specific to each engine and typical loading.[18]

2.2.2.3. Selective Catalytic Reduction

Implementation of SCR controls for engines follows the same process and has the same technical drawbacks as discussed in Section 2.1.2.4 of this report.

For engines that typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia to gain the reductions needed.[19] Kutz does typically operate with variable loads; therefore, the facility expects to have periods of ammonia slip or insufficient ammonia.

In order for the chemical reactions necessary for SCR to occur effectively, the exhaust streams injected with the reagent must be fairly oxygen rich. The exhaust oxygen levels for 2SLB engines are sufficient to support these reactions; therefore, this technology can be used on lean-burn engines.

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[16] State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines, State of New Jersey Department of Environmental Protection, 2003.
[17] Ibid.
[18] U.S. EPA, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document – NO_X Emissions from Stationary Reciprocating Internal Combustion Engines", EPA-453/R-93-032, Section 5.2.5.4, July 1993
[19] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"

AP-42 Section 3.2 does list SCR as an available control technology for 2SLB engines; however, the RBLC does not identify SCR as a control for these specific engine models.[20] This is likely because there is limited operating experience to date with the use of SCR on 2SLB RICE. Additionally, there is historical precedent that installation of SCR on 2SLB engines can result in significant technical complications, including a necessity to derate the engines and unreliable operation post-retrofit. The engines at Kutz are currently de-rated to account for the altitude of the facility. It is not operationally appropriate to de-rate the units further, as would be necessary if SCR control is implemented.

An engine control vendor contacted indicated that the Clark HRA-8 model of engines are poorly suited for installation of SCR controls and they do not typically recommend this for control due to the availability of more suitable options, such as CBT. The control vendor stated that significant challenges would need to be overcome to install this equipment on the units. Primarily, the poor air-to-fuel ratio employed in these units will make it difficult to regulate the SCR and greatly affect the NO_X reduction capability out of the engine. Additionally, a turbocharger and intercooler would need to be installed in the units to support the SCR equipment. As SCR control technology is not listed in the RBLC tables for 2SLB engines, has not been a proven as an effective method of controlling NO_X, and has significant operating challenges, Harvest has determined this control is technically infeasible for the Clark HRA-8 engines at Kutz.

2.2.2.4. Non-Selective Catalytic Reduction

Non-Selective Catalytic Reduction (NSCR) is a control technique that uses residual hydrocarbons and carbon monoxide (CO) in engine exhaust as a reducing agent for NO_X. In an NSCR system, hydrocarbons and CO are oxidized by oxygen (O_2) and NO_X. The excess hydrocarbons, CO, and NO_X pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H_2O and CO_2, while reducing NO_X to N_2.[21] This technique does not require additional reagents to be injected because the unburnt hydrocarbons in the engine exhaust are used as the reductant. The chemical reactions for this process are shown in the equations below.[22]

Phase 1:
$$\left.\begin{array}{l} 2CO + O_2 \rightarrow 2CO_2 \\ 2H_2 + O_2 \rightarrow 2H_2O \\ HC + O_2 \rightarrow CO_2 + H_2O \end{array}\right\}$$

Phase 2:
$$\left.\begin{array}{l} NO_X + CO \rightarrow CO_2 + N_2 \\ NO_X + H_2 \rightarrow H_2O + N_2 \\ NO_X + HC \rightarrow CO_2 + H_2O + N_2 \end{array}\right\}$$

The reactions in Phase 1 of the chemical process above function to remove excess oxygen from the exhaust stream. This step is necessary because if the oxygen is not removed, it will react more readily with the CO and hydrocarbons than the NO_X, thus reducing the potential for NO_X removal.

Despite this oxygen removal step in the chemical process, the engine exhaust gas stream must already have low levels of excess oxygen, or the oxygen will not be fully removed in Phase 1 and the NO_X removal will not be efficient. Consequently, application of the NSCR control technique is effectively limited to engines with normal exhaust

[20] Ibid.
[21] Ibid.
[22] U.S. EPA, "Compliance Assurance Monitoring Technical Guidance Document", Appendix B Review Draft, 2005

oxygen levels of 4% or less. This does not include lean-burn engines, which typically have an exhaust excess oxygen level around 8%, ranging from 4% to 17%.[23]

The exhaust oxygen levels for 2SLB engines are not sufficiently low to support the reactions described above; therefore, this technology is not a method used to control NO_X emissions from lean-burn engines. Furthermore, NSCR was not identified in the review of the RBLC as a potential control of NO_X emissions from large natural gas-fired lean-burn stationary RICE and AP-42 Section 3.2 does not list NSCR as an available control technique for 2SLB engines.[24] For these reasons, it has been determined that this method of NO_X control is infeasible for the 2SLB engines at Kutz.

[23] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
[24] Ibid.

Harvest has evaluated the costs of implementing the technologically feasible control technologies as thoroughly as possible in the time provided to complete this assessment. These cost estimates are calculated according to the methods and recommendations in the EPA Air Pollution Control Cost Manual.[25] Cost effectiveness considerations for each unit and control technology are discussed below.

These cost estimates have been developed based on the actual emissions from each unit assessed here, using the 2016 Emission Inventory submittal for Kutz. The full cost estimation for each unit, including the EPA Air Pollution Control Cost Spreadsheet, are included in Appendix B of this report.

3.1. COMBUSTION TURBINES

Cost effectiveness for each combustion turbine control option are summarized Table 4.

Table 4. Cost Analysis Summary of Technically Feasible Control Options for Combustion Turbines at Kutz

Control Equipment	Unit	Capital Cost ($)	Total Annual Cost ($)*	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Improved Combustion Technology	1	467,300	61,603	27.4	2,246
	2	467,300	61,603	25.5	2,412
	3	467,300	61,603	31.1	1,983
	4	667,300	78,339	3.4	23,111
	5	667,300	78,339	36.5	2,145
	6	667,300	78,339	41.0	1,910
	19	467,300	61,603	12.9	4,779
	20	467,300	61,603	30.1	2,043

*Total Annual Cost includes the annualized capital cost, as well as the direct and indirect annual operating costs.

3.1.1. Improved Combustion Technology

Harvest has received an estimated direct capital cost for the equipment and vendor labor associated with implementing SoLoNO$_X$ on the turbines located at Kutz from Solar. Solar has also provided an estimated annual cost necessary to operate and maintain the units post-retrofit.

This cost estimate assumes that SoLoNO$_X$ will reduce NO$_X$ emissions to an outlet concentration of 25 ppm, based on manufacturer's estimations.

[25] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

3.2. 2SLB ENGINES

Cost effectiveness for each engine control option are summarized Table 5.

Table 5. Cost Analysis Summary of Technically Feasible Control Options for Engines at Kutz

Control Equipment	Unit	Capital Cost ($)	Total Annual Cost ($)*	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Clean Burn Technology	16	1,000,000	123,679	121.1	1,021
	17	1,000,000	123,679	71.7	1,725
	18	1,000,000	123,679	70.0	1,767

*Total Annual Cost includes the annualized capital cost, as well as the direct and indirect annual operating costs.

3.2.1. Clean Burn Technology

Harvest has estimated the capital cost for the equipment and labor associated with implementing CBT on the 2SLB engines located at Kutz, as well as the annual costs necessary to operate and maintain the units.

This cost estimate assumes that the CBT control will reduce NO_X emissions by 80%, per the EPA's Alternative Control Techniques document on NO_X emissions from stationary RICE.[26]

[26] U.S. EPA, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document – NO_X Emissions from Stationary Reciprocating Internal Combustion Engines", EPA-453/R-93-032, Section 5.2.5.4, July 1993

The second factor in this analysis is the time necessary for compliance. Consideration of this factor involves estimating the time required for a source to implement a potential control measure. This information is provided here in order to advise the NMED of Harvest's projection of a reasonable compliance timeline based on the equipment and site-specific considerations that could affect the time necessary to comply.

4.1. COMBUSTION TURBINES

4.1.1. Improved Combustion Technology

Harvest estimates that approximately 2-3 years will be needed to implement the improved combustion technology control equipment. Factors that have been considered for this anticipated timeline include budgeting, design, uprating the combustors, procuring the equipment, and installing the control.

4.2. 2SLB ENGINES

4.2.1. Clean Burn Technology

Harvest estimates that approximately 2-3 years will be needed to budget, design, procure, and construct the clean burn technology control equipment. For this anticipated timeline, Harvest has considered the time necessary to identify a control vendor, budget and plan the project, and order and install the equipment.

This section addresses the potential energy and non-air environmental impacts that installation of the technically feasible control options poses on a source. The consideration of energy impacts involves assessing the impact of a control measure on the energy that is consumed by the source. Non-air environmental impacts are assessed based on the effect of the control on non-air environmental media. Some examples of non-air environmental impacts include water resource depletion, solid waste generation, increased noise and odor pollution, and increased land usage.

5.1. COMBUSTION TURBINES

5.1.1. Improved Combustion Technology

It is not anticipated that installation of the improved combustion technology (SoLoNO$_X$) on the turbines at Kutz will have any significant energy or non-air environmental impacts.

5.2. 2SLB ENGINES

5.2.1. Clean Burn Technology

Clean burn technology control employs a combustion mixture with a higher air-to-fuel ratio, because using fuel-lean mixtures lowers the combustion temperature by diluting energy input. This will reduce NO$_X$ emissions; however, a reduction in combustion temperature also tends to increase emissions of CO, due to incomplete combustion.[27]

[27] Solar Turbines, "Developments in Dry Low Emissions Technology", 2006

The anticipated remaining useful life of each source is addressed here for the NMED's consideration. The assessment of this factor involves estimating how long the sources analyzed will remain in operation and the lifetime of potential control measures, accounting for equipment and site-specific limitations.

40 CFR Part 51, Appendix Y includes guidance on the characterization of this factor, stating that the remaining useful life of a source will typically be longer than the useful life of the emission control system. Therefore, it is appropriate to annualize compliance costs based on the useful life of the control equipment, rather than the life of the source.[28]

6.1. COMBUSTION TURBINES

Based on their current age and operating efficiency, it is estimated that the remaining useful life of the turbines will be longer than the control units. The turbines have operated for more than 35 years without any significant deterioration in operating efficiency; therefore, this analysis of the remaining useful life of the equipment will be based on the anticipated useful life of the control device considered.

6.1.1. Improved Combustion Technology

It is anticipated that the estimated useful life of the improved combustion technology, SoLoNO$_X$, will be similar to the useful life of an SCR system. The useful life is estimated to be 20 years, based on default values from the EPA Air Pollution Control Cost Manual.[29]

6.2. 2SLB ENGINES

The 2SLB engines at Kutz have similarly been operating for more than 45 years without any significant deterioration in operating efficiency; therefore, this analysis of the remaining useful life of the equipment will be based on the anticipated useful life of the control device considered.

6.2.1. Clean Burn Technology

The useful life of a clean burn technology control system is conservatively estimated to be 20 years.

[28] 40 CFR 51, Appendix Y, Section II.B.4.f

[29] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

Based on a comprehensive review of the RBLC, available literature, and manufacturer's input of the available control technologies for the natural-gas fired turbines and 2SLB engines located at Kutz, Harvest has determined that SoLoNO$_X$ is the only technically feasible control option for the Solar turbine units. The cost of compliance to install the control on each of these units has been estimated based on manufacturer's input and EPA guidance. The estimated cost effectiveness and NO$_X$ emission reduction for each turbine unit are summarized in Table 6.

Table 6. Summary of Cost Effectiveness and NO$_X$ Reduction for Control of the Turbines at Kutz

Control Equipment	Unit	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Improved Combustion Technology (SoLoNO$_X$)	1	27.4	2,246
	2	25.5	2,412
	3	31.1	1,983
	4	3.4	23,111
	5	36.5	2,145
	6	41.0	1,910
	19	12.9	4,779
	20	30.1	2,043

It is projected that the useful life of these units will be 20 years, based on the life expectancy of the SoLoNO$_X$ control. Harvest estimates that an achievable compliance timeline to implement this control is 2-3 years.

Harvest has further determined that Clean Burn Technology is the only technically feasible control option for the 2SLB engines located at Kutz. The cost of compliance to install this control on each of these units has been estimated by Harvest. The estimated cost effectiveness and NO$_X$ emission reduction for each engine unit are summarized in Table 7.

Table 7. Summary of Cost Effectiveness and NO$_X$ Reduction for Control of the Engines at Kutz

Control Equipment	Unit	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Clean Burn Technology	16	121.1	1,021
	17	71.7	1,725
	18	70.0	1,767

It is projected that the useful life of these units will be 20 years, based on the life expectancy of the CBT control. The only anticipated energy and non-air impact of the CBT control will be an increase in CO emissions. Harvest estimates that 2-3 years would be an achievable compliance timeline to implement this control technology.

At this time, Harvest would like to reiterate their concerns regarding the limited manufacturer support available for these engines. It would be necessary to employ a third-party control vendor with significantly less unit-specific experience and familiarity to install this control. Harvest is concerned that the addition of this control equipment will be operationally detrimental due to this third-party involvement.

Furthermore, Harvest would like to advise the NMED of their judgement that the Kutz facility's potential contribution to regional haze at the Mesa Verde National Park Class I area is such that it does not justify their facility being selected for this assessment. There are hundreds of sources, both major and minor, located closer to the Class I area whose contribution has not been considered. Harvest would argue that only assessing high emitting sources at a limited number of facilities will not effectively address the visibility impairment problem, as required by the State under the RHR.

8. SUPPORTING DOCUMENTATION

Appendix A – RBLC Tables
Appendix B – Cost Analysis Calculations

APPENDIX A - RBLC TABLES

RBLC Analysis for Natural Gas Fired Turbines – NO_X Control

	Control Technology	Good Combustion Technique	Improved Combustion Technology (Low-NO_X Combustors, Ultra-Low NO_X Combustors and other improved combustion technology)[a]	Water/Steam Injection[b]	Selective Catalytic Reduction (SCR)[c]
IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	NO_x emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. Primary combustion occurs at lower temperatures under oxygen-deficient conditions. By following EPA's "Good Combustion Practices" guidance document, good combustion practices can be maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices the unit will operate as intended with the optimal NO_x emissions.	Low-NO_x burners employ multi-staged combustion to inhibit the formation of NO_X. Primary combustion occurs at lower temperatures under oxygen-deficient conditions; secondary combustion occurs in the presence of excess air. This category includes Improved Combustion Technology Lean Head End Liners for the GE turbines assessed here.	Injected water/steam acts as a heat sink, lowering combustion zone peak temperatures, resulting in a decrease in thermal NO_X.	A nitrogen-based reagent (e.g., ammonia, urea) is injected into the exhaust stream downstream of the combustion unit. The reagent reacts selectively with NO_X to produce molecular N_2 and water in a reactor vessel containing a metallic or ceramic catalyst.
	Other Considerations	N/A	N/A	Results in a small efficiency penalty but an increase in power output. May increase CO and VOC emissions. Not available in certain models.	Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as "ammonia slip." Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.
	RBLC Database Information	Included in RBLC for control of NO_X emissions from combustion turbines.	Included in RBLC for the control of NO_X emissions from combustion turbines.	Not included in RBLC for the control of NO_X emissions from combustion turbines; identified as a control option based on AP-42 Section 3.1.	Included in RBLC for the control of NO_X emissions from combustion turbines.
ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	Feasibility Discussion	Technically feasible.	Technically infeasible. This option is not available for the turbine model.	Technically infeasible. This option is not available for the turbine model.	Technically feasible.
RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	Base Case			63%

a. California EPA, Air Resources Board, "Section 311 - Non-Selective Catalytic Reduction and Other NO_X Controls," http://www.arb.ca.gov/cap/manuals/cntrldev/sncr_etc/311nscr.htm
b. U.S. EPA, AP-42 Section 3.1, "Stationary Gas Turbines"
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

Turbine RBLC Results

Completed RBLC Search on 9/19/2019 for a ten year period of 1/1/2019 to 09/19/2019

RBLCID	FACILITY NAME	EPA REGION	PERMIT NUM	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	COST EFFECTIVENESS	INCREMENTAL COST EFFECTIVENESS	Cost Verified	DOLLAR YEAR USED IN COST ESTIMATES
AK-0083	XENAI NITROGEN OPERATIONS	10	AQ0083CPT06	Five (5) Natural Gas Fired Combustion Turbines	16.11	Natural Gas	37.6	MMBTU/H	Five (5) Natural Gas-Fired Solar Combustion Turbines rated at 37.6 MMBtu/hr each. Installed in 1976.	Nitrogen Oxides (NOx)	A	Selective Catalytic Reduction	0			0	0	N	
CA-1215	QUALCOMM INC.	9	2012- APP-002100	Cogeneration gas turbine	16.11	natural gas	4.37	MW	Manufacturer: Solar Turbines- Model: Mercury 50-6400R	Nitrogen Oxides (NOx)	A	SoLoNOx burner (Ultra lean Premix)	0			0	0	N	
LA-0331	CALCASIEU PASS LNG PROJECT	6	PSD-LA-805	Aeroderivative Simple Cycle Combustion Turbine	16.11	Natural Gas	263	MM BTU/h		Nitrogen Oxides (NOx)	B	Selective Catalytic Reduction (SCR), exclusive combustion of fuel gas, and good combustion practices.	0			0	0	N	
MI-0410	THETFORD GENERATING STATION	5	191-12	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	16.11	natural gas	171	MMBTU/H	Two natural gas fired simple cycle combustion turbines each with an electrical generator (nominal 13MW each; 171 MMBtu/hr heat input rating each). Each turbine is limited to 343 MMscf of natural gas per 12-month rolling time period as determined at the end of each calendar month. Both turbines combined are limited to 5.15 MMscf of natural gas each calendar day.	Nitrogen Oxides (NOx)	P	Dry low-NOx combustors	0			0	0	N	
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	5	185-15	FG-TURBINES	16.11	Natural gas	10504	HP	Five (5) simple cycle natural gas-fired combustion turbines (CTs) to drive compressors that will be used to transport natural gas through pipelines. The turbines are identified as EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, and EUTURBINE5 within the flexible group FGTURBINES. There shall be no more than a combined total of 5 events (startup or shutdown) per clock hour. The total number of startup events for all units combined shall not exceed 500 events per 12-month rolling time period. The total number of shutdown events for all units combined shall not exceed 500 events per 12-month rolling time period. The maximum nominal rating of each turbine shall not exceed 10,504 HP (ISO).	Nitrogen Oxides (NOx)	A	Dry ultra-low NOx burners	0			0	0	N	
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	5	185-15A	FGTURNBINES (5 Simple Cycle CTs: EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5)	16.11	Natural gas	10504	HP	Five simple cycle natural gas-fired combustion turbines (CTs) to drive compressors that will be used to transport natural gas through pipelines (EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5 in FGTURBINES). There shall be no more than a combined total of 5 events (startup or shutdown) per clock hour. The total number of startup events for all units combined shall not exceed 500 events per 12-month rolling time period. The total number of shutdown events for all units combined shall not exceed 500 events per 12-month rolling time period. The maximum nominal rating of each turbine shall not exceed 10,504 HP (ISO).	Nitrogen Oxides (NOx)	A	Dry ultra-low NOx burners.	0			0	0	N	
NV-0050	MGM MIRAGE	9	825	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	16.11	NATURAL GAS	4.6	MMBTU/H	THE TWO UNITS ARE IDENTICAL SOLAR MERCURY COMBUSTION GAS TURBINES FOR ELECTRIC POWER GENERATION. EACH UNIT IS RATED AT 4.6 MMBTU/HR, AND IS ALLOWED TO OPERATE 24 HOURS/DAY AND 8,760 HOURS/YEAR.	Nitrogen Oxides (NOx)	P	LEAN PRE-MIX TECHNOLOGY AND LIMITING THE FUEL TO NATURAL GAS ONLY	0.178	LB/MMBTU		0	0	N	
OK-0148	BUFFALO CREEK PROCESSING PLANT	6	2012-1026-C-PSD	Small Combustion Turbines (<25MW)	16.11	Natural Gas	10179	Horsepower	Solar Taurus 70-10802S times 2	Nitrogen Oxides (NOx)	P	Dry-Low NOx Combustion	0			0	0	N	
OK-0153	ROSE VALLEY PLANT	6	2012-1393-C-PSD	TURBINES 9,443 HP SIEMENS SGT-200-2S	16.11	NATURAL GAS	9443	HP	THERE ARE TO BE LIKE-KIND TURBINES.	Nitrogen Oxides (NOx)	P	DRY LOW-NOx COMBUSTION.	0			0	0	N	
*PA-0314	BEECH HOLLOW	3	63-029220	COMBUSTION TURBINE without DUCT BURNERS UNIT	16.11	Natural Gas	2413	$MMBtu/hr$	CEMS for NOx, CO	Nitrogen Oxides (NOx)	A	SCR	0			0	0	N	
TX-0642	SINTON COMPRESSOR STATION	6	PSDTX1304	Compression Turbine	16.11	natural gas	20000	hp	Two (2) 20,000 horsepower Solar Titan 130S turbines in natural gas pipeline compression service	Nitrogen Oxides (NOx)	P	Solar's SoLoNOx dry emission control technology	0			0	0	N	
TX-0685	GUADALUPE GENERATING STATION	6	106011 PSDTX1110	(2) simple cycle turbines	16.11	natural gas	190	MW	Four models are approved: GE7FA.03, GE7FA.04, GE7FA.05, or Siemens SW 5000FS. 383 MW to 454 MW total plant capacity.	Nitrogen Oxides (NOx)	B	DLN burners, limited operation	0			0	0	N	
*WI-0283	AFE, INC. â€"LCM PLANT	5	17-J0W-207	P90 â€" Natural Gas-Fired Emergency Generator	16.11	Natural Gas	9.51	mmBTU/hr	750 kW or 1,114 brake horsepower	Nitrogen Oxides (NOx)	P	Good Combustion Practices and the Use of Turbocharger and Aftercooler	0			0	0	N	
WY-0067	ECHO SPRINGS GAS PLANT	8	MD-7837	TURBINES S35-S36	16.11	NATURAL GAS	12555	HP	TWO (2) 12,555 HP SOLAR MARS 100-15000S TURBINES	Nitrogen Oxides (NOx)	N	SOLONOX	0			0	0	N	
WY-0067	ECHO SPRINGS GAS PLANT	8	MD-7837	TURBINE S34	16.11	NATURAL GAS	9856	HP	SOLAR CENTAUR 40-T4700S	Nitrogen Oxides (NOx)	N	SOLONOX	0			0	0	N	

RBLC Analysis for Natural Gas-Fired Lean-Burn RICE – NO_X Control

	Control Technology	Good Combustion Practices and Fuel Selection	Clean Burn Technology [a]	Selective Catalytic Reduction (SCR) [b,c]	Non-Selective Catalytic Reduction (NSCR) [c]
IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	NO_x emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following EPA's "Good Combustion Practices" guidance document, good combustion practices can be maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices the unit will operate as intended with the optimal NO_x emissions.	Natural gas fueled engines that operate with a fuel-lean air/fuel ratio are capable of low NO_X emissions.	A nitrogen-based reagent (e.g., ammonia, urea) is injected into the exhaust stream downstream of the combustion unit. The reagent reacts selectively with NO_x to produce molecular N_2 and water in a reactor vessel containing a metallic or ceramic catalyst.	This technique uses residual hydrocarbons and CO in rich-burn engine exhaust as a reducing agent for NO_x. In an NSCR, hydrocarbons and CO are oxidized by O_2 and NO_x. The excess hydrocarbons, CO, and NO_x pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H_2O and CO_2, while reducing NO_x to N_2.[b]
	Other Considerations	N/A	N/A	Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as "ammonia slip." Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.	N/A
ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Not included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Not included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.
	Feasibility Discussion	Technically feasible.	Technically feasible.	Technically infeasible. Site and unit-specific complications exclude SCR as a control option for the 2SLB engines at this facility.	Technically infeasible. The NSCR technique is limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes 4-stroke rich-burn naturally aspirated engines and some 4-stroke rich-burn turbocharged engines. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures.
RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	Base Case	80 - 93%		

a. U.S. EPA, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document – NOX Emissions from Stationary Reciprocating Internal Combustion Engines", EPA-453/R-93-032, Section 5.2.5.4, July 1993
b. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
c. U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"

Engine RBLC Results

Completed RBLC Search on 9/19/2019 for a ten year period of 1/1/2019 to 09/19/2019

RBLCID	FACILITY NAME	EPA REGION	PERMIT NUM	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	COST EFFECTIVENESS	INCREMENTAL COST EFFECTIVENESS	Cost Verified	DOLLAR YEAR USED IN COST ESTIMATES
CA-1192	AVENAL ENERGY PROJECT	9	SJ 08-03	EMERGENCY IC ENGINE	17.13	NATURAL GAS	550	KW	UNIT IS 860 HP	Nitrogen Oxides (NOx)	A	SCR, OPERATIONAL LIMIT OF 50 HRS/YR	0			0	0	N	
CA-1222	KYOCERA AMERICA INC.	9	2011-APP-001634	ICE: Spark Ignition	17.13	natural gas	2889	bhp	anther one is 2328 bhp	Nitrogen Oxides (NOx)	A	SCR with process control NOx monitor	0			0	0	N	
CA-1240	GOLD COAST PACKING	9	14646	Internal Combustion Engine	17.13	Natural gas	881	bhp		Nitrogen Oxides (NOx)	A	SCR catalyst-Urea injection	0			0	0	N	
*FL-0368	NUCOR STEEL FLORIDA FACILITY	4	1050472-001-AC	Emergency Engines	17.13	Natural gas	0		Two 2,000-kW Emergency Natural Gas-Fired Generators & One Emergency Natural Gas-Fired 500 HP Fire Pump	Nitrogen Oxides (NOx)	P	Good combustion practices	0			0	0	N	
IN-0167	MAGNETATION LLC	5	181-32081-00054	EMERGENCY GENERATOR	17.13	NATURAL GAS	620	HP	EMERGENCY NATURAL GAS GENERATOR, IDENTIFIED AS EU017, EXHAUSTS TO STACK SV016.	Nitrogen Oxides (NOx)	P	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0			0	0	N	
*KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	7	C-13309	Spark ignition RICE emergency AC generators	17.13	Natural gas	450	KW	Two (2) spark ignition emergency AC generators, each rated at 450 kW (approximately 604 BHP), which shall burn only natural gas for fuel for the purpose of providing emergency power.	Nitrogen Oxides (NOx)	N		0			0	0	N	
*KS-0030	STATION	7	C-13309	(EGUs)	17.13	Natural Gas	10	MW	G20CM34), used to generate electricity. The generating capacity of	Nitrogen Oxides (NOx)	N		0			0	0	N	
KS-0035	LACEY RANDALL GENERATION FACILITY, LLC	7	C-10593	spark ignition four stroke lean burn reciprocating internal combustion engine (RICE) electric generating units (EGUs)	17.13	Natural gas	12526	BHP	Ten new spark ignition RICE EGUs (Wartsila model 20V34SG), used to generate electricity. The generating capacity of each EGU will be 9.34 megawatts (approximately 12,526 BHP). Each EGU shall be equipped with a selective catalytic reduction (SCR) system and an oxidation catalyst, and shall burn only pipeline quality natural gas for fuel.	Nitrogen Oxides (NOx)	A	Selective Catalytic Reduction (SCR) system and oxidation catalyst	0			0	0	N	
LA-0257	SABINE PASS LNG TERMINAL	6	PSD-LA-703(M3)	Generator Engines (2)	17.13	Natural Gas	2012	hp		Nitrogen Oxides (NOx)	P	Comply with 40 CFR 60 Subpart JJJJ	2	G/BHP-HP-H		0	0	N	
LA-0287	ALEXANDRIA COMPRESSOR STATION	6	PSD-LA-787	Emergency Generator Reciprocating Engine (G30, EQT 15)	17.13	Natural Gas	1175	HP	Non-emergency operation limited to 100 hours per year. Engine is subject to NSPS Subpart JJJJ.	Nitrogen Oxides (NOx)	P	Good combustion practices; use of natural gas as fuel; limit non-emergency use to <= 100 hours per year; adherence to the permittee's operating and maintenance practices	2	G/BHP-HR		0	0	N	
LA-0292	HOLBROOK COMPRESSOR STATION	6	PSD-LA-769(M-1)	Waukesha 16V-275GL Compressor Engines Nos. 1-12	17.13	Natural Gas	5000	HP		Nitrogen Oxides (NOx)	P	Lean-burn combustion, use of natural gas as fuel, good equipment design, and proper combustion techniques	0.45	G/BHP-HR		0	0	N	
MI-0393	RAY COMPRESSOR STATION	5	206-09	Five spark ignition internal combustion engines	17.13	natural gas	32	MMBTU/H	Five (5) natural gas fired spark ignition ICEs; Caterpillar G3616, 4735 hp lean burn engines with 2 way oxidation catalysts.	Nitrogen Oxides (NOx)	N	low emission design and good combustion practices	0			0	0	N	
MI-0393	RAY COMPRESSOR STATION	5	206-09	Emergency generator	17.13	natural gas	500	H/YR	This is an emergency generator which is limited to 500 hours per year of operation.	Nitrogen Oxides (NOx)	N		0			0	0	N	
MI-0401	MIDLAND POWER STATION	5	24-11B	Emergency generator	17.13	Natural gas	1200	KW output	This is a 1200kW (output) natural gas fired emergency generator. The engine was manufactured after 2009	Nitrogen Oxides (NOx)	N		0			0	0	N	
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	5	107-13	Emergency Engine--natural gas (EUNGENGINE)	17.13	natural gas	1000	kW	A 1,000 kilowatts (kW) natural gas-fueled emergency engine manufactured in 2013. The engine is used to charge the batteries in the uninterruptible power supply (UPS) battery system (EUNGENGINE). Restricted to 500 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	P	Good combustion practices	0			0	0	N	
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	5	185-15	EUN_EM_GEN	17.13	Natural gas	225	H/YR	A 1,506 kilowatts (kW) natural gas fueled emergency engine manufactured in 2011 or later. The engine is used to provide electrical power to the station and support equipment in the event power from the public utility grid system is lost (EUN_EM_GEN). Restricted to 225 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	B	Low NOx design (turbo charger and after cooler) and good combustion practices.	0			0	0	N	
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	5	107-13C	EUNGENGINE (Emergency engine--natural gas)	17.13	Natural gas	500	H/YR	A 1,462 HP natural gas-fueled emergency engine manufactured in 2016 serving a 1,040 kW generator. The engine is used to charge the batteries in the uninterruptible power supply (UPS) battery system (EUNGENGINE). Restricted to 144 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	P	Good combustion practices.	0			0	0	N	
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	5	185-15A	EUN_EM_GEN (Natural gas emergency engine).	17.13	Natural gas	205	H/YR	A nominally rated 1,300 electrical kilowatts (ekW) output emergency genset containing a 1,818 HP natural gas fueled engine manufactured in 2011 or later. The engine is used to provide electrical power to the station and support equipment in the event power from the public utility grid system is lost (EUN_EM_GEN). Restricted to 205 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	B	Low NOx design (turbo charger and after cooler) and good combustion practices.	0			0	0	N	
OK-0148	BUFFALO CREEK PROCESSING PLANT	6	2012-1026-C PSD	Large Internal Combustion Engines (>500 hp)	17.13	Natural Gas	1775	Horsepower	Caterpillar G3606LE 4SLB times 6.	Nitrogen Oxides (NOx)	P	Ultra Lean Burn	0			0	0	N	
OK-0148	BUFFALO CREEK PROCESSING PLANT	6	2012-1026-C PSD	Large Internal Combustion Engines (>500 hp)	17.13	Natural Gas	2370	Horsepower	Caterpillar G360BLE 4SLB times 4.	Nitrogen Oxides (NOx)	P	Ultra Lean Burn	0			0	0	N	
OK-0153	ROSE VALLEY PLANT	6	2012-1393-C PSD	COMPRESSOR ENGINE 1,775-HP CAT G3606LE	17.13	NATURAL GAS	1775	HP	THERE ARE TO BE TEN (10) LIKE-KIND ENGINES.	Nitrogen Oxides (NOx)	N		0			0	0	N	
OK-0153	ROSE VALLEY PLANT	6	2012-1393-C PSD	EMERGENCY GENERATORS 2,889-HP CAT G3520C IM	17.13	NATURAL GAS	2889	HP	THERE ARE TO BE TWO (2) ENGINES, EACH EQUIPPED W/AN OXIDATION CATALYST. THESE WILL BE LIMITED USE (< 750 HOURS PER YEAR).	Nitrogen Oxides (NOx)	P	LEAN-BURN COMBUSTION.	0			0	0	N	
PA-0287	WELLING COMPRESSOR STATION	3	63-00958	CATERPILLAR G3516B COMPRESSOR ENGINES (2)	17.13	Natural Gas	0			Nitrogen Oxides (NOx)	N		6.64	T/YR	EACH ENGINE	0	0	N	
PA-0287	WELLING COMPRESSOR STATION	3	63-00958	WAUKESHA P9390GSI COMPRESSOR ENGINES (4) (1980 BHP)	17.13	Natural Gas	0			Nitrogen Oxides (NOx)	A	3-way catalyst, Johnson Matthey	3.82	T/YR	EACH ENGINE	0	0	N	
PA-0297	KELLY IMG ENERGY LLC/KELLY IMG PLT	3	16-161A	3.11 MW GENERATORS (WAUKESHA) #1 and #2	17.13	Natural Gas	0			Nitrogen Oxides (NOx)	N		0			0	0	N	
PA-0301	CARPENTER COMPRESSOR STATION	3	GP5-63-00987	Three Four Stroke Lean Burn Engine - Caterpillar G3608 TA, 2370 BHP	17.13	Natural Gas	0		Controlled by oxidation Catalyst, regulated by automatic air/fuel ratio controllers.	Nitrogen Oxides (NOx)	N		0			0	0	N	
PA-0301	CARPENTER COMPRESSOR STATION	3	GP5-63-00987	One four stroke lean burn engine, Caterpillar Model G3612 TA, 3550 bhp	17.13	Natural Gas	0		Controlled by Oxidation catalyst, regulated by an integrated automatic air/fuel ration controller.	Nitrogen Oxides (NOx)	N		0			0	0	N	
PA-0302	CLERMONT COMPRESSOR STATION	3	GP5-24-180A	Spark Ignited 4 stroke Rich Burn Engine (7 units)	17.13	Natural Gas	0		Spark Ignited 4 stroke Rich Burn Engine (7 units)	Nitrogen Oxides (NOx)	A	NSCR	0			0	0	N	
TX-0642	SINTON COMPRESSOR STATION	6	PSDTX1304	Emergency Engine	17.13	natural gas	1328	hp	1328 horsepower standby generator operating no more than 100 hours per year	Nitrogen Oxides (NOx)	N		0			0	0	N	
TX-0680	SONORA GAS PLANT	6	106139 PSDTX1316	Refrigeration compressor engine	17.13	natural gas	1183	hp	(4) Caterpillar 3516 ultra-lean burn compressor engines at 1,183 hp each	Nitrogen Oxides (NOx)	P	ultra-lean burn technology	0			0	0	N	
TX-0680	SONORA GAS PLANT	6	106139 PSDTX1316	Recompression compressor engine	17.13	natural gas	1380	hp	(8) ultra-lean burn Caterpillar 3516 engines at 1,380 hp each	Nitrogen Oxides (NOx)	P	ultra-lean burn technology	0			0	0	N	
TX-0692	RED GATE POWER PLANT	6	106544 PSDTX1322	(12) reciprocating internal combustion engines	17.13	natural gas	18	MW	12 â€" 18 MW Wartsila 18V50SG natural gas-fired engines, each with an associated electric generator	Nitrogen Oxides (NOx)	A	Selective Catalytic Reduction (SCR)	0			0	0	N	
TX-0755	RAMSEY GAS PLANT	6	117323 AND PSDTX1392_O-3546	Internal Combustion Compressor Engines	17.13	Residue gas equivalent to natural gas	206149	MMBtu/yr	Each cryogenic plant at the Ramsey Gas Plant will have 5 natural gas-fired compressor engines. The residue gas from each plant will be compressed by five compressors.	Nitrogen Oxides (NOx)	P	Ultra Lean-burn engines firing natural gas	0			0	0	N	
WY-0066	MEDICINE BOW IGL PLANT	8	CT-5873	BLACK START GENERATOR 1	17.13	NATURAL GAS	2889	HP	250 HOURS OF OPERATION	Nitrogen Oxides (NOx)	N	LIMITED OPERATING HOURS (250 HR/YR)	0.8	T/YR	ANNUAL	0	0	N	
WY-0066	MEDICINE BOW IGL PLANT	8	CT-5873	BLACK START GENERATOR 2	17.13	NATURAL GAS	2889	HP	LIMITED OPERATING HOURS (250 HR/YR)	Nitrogen Oxides (NOx)	N	LIMITED OPERATING HOURS (250 HR/YR)	0.8	T/YR	ANNUAL	0	0	N	
WY-0066	MEDICINE BOW IGL PLANT	8	CT-5873	BLACK START GENERATOR 3	17.13	NATURAL GAS	2889	HP	LIMITED OPERATING HOURS (250 HR/YR)	Nitrogen Oxides (NOx)	N	LIMITED OPERATING HOURS (250 HR/YR)	0.8	T/YR	ANNUAL	0	0	N	

APPENDIX B – COST ANALYSIS CALCULATIONS

Harvest Four Corners, LLC

Kutz Canyon Processing Plant

Turbine Cost Analysis Interest Rate: 5.50%

All Units Period (yrs): 20

Control Equipment	Unit	Capital Cost ($)	Total Annual Cost* ($)	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Improved Combustion Technology ($SoLoNO_x$)	1	467,300	61,603	27.4	2,246
	2	467,300	61,603	25.5	2,412
	3	467,300	61,603	31.1	1,983
	4	667,300	78,339	3.4	23,111
	5	667,300	78,339	36.5	2,145
	6	667,300	78,339	41.0	1,910
	19	467,300	61,603	12.9	4,779
	20	467,300	61,603	30.1	2,043

* Total Annual Cost includes the annualized capital cost as well as the direct and indirect annual operating costs.

Control Equipment	Unit	Capital Cost ($)	Total Annual Cost* ($)	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Clean Burn Technology	16	1,000,000	123,679	121.1	1,021
	17	1,000,000	123,679	71.7	1,725
	18	1,000,000	123,679	70.0	1,767

* Total Annual Cost includes the annualized capital cost as well as the direct and indirect annual operating costs.

Harvest Four Corners, LLC
Kutz Canyon Processing Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 1	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4002		

Base (67.61 ppm)				
NO_X ppm:		67.61	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:		43.52	tpy	<-- From 2016 EI calculations
SoLoNO_X (25 ppm)				
NO_X guarantee:		25	ppm	<-- from Solar
NO_X tpy:		16.09	tpy	
Total Cap Investment	$	467,300		<-- from Solar
Annualized TCI:	$	39,103		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	22,500		<-- from Solar
Total Annual Costs:	$	61,603		
Emissions Reduction:		27.43	tpy	
Cost Effectiveness:	**$**	**2,245.81**	**$/ton**	

Harvest Four Corners, LLC
Kutz Canyon Processing Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 2	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4002		

Base (67.61 ppm)				
NO_X ppm:		67.61	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:		40.52	tpy	<-- From 2016 EI calculations
SoLoNO$_X$ (25 ppm)				
NO_X guarantee:		25	ppm	<-- from Solar
NO_X tpy:		14.98	tpy	
Total Cap Investment	$	467,300		<-- from Solar
Annualized TCI:	$	39,103		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	22,500		<-- from Solar
Total Annual Costs:	$	61,603		
Emissions Reduction:		25.54	tpy	
Cost Effectiveness:	**$**	**2,412.48**	**$/ton**	

Harvest Four Corners, LLC

Kutz Canyon Processing Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 3	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4002		

Base (67.61 ppm)				
NO_X ppm:		67.61	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:		49.29	tpy	<-- From 2016 EI calculations
SoLoNO$_X$ (25 ppm)				
NO_X guarantee:		25	ppm	<-- from Solar
NO_X tpy:		18.23	tpy	
Total Cap Investment	$	467,300		<-- from Solar
Annualized TCI:	$	39,103		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	22,500		<-- from Solar
Total Annual Costs:	$	61,603		
Emissions Reduction:		31.06	tpy	
Cost Effectiveness:	**$**	**1,983.09**	**$/ton**	

Harvest Four Corners, LLC
Kutz Canyon Processing Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 4	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4002		

Base (67.61 ppm)

NO_X ppm:	67.61	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:	5.38	tpy	<-- From 2016 EI calculations

SoLoNO_X (25 ppm)

NO_X guarantee:	25	ppm	<-- from Solar
NO_X tpy:	1.99	tpy	
Total Cap Investment	$ 667,300		<-- from Solar
Annualized TCI:	$ 55,839		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 22,500		<-- from Solar
Total Annual Costs:	$ 78,339		
Emissions Reduction:	3.39	tpy	
Cost Effectiveness:	**$ 23,110.79**	**$/ton**	

Harvest Four Corners, LLC
Kutz Canyon Processing Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 5	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4002		

Base (67.61 ppm)				
NO_X ppm:		67.61	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:		57.96	tpy	<-- From 2016 EI calculations
SoLoNO$_X$ (25 ppm)				
NO_X guarantee:		25	ppm	<-- from Solar
NO_X tpy:		21.43	tpy	
Total Cap Investment	$	667,300		<-- from Solar
Annualized TCI:	$	55,839		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	22,500		<-- from Solar
Total Annual Costs:	$	78,339		
Emissions Reduction:		36.53	tpy	
Cost Effectiveness:	**$**	**2,144.52**	**$/ton**	

Harvest Four Corners, LLC
Kutz Canyon Processing Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 6	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4002		

Base (67.61 ppm)

NO_X ppm:	67.61	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:	65.08	tpy	<-- From 2016 EI calculations

SoLoNO_X (25 ppm)

NO_X guarantee:	25	ppm	<-- from Solar
NO_X tpy:	24.06	tpy	
Total Cap Investment	$ 667,300		<-- from Solar
Annualized TCI:	$ 55,839		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 22,500		<-- from Solar
Total Annual Costs:	$ 78,339		
Emissions Reduction:	41.01	tpy	
Cost Effectiveness:	**$ 1,910.07**	**$/ton**	

Harvest Four Corners, LLC
Kutz Canyon Processing Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 19	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4001		

Base (67.61 ppm)				
NO_X ppm:		67.61	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:		20.45	tpy	<-- From 2016 EI calculations
SoLoNO$_X$ (25 ppm)				
NO_X guarantee:		25	ppm	<-- from Solar
NO_X tpy:		7.56	tpy	
Total Cap Investment	$	467,300		<-- from Solar
Annualized TCI:	$	39,103		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	22,500		<-- from Solar
Total Annual Costs:	$	61,603		
Emissions Reduction:		12.89	tpy	
Cost Effectiveness:	**$**	**4,779.25**	**$/ton**	

Harvest Four Corners, LLC
Kutz Canyon Processing Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 20	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4001		

Base (67.61 ppm)				
NO_X ppm:		67.61	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:		47.83	tpy	<-- From 2016 EI calculations
SoLoNO$_X$ (25 ppm)				
NO_X guarantee:		25	ppm	<-- from Solar
NO_X tpy:		17.69	tpy	
Total Cap Investment	$	467,300		<-- from Solar
Annualized TCI:	$	39,103		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	22,500		<-- from Solar
Total Annual Costs:	$	61,603		
Emissions Reduction:		30.15	tpy	
Cost Effectiveness:	**$**	**2,043.49**	**$/ton**	

Harvest Four Corners, LLC
Kutz Canyon Processing Plant

Clark HRA-8	Interest Rate:		5.50%	
Unit 16	Period (yrs):		20	<-- EPA Cost Control Manual
	Rating:		723	hp
Base				
NO_X tpy:		151.37	tpy	<-- From 2016 EI calculations
Clean Burn (80% Reduction)[1]				
NO_X tpy:		30.27	tpy	<-- Reduction based on NO_X Emission Controls Doc.[1]
Total Cap Investment	$	1,000,000		<-- Estimate from Harvest
Annualized TCI:	$	83,679		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	40,000		<-- Estimate from Harvest
Total Annual Costs:	$	123,679		
Emissions Reduction:		121.09	tpy	
Cost Effectiveness:	**$**	**1,021.35**	**$/ton**	

[1] From Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Timeline for Compliance (Docket ID No. EPA-HQ-OAR-2015-0500) Section 5.3.

Harvest Four Corners, LLC
Kutz Canyon Processing Plant

Clark HRA-8	Interest Rate:		5.50%	
Unit 17	Period (yrs):		20	<-- EPA Cost Control Manual
	Rating:		723	hp

Base

NO_X tpy:	89.63	tpy	<-- From 2016 EI calculations

Clean Burn (80% Reduction)[1]

NO_X tpy:	17.93	tpy	<-- Reduction based on NO_X Emission Controls Doc.[1]
Total Cap Investment	$ 1,000,000		<-- Estimate from Harvest
Annualized TCI:	$ 83,679		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 40,000		<-- Estimate from Harvest
Total Annual Costs:	$ 123,679		
Emissions Reduction:	71.71	tpy	
Cost Effectiveness:	**$ 1,724.79**	**$/ton**	

[1] From Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Timeline for Compliance (Docket ID No. EPA-HQ-OAR-2015-0500) Section 5.3.

Harvest Four Corners, LLC
Kutz Canyon Processing Plant

Clark HRA-8	Interest Rate:		5.50%	
Unit 18	Period (yrs):		20	<-- EPA Cost Control Manual
	Rating:		723	hp
Base				
NO_X tpy:		87.50	tpy	<-- From 2016 EI calculations
Clean Burn (80% Reduction)[1]				
NO_X tpy:		17.50	tpy	<-- Reduction based on NO_X Emission Controls Doc.[1]
Total Cap Investment	$	1,000,000		<-- Estimate from Harvest
Annualized TCI:	$	83,679		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	40,000		<-- Estimate from Harvest
Total Annual Costs:	$	123,679		
Emissions Reduction:		70.00	tpy	
Cost Effectiveness:	**$**	**1,766.84**	**$/ton**	

[1] From Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Timeline for Compliance (Docket ID No. EPA-HQ-OAR-2015-0500) Section 5.3.

HARVEST MIDSTREAM

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December 13, 2019

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

RE: Submittal Requirements for Process Flaring and Startup, Shutdown, and Maintenance (SSM) Flaring as part of the Regional Haze Four-Factor Analyses

Dear Mr. Singleton:

Harvest Four Corners, LLC is repsonding to the November 14, 2019 request from New Mexico Environment Department for the review of process flaring and Startup, Shutdown, and Maintenance (SSM) flaring as part of the Regional Haze four-factor analyses.

Harvest Four Corners submitted a four-factor analysis for both the Kutz Canyon Processing Plant and San Juan Gas Plant on October 31, 2019. These analyses were conducted in accordance with the federal Clean Air Act, 42 U.S.C. §7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule) as well as the guidance provided by New Mexico Environment Department as received in the July 18, 2019 request to perform four-factor reasonable progress analyses.

Per NMED Guidance from July 18, 2019, *"In accordance with the Regional Haze Rule, NMED requested that a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis."*

The Kutz Canyon Processing Plant has two flares, units 28 and 36. Unit 28 is the plant flare and unit 36 is a control for the TEG dehydrator. The San Juan Gas Plant also has two flares, units 9 and 16. Unit 9 is a plant safety system flare and unit 16 is a staged blowdown flare that works in conjunction with the system flare.

After an extensive review of the equipment at both Kutz Canyon Processing Plant and San Juan Gas Plant it was determined that none of the flares have a potential to emit (PTE) above the de minimus thesholds of 10 pounds per hour and 5 tons per year for either NO_X or SO_2.

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Furthermore, Harvest would like to advise the NMED of their judgement that the flares at both Kutz Canyon and San Juan facilities' potential contribution to regional haze at the Mesa Verde National Park Class I area are such that it does not justify either facility being selected for this assessment for further evaluations of flares. Neither facility has a PTE associated with flares for SO_2 emisions and the NO_X emissions for each flare are below the de minimus thesholds for evaluation. Furthermore, NO_X emissions are not the dominant visibility impairing pollutant at Mesa Verde, and, for that reason, further reductions in NO_X emissions are unlikely to have a significant effect on visibility conditions.

Harvest appreciates the opportunity to present its views on the issues concerning possible reasonable progress assessments for the second planning period of the regional haze program with respect to Harvest Four Corners' Kutz Canyon Processing Plant and San Juan Gas Plant.

If you have questions or require additional information, please contact me at (505) 632-4625 or by e-mail at msmith@harvestmidstream.com.

Sincerely,

Monica Smith
Harvest Four Corners, LLC
MonicaSmith

REGIONAL HAZE FOUR-FACTOR ANALYSIS
NMED FOLLOW-UP LETTER RESPONSE

Harvest Four Corners, LLC, Kutz Canyon Processing Plant

Prepared By:

Adam Erenstein – Manager of Consulting Services
Michael Celente – Senior Consultant
Rachel Reese – Consultant

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March 2020

Project 193201.0199

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Environmental solutions delivered uncommonly well

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The NMED posed the following questions regarding the emissions control options Harvest presented for the turbines and engines located at the Kutz Canyon Processing Plant.

NATURAL GAS FIRED SIMPLE CYCLE TURBINES

i. Provide details of the Good Combustion Practices utilized at the plant including routine inspections, maintenance and training schedules. It is unclear if these practices are fully optimized or conform to permit conditions alone.

Harvest complies with the periodic testing pursuant to A205.A. in order to monitor NOX and CO emissions and A205.D for Maintenance and Repair Monitoring of the current Title V operating permit, P097-R3. A copy of the current SSM Plan includes maintenance and inspection schedules and is included within Appendix B.

Harvest implements good combustion practices as prescribed by the manufacturer and required permit conditions. These include, but are not limited to:

- Manufacturer recommended maintenance
- Training of personnel in proper equipment maintenance and operations
- Routinely scheduled inspections
- Overhauls as required or recommended by the manufacture
- Use of pipeline quality natural gas

i. Provide vendor specifications for the Solar SoLoNOx (i.e., Dry Low NOx (DLN)) combustion technologies to include the guaranteed NOx emission rates used in cost analysis, the cost information, recommendations, and equipment specifications for the turbine control estimates.

These are included in Appendix A.

ii. How will upgrading the turbine combustors with Solar SoLoNOx affect the turbine capacities and the emission rates of NOx and CO?

According to documentation received from Solar, the SoLoNO$_X$ unit would reduce the NO$_X$ exhaust concentration to 15 ppm. According, to AP-42, CO emissions would be increased from the implementation of this control, but Solar has not provided any guidance on the magnitude of the emission increase.[1]

iii. Provide the statement by the turbine vendor stating why water injection is not technically feasible for these units.

This is included in Appendix A.

[1] AP-42 Section 3.1.4.2 Stationary Gas Turbines, Control Technologies, Dry Controls.

iv. Provide supporting data and information for the determination that Selective Catalytic Reduction (SCR) systems are a technically infeasible control measure. Please consider and discuss temperature control devices and catalysts with higher operating temperatures (e.g., zeolites). Additionally, provide clarifying information regarding the additional energy demand SCR would require and expansion of current power generation capacity. Provide a cost analysis if this determination is based on cost and not technical feasibility.

This is included in Appendix A. SCR is not supported by Solar and neither are other proposed technologies – Solar only supports the use of SoLoNO$_X$ for emission reductions on their turbines. Kutz would also need to install additional sources of electricity to meet the power demand required to support SCR.

v. Please consider and include a discussion on limiting turbine operating hours or shutting down turbines that are no longer needed to reduce emissions.

Harvest cannot commit to decreasing turbine capacity as the facility has contractual obligations to process specific amounts of gas. Shutting down units or limiting hours of operation would reduce the facility's capacity and have substantial effects on both producers and consumers of natural gas. Decreases in the maximum capacity could impose a strain on facilities located in the San Juan and this is not something that Harvest can commit to.

vi. Include a discussion of additional control measures for NOx emissions including catalytic combustion and DLN technology available from other manufacturers. A four-factor analysis should be completed for all technically feasible options.

Solar has communicated to Harvest that the only appropriate technology for their turbines is SoLoNO$_X$. Other technologies are not supported by the manufacturer and could impose a serious threat to equipment operation and lead to issues in the future that could lead to more frequent malfunction events. All other DLN technologies are considered technically infeasible for these turbines.

vii. Provide the electronic spreadsheets used for control technology cost calculations.

These have been provided to the NMED.

TWO STROKE LEAN-BURN ENGINES (2SLB)

i. Provide details of the Good Combustion Practices utilized at the plant including routine inspections, maintenance and training schedules.

Harvest complies with Maintenance and Repair Monitoring pursuant to A201.A. and Period Emissions Testing pursuant to A201.B. of the current Title V operating permit, P097-R3. A copy of the current SSM Plan includes maintenance and inspection schedules and is included within Appendix B.

Harvest implements good combustion practices as prescribed by the manufacturer and required permit conditions. These include, but are not limited to:

- Manufacturer recommended maintenance
- Training of personnel in proper equipment maintenance and operations
- Routinely scheduled inspections

- Overhauls as required or recommended by the manufacture
- Use of pipeline quality natural gas

ii. Please consider and include a discussion on the feasibility and cost of technology that limits engine capacity to reduce NOx emissions. Also evaluate limitations on engine operating hours or shutting down engines that are no longer needed to reduce emissions.

Harvest cannot commit to decreasing engine capacity as the facility has contractual obligations to process specific amounts of gas. Shutting down units or limiting hours of operation would reduce the facility's capacity and have substantial effects on both producers and consumers of natural gas. Decreases in the maximum capacity could impose a strain on facilities located in the San Juan and this is not something that Harvest can commit to.

iii. Please consider and include a discussion on the feasibility of replacing the 2SLB engines with commercial electric powered compressors.

40 CFR 51 Appendix Y, states the following: "We do not consider BART as a requirement to redesign the source when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, we do not require the BART analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting on a per unit basis." Moreover, there are concerns regarding the power supply in the San Juan Basin that present some major obstacles in converting these units to electric. This option is therefore not considered.

iv. Consider and include a discussion of variations of Clean Burn Technology (CBT) used to reduce NOx emissions that may be less expensive than the full CBT packages proposed. Please include cost and efficiencies in analysis.

There is limited manufacturer support available to provide input on the potential effect installation of these controls could have on the engines. As such, a third-party control vendor with significantly less unit-specific experience and familiarity would need to be employed to install this control. Harvest is concerned that the addition of this control equipment by a third-party vendor could negatively affect the units and ultimately be operationally detrimental due to their limited historical knowledge of the engines. Despite the potential drawbacks to installation of CBT control on these units discussed above, 2SLB engines are mechanically capable of being retrofit to support the combustor modifications and more sensitive air-to-fuel ratio controllers necessary to employ CBT. Therefore, as stated in the original four factor analysis submitted to NMED it has been determined that this method of NOX control is feasible for the 2SLB engines at Kutz. On 2SLB RICE, CBT is estimated to achieve an 80 to 93% reduction in NOX emissions; however, this reduction is specific to each engine and typical loading.

As the units at Kutz Canyon are two-stroke lean burn engines (2SLB), the technology for reducing NOX emissions are limited. Harvest has requested additional vendor support regarding Clean Burn Technologies (CBT) and is currently still waiting on a response to determine if any other package options would be viable technology for these units.

v. Provide vendor quotes and estimates that include equipment specifications, installation cost information, recommendations, as well as operation and maintenance costs for the engine control estimates in section 3.

Harvest has requested additional vendor support regarding Clean Burn Technologies (CBT) and is currently still waiting on a response for these units.

The cost estimate assumes that the CBT control will reduce NOX emissions by 80%, per the EPA's Alternative Control Techniques document on NOX emissions from stationary RICE.[2]

Provide the technical justification and basis that supports the determination that Clark HRA-8 2SLB are poorly suited for SCR controls resulting in technical complications and unreliable operation. When would the engine control vendor contacted recommend this control?

Harvest has requested additional vendor support regarding SCR and is waiting on a response. Please refer to the discussion within the four-factor analysis section 2.2.2.3. Selective Catalytic Reduction.

For engines that typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia to gain the reductions needed.[3] Kutz does typically operate with variable loads; therefore, the facility expects to have periods of ammonia slip or insufficient ammonia.

In order for the chemical reactions necessary for SCR to occur effectively, the exhaust streams injected with the reagent must be fairly oxygen rich. The exhaust oxygen levels for 2SLB engines are sufficient to support these reactions; therefore, this technology can be used on lean-burn engines.

AP-42 Section 3.2 does list SCR as an available control technology for 2SLB engines; however, the RBLC does not identify SCR as a control for these specific engine models.[4] This is likely because there is limited operating experience to date with the use of SCR on 2SLB RICE. Additionally, there is historical precedent that installation of SCR on 2SLB engines can result in significant technical complications, including a necessity to derate the engines and unreliable operation post-retrofit. The engines at Kutz are currently de-rated to account for the altitude of the facility. It is not operationally appropriate to de-rate the units further, as would be necessary if SCR control is implemented.

An engine control vendor contacted indicated that the Clark HRA-8 model of engines are poorly suited for installation of SCR controls and they do not typically recommend this for control due to the availability of more suitable options, such as CBT. The control vendor stated that significant challenges would need to be overcome to install this equipment on the units. Primarily, the poor air-to-fuel ratio employed in these units will make it difficult to regulate the SCR and greatly affect the NO_X reduction capability out of the engine. Additionally, a turbocharger and intercooler would need to be installed in the units to support the SCR equipment. As SCR control technology is not listed in the RBLC tables for 2SLB engines, has not been a proven as an effective method of controlling NO_X, and has significant operating challenges, Harvest has determined this control is technically infeasible for the Clark HRA-8 engines at Kutz.

---

[2] U.S. EPA, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document – NO_X Emissions from Stationary Reciprocating Internal Combustion Engines", EPA-453/R-93-032, Section 5.2.5.4, July 1993

[3] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"

[4] Ibid.

vi. Please provide more information on what could be done to improve the poor air to fuel ratio for SCR to work properly, including the installation of a turbo charger and intercooler. Provide vendor quotes and specifications received on installing SCR for these engines, if any.

Please refer to the discussion within the four-factor analysis section 2.2.2.3. Selective Catalytic Reduction.

The Clark HRA-8 model of engines are poorly suited for installation of SCR controls and the vendor does not typically recommend this for control due to the availability of more suitable options, such as CBT. The control vendor stated that significant challenges would need to be overcome to install this equipment on the units. Primarily, the poor air-to-fuel ratio employed in these units will make it difficult to regulate the SCR and greatly affect the NO_X reduction capability out of the engine. Additionally, a turbocharger and intercooler would need to be installed in the units to support the SCR equipment. As SCR control technology is not listed in the RBLC tables for 2SLB engines, has not been a proven as an effective method of controlling NO_X, and has significant operating challenges, Harvest has determined this control is technically infeasible for the Clark HRA-8 engines at Kutz.

vii. Provide the electronic spreadsheets used for control technology cost calculations.

These have been provided to the NMED.

APPENDIX A: VENDOR DOCUMENTION

Solar® Turbines

A Caterpillar Company

Powering the Future Through Sustainable, Innovative Energy Solutions

SOLONOX DRY LOW EMISSIONS TECHNOLOGY

Solar Turbines is a leader in pollution-prevention technology. Since the introduction of SoLoNOx™ in 1992, our dry low emissions technology advancements have prevented the production of more than 5.8 MM tons of NOx emissions. This represents a reduction of 75-90% from conventional combustion baselines for natural gas fuel.

Solar has unrivaled experience within the industry with more than 3500 SoLoNOx gas turbines with over 312 million operating hours located around the world.

Fuel options include natural gas, ultra low sulfur diesel (ULSD), associated gases, LPG and kerosene.

Low NOx Emissions Warranty: Pipeline natural gas emissions avalable at 9, 15, 25 or 38 ppm NOx @15% O2 on select models. ULSD emissions levels range from 58 to 96 ppm NOx @15% O2 on select models.

Wide Low NOx Emissions Operating Range: Single shaft 50-100% load, two shaft 40-100% load down to low ambient temperatures.

Available warranty emissions levels, operating range, and ambient temperature range vary by product and rating. Please contact Solar for more information.





Dry Low Emissions 101

DLE (dry low emissions) or lean-premix combustion reduces the conversion of atmospheric nitrogen to NOx by reducing the combustor's flame temperature. Since NOx formation rates are strongly dependent on flame temperature, lowering this temperature is an effective strategy for reducing NOx emissions. Lean combustion is enhanced by premixing the fuel and combustor airflows upstream of the combustory primary zone. DLE eliminates the need for water or steam injection or exhaust cleanup, which benefits the environment at a lower cost.

Additional Information

Internet: **www.solarturbines.com**
Email: **infocorp@solarturbines.com**
Phone: **+1-619-544-5352**

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DSSOLONOX/0419/EO

From: Joey Guillen [mailto:Guillen_Joey@solarturbines.com]
Sent: Monday, February 17, 2020 11:06 PM
To: Monica Smith <msmith@harvestmidstream.com>
Subject: [EXTERNAL] RE: Harvest - 4 Factor San Juan and Kutz

HI Monica,

Please see the attached Product Info Letters (PIL) and Spec Sheets on both the Centaur Generator Set and Compressor set. As well as combustion technology.

As far as wet NOx systems go, it is clearly stated on our spec sheets we no longer offer this technology. It is an outdated technology that requires more parts, maintenance and extremely clean water which equals additional cost for our customer and does not preform as well as our current SoLoNOx technology. Instead we continue to improve on this technology and pass the savings along to our customers from having to maintain additional systems that do not do as well in lowering emissions.

Solar's current stance on SCR's is on a case by case business. However as we are not SCR manufacturers we will currently not warranty or maintain these systems. Being that there are too many ways to construct these types of systems or standardize them based on customer needs, it makes it a difficult avenue for our company to pursue. We stand firm on our SoLoNOx technology being the best solution to lower emissions. It's the most environmentally friendly, cost effective and quickest way to reduce emissions.

FYI I'll be in the FCA office tomorrow morning if you'd like to chat about it. Let me know if this helps. I think I may need to provide you with performance runs to show the emissions guarantees mentioned. However I was waiting to get some clarification from one of our applications engineers before I send that information over.

Thanks!

Cheers,
Joey Guillen
CS – Account Manager
Domestic West Odessa
C: 504-343-0734
O: 432-688-8010
Guillen_Joey@SolarTurbines.com
Solar Turbines Inc.

APPENDIX B: GOOD COMBUSTION PRACTICES

SSM Plan Omitted for Brevity

HARVEST MIDSTREAM

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Houston, TX 77208

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October 23, 2020

Mr. Michael Baca
Control Strategies Manager
New Mexico Environment Department Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico, 87505-1816

Harvest Four Corners, LLC is submitting this response to your August 31, 2020 follow-up email regarding the 4-Factor Analyses for the Kutz Canyon Processing Plant (Kutz) and the San Juan Gas Plant (SJGP). The attachments have been labeled to correspond with each item outlined in your email.

0. Harvest used the 5.5% interest rate based on the default rate at the time of the analysis to estimate costs (2016 year) and you are not opposed to NMED using an updated interest rate (e.g., 3.25%) in our cost analysis.

   While responses to the following items are based on a 5.5% interest rate, Harvest Corporate has recommended that analyses should be based on a 7.5% interest rate, the rate at which money has recently been borrowed.

1. Electronic spreadsheets (i.e., Excel files) and vendor quotes for cost calculations. Harvest indicated that vendor quotes have been difficult to obtain (i.e., CBT for engines) and may not be available, but will provide more information on their efforts to obtain these and the basis to estimate costs.

   See the attached spreadsheet and vendor quotes (*Att1K (filename)*) for the Solar SoLoNOx upgrades for Kutz Canyon. Solar is preparing quotes for the SJGP upgrades. The attached spreadsheet is based the 2019 4-Factor packet submittal, but the vendor quotes were requested after August 31, 2020 conference call.

2. Information for the Kutz Canyon facility (Kutz I) that was shared with our permitting group regarding future plans for permitting, facility operations, shutdowns, etc. With the continuing decline in natural gas production in the San Juan Basin, it is no longer economically viable to operate all equipment at the Kutz Canyon Processing Plant, and thus Harvest will discontinue operation of the Kutz I lean oil plant portion of the facility. The equipment to be decommissioned includes:

   a. Unit 16 – Clark HRA8 refrigerant compressor R4;
   b. Unit 17 – Clark HRA8 refrigerant compressor R5;
   c. Unit 18 – Clark HRA8 refrigerant compressor R6;
   d. Unit 22 – 23.1 MMBtu/hr Wheco heater H1;

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e. Unit 23 – 9.57 MMBtu/hr Alcorn heater H2;
f. Unit 24a – Kutz I EG dehydrator;
g. Unit 24b – Kutz I dehydrator reboiler;
h. Unit 37a – Waukesha 5794LT refrigerant compressor;
i. Unit 37b – Waukesha 7042GL refrigerant compressor (never installed);
j. Unit 39 – cooling tower; and
k. Tank T6438 – Blanco/Hare condensate tank and associated EVRU

3. Clarification about the use and generation of electricity at each plant including a list of the units used for compression and generating electricity.
   a. At Kutz, as currently permitted, Units 1 through 8, 16, 17 and 18 compress inlet or residue gas, while Units 37a or 37b compress propane for the Kutz 1 lean oil plant. Units 29 and 30 (Gen A and Gen B) generate electricity.
   b. At SJGP, Units 1, 2 and 3 compress inlet and residue gas, while electricity is generated by Units 4, 5, 6 and 7.

4. Technically feasibility of installing line electricity to the plants and replacing compression units with electric motors. Attachments *Att4K Kutz Electrical 9.8.2020* and *Att4S SJ Electrical Conversion* provide the cost estimate of replacing gas-fired compressor drivers with electrical motors.
   Adding 3 VFD motors to replace the units used for compression only, would require 15,000 hp motor variable speed for each. A building housing the three VFD motors of that size would have to be built across the road with land purchase. The power currently produced wouldn't be near enough for one VFD motor, much less all three. This would require a substation to be built across the road also. Modifications to the plant would have to be made, and real estate found to have heaters installed for heating the hot oil, which currently uses the waste heat from the turbines. Without the hot oil, the plant cannot make product spec. Additionally, these type and size of motors with a substation to start them would probably require very high voltage technicians that are qualified to work on them; nobody currently working at SJGP is line voltage qualified.

5. Confirmation that retrofit costs were included in your SCR analysis for the Solar turbines at San Juan GP.
   The SCR cost were derived using the EPA Cost Control Manual for SCRs. Within this calculation is an option for retrofit which was chosen and a designation of a Retrofit Factor (RF). An RF of 1.o was chosen for this calculation which is incorporated for the cost. Based on the Chapter 2 Selective Catalytic Reduction" from June 2019 , "a retrofit factor of 1 should be used for average retrofits. The equations may overestimate costs for

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some simple retrofits of existing plants. For retrofits that are more complicated than average, a retrofit factor of greater than 1 can be used to estimate capital costs provided the reasons for using a higher retrofit factor are appropriate and fully documented."

6. Clarification on the basis and use of incremental costs for SCR.
   Upon evaluating the calculation for incremental cost this appears to only be the difference in cost between the installation of SoloNox versus SCR and does not change the individual evaluation of the cost of the SCR.

7. Additional information about the space limitations for installing SCR.
   As with conversion to electricity, installation of SCR for turbine exhaust controls would also require purchase of real estate across the road. Routing the turbine exhaust to the ammonia/urea reagent storage across the road is technically infeasible the exhaust temperature would fall below reaction temperatures. Therefore, it would be necessary to pump the reagent to the existing exhaust stacks that have been retrofitted to accommodate the catalyst. In addition to the costs of remotely storing the reagent, there is also a significant safety hazard moving the reagent from storage and across the road to the exhaust stacks.

Thank you for your assistance with this analysis. Please email or call me (msmith@harvestmidstream.com, (505) 632-4625) if we can provide any additional information.

Sincerely,

Monica Smith

Monica Smith
Environmental Specialist

Attachments

Attachments Containing Confidential Vendor Information Omitted

Budget Summary

Program: Kutz Plant Electrification

	Item	Work Order	Type	QY	Original Baseline Budget	Budget at Completion
FEUS	New Electrical Sub-Station		Project	1	20,000,000.00	20,000,000.00
Kutz	Project Engineering & Design		Project	1	150,001.00	150,001.00
Kutz	Internal Labor		Project	1	100,000.00	100,000.00
Kutz	Arc Flash Study		Project	1	75,000.00	75,000.00
Kutz	UPS & Batteries Upgrades		Project	1	78,000.00	78,000.00
Kutz	Grounding Beds		Project	1	150,000.00	150,000.00
Kutz	Land Survey		Project	1	10,000.00	10,000.00
Kutz	Construction (Kutz Plant)		Project	1	1,000,000.00	1,000,000.00
Kutz	New Motor, VFD, Transformer		Project	6	2,500,000.00	15,000,000.00
Kutz	FEUS (Farmington Electrical Utility System)		Project	1	250,000.00	250,000.00
Kutz	New Conduit, Junction Boxes, Breaks		Project	Various	100,000.00	300,000.00
Kutz	Compressor Gearbox		Project	6	500,000.00	3,000,000.00
Kutz	DCS Upgrades		Project	6	100,000.00	600,000.00
	Kutz Medium Voltage Maintenance					
Kutz	Monthly Electric Service Bill		Reoccurring	12	100,000.00	1,200,000.00
Kutz	Medium Voltage Electrical Maintenance		Reoccurring	12	8,000.00	96,000.00
Kutz	Training Personnel (Medium Voltage 13.8kV)		Reoccurring	2	10,000.00	20,000.00
Kutz	Contingency		Project	1	2,000,000.00	2,000,000.00
					27,131,001.00	44,029,001.00

From: Monica Smith <msmith@harvestmidstream.com>
Sent: Friday, February 26, 2021 1:55 PM
To: Baca, Michael, NMENV
Cc: Jones, Mark, NMENV
Subject: [EXT] RE: [EXTERNAL] RE: Harvest 4FAs Follow-up Discussion
Attachments: Harvest - Pricing Term Sheet (Final).pdf; OD21_5029_LE_Harvest_San Juan Sta G-1300A Controls Upgrade.pdf; OD21_5030_LE_Harvest_San Juan Sta G-1300B Controls Upgrade.pdf; OD21_5031_LE_Harvest_San Juan Sta G-1300C Controls Upgrade.pdf; OD21_5032_LE_Harvest_San Juan Sta G-1300D Controls Upgrade.pdf; OD20-27963 Harvest Midstream San Juan Gens NOx_PSU Conversions201014JLG.PDF

Follow Up Flag: Follow up
Flag Status: Flagged

Michael,

Please see the attached items as well as the responses provided below.

1.) Harvest used a 5.5% interest rate in their responses and indicated that Harvest Corporate recommends a 7.5% interest rate for use in the 4-Factor Analyses. We have to document company specific interest rates in the form of a letter from the chief financial officer for the institution that lends to your company, or from an official with your company (your company's CFO, for instance) that is in a position to know your company's costs of debt and equity. Otherwise, we plan to use the current prime rate of 3.25% in the cost calculations. – Harvest – Pricing Term Sheet, attached

2.) Have you received quotes from Solar for the SJGP upgrades? – (5) attachments included from Solar for San Juan Gas Plant, (all 5 docs start with OD)

3.) Harvest indicates that equipment associated with the lean oil plant of Kutz I will be decommissioned. Under the Regional Haze Rule, emission limitations and reductions must be permanent and federally enforceable. Our review of Air Quality Bureau's permitting records does not show a recent New Source Review permit application for this action. Please provide more information about your plans to modify your permits including any recent communications with AQB permitting staff indicating your commitment to permanently discontinue operation of the Kutz I lean oil plant. – We just started internal discussions about the removal of the Kutz I equipment. We felt that we needed to wait before proceeding with the permit application to ensure that the plant could operate without any issues before de-permitting the equipment. Internal discussions have begun, and communications with NMED will be upcoming as well as the application submittal. We are currently working through our Annual Reports, such as Emissions Inventory and Green House Gas, which take precedent based on the submittal deadlines.

This is the current list of equipment that we plan on removing from the Kutz Permit, we may be adding a couple more items, in the permit application.

EU	Equipment Name
16	Clark Reciprocating Engine (R4)
17	Clark Reciprocating Engine (R5)
18	Clark Reciprocating Engine (R6)
22	Wheco Heater (H1)

23	Alcorn Heater (H2)
24	Kutz I EG Dehydrator
37a	Waukesha L5794LT Engine refrigerant compressor
37b	Waukesha L7042GL Engine (never installed)
39	Cooling Tower
T6438	Blanco-Hare Condensate Tank (& EVRU)

4.) Do the Operation and Maintenance (O&M) costs provided for in your Four Factor evaluation of applicable equipment reflect the incremental cost of O&M for additional control? In other words, are these costs over and above those already realized for the units? – Both Plant Foreman feel as though the numbers provide are correct. They did not feel that the numbers provided were over and above the cost already realized for the units.

Please let me know if you have any additional questions or need additional information.

Thank you,

Monica Smith
Harvest Four Corners, LLC
msmith@harvestmidstream.com
(505) 632-4625 - office
(505) 947-1852 - cell

Confidential Term Sheet Omitted

From: Monica Smith <msmith@harvestmidstream.com>
Sent: Monday, August 28, 2023 3:04 PM
To: Olson, Kirby, ENV
Cc: Baca, Michael, ENV; Jones, Mark, ENV; Miller, Kenneth, ENV; Butt, Neal, ENV; Bob Sidner
Subject: RE: [EXTERNAL] Follow up on Kutz Canyon and the regional haze program
Attachments: Harvest - Pricing Term Sheet (Final).pdf; Att4k Kutz Electrical 9.8.2020 (2).xlsx

My apologies for the delayed follow up to our conference call.

After speaking with upper management, they have advised that we still have the same pricing sheet previously provided with a 7.5% interest rate. I have attached the letter that was previously provided.

The same for the electrification after further review of what was submitted, Harvest will not be revising the cost elevation. Also attached.

Below are the updated cost of capital associated with the Solar turbines currently located at Kutz Plant.

Conventional units
4 year overhaul costs per unit- $513,282.00

Maintenance cost per year-$128,320.00 per unit

Solonox upgrade- 750k per unit

Solonox units
4 year overhaul costs- $630,000 per unit

Maintenance cost per year-$157,520 per unit

Please let me know if you have any additional questions or need anything else.

Thank you,

Monica Smith
Environmental Specialist
Harvest Four Corners, LLC
msmith@harvestmidstream.com
505-632-4625 (office)
505-947-1852 (cell)

Previously Provided Attachments Omitted

From: Monica Smith <msmith@harvestmidstream.com>
Sent: Thursday, February 22, 2024 2:05 PM
To: Olson, Kirby, ENV
Cc: Jones, Mark, ENV; Miller, Kenneth, ENV; Sanchez, Alex, ENV
Subject: RE: [EXTERNAL] Question Regarding Status of Kutz Canyon Processing Plant Units 4-6, Other Facility Changes

Kirby,

My apologies for the delay in getting back to you. Units 4-6 remain inactive with no plans to bring those units online or make the necessary changes needed to get them up and running. No final decision has been made to remove the no longer operating equipment from the permit. Units 19-20 are still providing power for the facility, communications and progress on the purchase power route have been unsuccessful and may be a few years out. The flare is being looked at per Ozone rule requirements, so no decision has been made there. With all this said I feel like it will still be a year or two before we are able to re-permit the facility as a minor source.

Please let me know if you have any additional questions.

Thank you,

Monica Smith
Environmental Specialist
Harvest Four Corners, LLC
msmith@harvestmidstream.com
505-632-4625 (office)
505-947-1852 (cell)
HARVEST MIDSTREAM

D.8 Hilcorp Energy Company

Supporting documentation for Hilcorp Energy Company is provided below. Facility-specific documentation is provided first, followed by documentation pertaining to multiple facilities and/or the owner/operator. The following documents are included in this section (in reading order):

- San Juan Basin Gas Plant:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (11/2019)
    - Information Regarding Process & SSM Flaring (12/13/2019)
    - Follow-Up Submittal (3/2020)
    - Follow-Up Submittal (10/23/2020)
    - Follow-Up Submittal (2/26/2021)
    - Follow-Up Submittal (7/31/2023)

NMED Final Cost Evaluation
Hilcorp Energy Company - San Juan Basin Gas Plant

Facility Information

Hilcorp - San Juan Gas Plant	**Facility**
Three 1980s Rolls-Royce Avon 1535 CTs	**Units**
1, 2 and 3	**Unit IDs**
DLE Upgrade	**Evaluated Pollution Control**
25	**Post-control Emissions Rate (ppmvd NOx)**

Supporting Information

2023	**Calendar year associated with cost estimates**
15000	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 1	Unit 2	Unit 3	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	Included in TCC
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	Included in TCC
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	Included in TCC
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	Included in TCC
Total Capital Costs - Direct ($)	TCC	$ 4,500,000	$ 4,500,000	$ 4,500,000	Hilcorp July 2023 update	Vendor estimate; may not include everything required
Additional Capital ($)	AC	$ -	$ -	$ -	-	Not specified by Hilcorp
Total Capital Investment ($)	TCI	$ 4,500,000	$ 4,500,000	$ 4,500,000	-	TCC + AC
Interest Rate (%)	R	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	Hilcorp did not provide a company-specific interest rate
Useful Life (yr)	Y	20	20	20	Manufacturer	Consistent with other FFAs
Capital Recovery Factor	CRF	0.0981	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 441,415	$ 441,415	$ 441,415	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 210,000	$ 210,000	$ 210,000	Hilcorp July 2023 update	Incremental maintenance and overhaul costs
Other Indirect Annual Costs ($/yr)	OAC	$ 180,000	$ 180,000	$ 180,000	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 831,415	$ 831,415	$ 831,415	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	3%	4%	-0.2%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate; Negative control efficiency and cost effectiveness due to the current emissions rate being less than the assumed post-control rate of 25 ppm.
Baseline Actual NOx Emissions (ton/yr)	BAE	83.6	90.4	83.1	CY 2022 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Hilcorp
Projected Actual Emissions (ton/yr)	PAE	83.6	90.4	83.1	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	2.4	3.5	-0.2	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 350,575**	**$ 236,827**	**-$4,990,263**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January - September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 350,575**	**$ 236,827**	**-$4,990,263**	-	CE1 x PI

NMED Final Cost Evaluation
Hilcorp Energy Company - San Juan Basin Gas Plant

Facility Information

Hilcorp - San Juan Gas Plant	**Facility**
Four 1980s Solar Centaur T4501 CTs	**Units**
4, 5, 6, and 7	**Unit IDs**
SoLoNOx	**Evaluated Pollution Control**
25	**Post-control Emissions Rate (ppmvd NOx)**

Supporting Information

2023	**Calendar year associated with cost estimates**
3735	**Maximum/Permitted Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 4	Unit 5	Unit 6	Unit 7	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	$ -	-	Included in TCC
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	$ -	-	Included in TCC
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	$ -	-	Included in TCC
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	$ -	-	Included in TCC
Total Capital Costs - Direct ($)	TCC	$ 1,740,622	$ 1,740,622	$ 1,740,622	$ 1,740,622	Hilcorp July 2023 update	Quote from vendor: Solar Turbines
Additional Capital ($)	AC	$ -	$ -	$ -	$ -	Not specified by Hilcorp	
Total Capital Investment ($)	TCI	$ 1,740,622	$ 1,740,622	$ 1,740,622	$ 1,740,622	-	TCC + AC
Interest Rate (%)	R	7.50%	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	Hilcorp did not provide a company-specific interest rate
Useful Life (yr)	Y	20	20	20	20	Manufacturer	Consistent with other FFAs
Capital Recovery Factor	CRF	0.0981	0.0981	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 170,741	$ 170,741	$ 170,741	$ 170,741	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 109,525	$ 109,525	$ 109,525	$ 109,525	Hilcorp July 2023 update	Incremental maintenance and overhaul costs
Other Indirect Annual Costs ($/yr)	OAC	$ 69,625	$ 69,625	$ 69,625	$ 69,625	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 349,891	$ 349,891	$ 349,891	$ 349,891	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	68%	69%	71%	71%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	55.6	55.0	60.9	56.8	CY 2022 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	-	Not requested by Hilcorp
Projected Actual Emissions (ton/yr)	PAE	55.6	55.0	60.9	56.8	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	38.1	37.7	43.2	40.2	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 9,183**	**$ 9,277**	**$ 8,101**	**$ 8,712**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January - September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 9,183**	**$ 9,277**	**$ 8,101**	**$ 8,712**	-	CE1 x PI

NMED Final Cost Evaluation
Hilcorp Energy Company - San Juan Basin Gas Plant

Facility Information

Hilcorp - San Juan Gas Plant	**Facility**
Three 1980s Rolls-Royce Avon 1535 CTs	**Units**
1, 2 and 3	**Unit IDs**
SCR	**Evaluated Pollution Control**

Supporting Information

2024	**Calendar year associated with cost estimates**
15000	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 1	Unit 2	Unit 3	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 5,803,002	$ 5,803,002	$ 5,803,002	EPA SCR Tool (2024$)	Likely underestimates total costs; does not include construction and engineering costs needed to create physical space.
Interest Rate (%)	R	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	Hilcorp did not provide a company-specific interest rate
Useful Life (yr)	Y	20	20	20	EPA Cost Manual	
Capital Recovery Factor	CRF	0.0981	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 569,229	$ 569,229	$ 569,229	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 115,230	$ 116,901	$ 116,046	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 2,976	$ 2,976	$ 2,976	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 687,435	$ 689,106	$ 688,251	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	80%	80%	80%	EPA SCR Tool	Consistent with EPA and industry documentation.
Baseline Actual NOx Emissions (ton/yr)	BAE	83.6	90.4	83.1	CY 2022 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Hilcorp
Projected Actual Emissions (ton/yr)	PAE	83.6	90.4	83.1	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	66.9	72.3	66.5	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 10,280**	**$ 9,528**	**$ 10,348**	-	TAC/ER

NMED Final Cost Evaluation
Hilcorp Energy Company - San Juan Basin Gas Plant

Facility Information

Hilcorp - San Juan Gas Plant	**Facility**
Four 1980s Solar Centaur T4501 CTs	**Units**
4, 5, 6, and 7	**Unit IDs**
SCR	**Evaluated Pollution Control**

Supporting Information

2024	**Calendar year associated with cost estimates**
3735	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 4	Unit 5	Unit 6	Unit 7	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 1,998,547	$ 1,998,547	$ 1,998,547	$ 1,998,547	EPA SCR Tool (2024$)	Likely underestimates total costs; does not include construction and engineering costs needed to create physical space.
Interest Rate (%)	R	7.50%	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	Hilcorp did not provide a company-specific interest rate
Useful Life (yr)	Y	20	20	20	20	EPA Cost Manual	
Capital Recovery Factor	CRF	0.0981	0.0981	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 196,042	$ 196,042	$ 196,042	$ 196,042	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 32,435	$ 32,410	$ 33,301	$ 32,459	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 2,748	$ 2,748	$ 2,748	$ 2,748	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 231,225	$ 231,200	$ 232,091	$ 231,249	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	80%	80%	80%	80%	EPA SCR Tool	Consistent with EPA and industry documentation.
Baseline Actual NOx Emissions (ton/yr)	BAE	55.6	55.0	60.9	56.8	CY 2022 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	-	Not requested by Hilcorp
Projected Actual Emissions (ton/yr)	PAE	55.6	55.0	60.9	56.8	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	44.5	44.0	48.7	45.5	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 5,196**	**$ 5,250**	**$ 4,761**	**$ 5,087**	-	TAC/ER

NMED Final Cost Evaluation
Hilcorp Energy Company - San Juan Basin Gas Plant

Facility Information

Hilcorp - San Juan Gas Plant	**Facility**
Three 1980s Rolls-Royce Avon 1535 CTs	**Units**
1, 2 and 3	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
15	**Post-control Emissions Rate (ppmvd @ 15% O2)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired CT >=4,100 hp and <15,900 hp.

Additional Information

2023	**Calendar year associated with cost estimates**
15000	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 1	Unit 2	Unit 3	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 48,601,800	$ 48,601,800	$ 48,601,800	9/8/20 info from El Paso Natural Gas (2020$ converted to 2023$ with CEPCI)	All-in estimate ($/HP) x Maximum Capacity (HP); Using EPNG's $2418/hp cost metric as Hilcorp did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered CT.
Interest Rate (%)	R	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	Hilcorp did not provide a company-specific interest rate
Useful Life (yr)	Y	30	30	30	ERG experience based on discussions with CT manufacturers	
Capital Recovery Factor	CRF	0.0847	0.0847	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 4,115,174	$ 4,115,174	$ 4,115,174	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 210,000	$ 210,000	$ 210,000	Hilcorp July 2023 update	Incremental maintenance and overhaul costs for units with DLE
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 4,325,174	$ 4,325,174	$ 4,325,174	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	42%	42%	40%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	83.6	90.4	83.1	CY 2022 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Hilcorp
Projected Actual Emissions (ton/yr)	PAE	83.6	90.4	83.1	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	34.9	38.3	33.2	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 124,077**	**$ 113,019**	**$ 130,454**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January - September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 124,077**	**$ 113,019**	**$130,454**	-	CE1 x PI

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Hilcorp Energy Company - San Juan Basin Gas Plant

Facility Information

Hilcorp - San Juan Gas Plant	**Facility**
Four 1980s Solar Centaur T4501 CTs	**Units**
4, 5, 6, and 7	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
25.0	**Post-control Emissions Rate (ppmvd @ 15% O2)***

*Consistent with manufacturer specifications for similar, new CT equipped with DLN.

Additional Information

2023	**Calendar year associated with cost estimates**
3735	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Unit 4	Unit 5	Unit 6	Unit 7	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 12,101,848	$ 12,101,848	$ 12,101,848	$ 12,101,848	9/8/20 info from El Paso Natural Gas (2020$ converted to 2023$ with CEPCI)	All-in estimate ($/HP) x Maximum Capacity (HP); Using EPNG's $2418/hp cost metric as Hilcorp did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered CT.
Interest Rate (%)	R	7.50%	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	Hilcorp did not provide a company-specific interest rate
Useful Life (yr)	Y	30	30	30	30	ERG experience based on discussions with CT manufacturers	
Capital Recovery Factor	CRF	0.0847	0.0847	0.0847	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 1,024,678	$ 1,024,678	$ 1,024,678	$ 1,024,678	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 109,525	$ 109,525	$ 109,525	$ 109,525	Hilcorp July 2023 update	The result of substantially higher overhaul costs
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 1,134,203	$ 1,134,203	$ 1,134,203	$ 1,134,203	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	68%	69%	71%	71%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	55.6	55.0	60.9	56.8	CY 2022 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	-	Not requested by Hilcorp
Projected Actual Emissions (ton/yr)	PAE	55.6	55.0	60.9	56.8	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	38.1	37.7	43.2	40.2	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 29,769**	**$ 30,073**	**$ 26,260**	**$ 28,241**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January - September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 29,769**	**$ 30,073**	**$ 26,260**	**$ 28,241**	-	CE1 x PI

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Hilcorp Energy Company - San Juan Basin Gas Plant

Facility Information

Hilcorp - San Juan Gas Plant	**Facility**
Three 1980s Rolls-Royce Avon 1535 CTs	**Units**
1, 2 and 3	**Unit IDs**
Replacement with EMD	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
15000	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		Units 1, 2, and 3	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 17,250,000	Hilcorp July 2023 update	Motors and enclosures, gear boxes, VFD etc.
Other Direct Capital Costs 1 ($)	ODC1	$ 8,510,000	Hilcorp July 2023 update	Installation costs
Other Direct Capital Costs 2 ($)	ODC2	$ 1,080,000	Hilcorp July 2023 update	Crane rental
Indirect Capital Costs ($)	IDC	$ 2,684,000	Hilcorp July 2023 update	10% contingency
Total Capital Costs - Direct ($)	TCC	$ 29,524,000	-	PEC + ODC1 + ODC2 + IDC
Additional Capital ($)	AC	$ 38,000,000	Farmington Electric Utility letter dated 7/20/23	New substation and 20 miles of new T-line @ $1M/mile
Total Capital Investment ($)	TCI	$ 67,524,000	-	TCC + AC
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	Hilcorp did not provide a company-specific interest rate
Useful Life (yr)	Y	25	Other FFAs	
Capital Recovery Factor	CRF	0.0897	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 6,057,623	-	
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 9,064,465	-	OC + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 18,128,930	ERG calculation	Assumes 60% load, 95% efficiency and a $0.10/kWh price
Associated non-electricity O&M ($/yr)	AOM	$ -	Engineering judgement	Incremental O&M reasonably negligible
Annual Fuel Credit ($/yr)	AFC	$ (9,064,465)	ERG calculation	Assumes fuel savings is 50% of AED
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 15,122,088	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	485.6	CY 2022 emissions testing and average operating hours (2016-2021)	Sum of BAE of Units 1-7; assumes line power would obviate the need for generators and units 4-7 would be retired
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by Hilcorp
Projected Actual Emissions (ton/yr)	PAE	485.6	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	485.6	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 31,144**	-	TAC/ER
Price Index	PI	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January - September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 31,144**	-	CE1 x PI

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Unit 1: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	123.2	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	1,007,467,701	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5595	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.1610	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0322	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F		*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour		

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 1: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	123	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,046,781,765	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,007,467,701	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.962	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8431	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	15.86	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	66.87	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	458.30	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	6	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	21	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,000	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	72.94	kW

Unit 1: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$5,803,002	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$115,230 in 2024 dollars
Indirect Annual Costs (IDAC) =	$572,251 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$687,481 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$29,015 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$12,666 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$61,492 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$12,057 in 2024 dollars
Direct Annual Cost =		$115,230 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,976 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$569,275 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$572,251 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$687,481 per year in 2024 dollars
NOx Removed =	67 tons/year
Cost Effectiveness =	$10,280 per ton of NOx removed in 2024 dollars

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Hilcorp Energy Company - San Juan Basin Gas Plant

Unit 2: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	123.2	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	1,017,146,848	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5595	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.1724	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0345	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F		*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour		

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 2: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	123	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,046,781,765	scf/Year
Actual Annual fuel consumption (Mactual) =		1,017,146,848	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.972	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8512	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	16.99	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	72.32	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

Not applicable; factor applies only to coal-fired boilers

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	460.16	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	7	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	23	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,100	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	72.94	kW

Unit 2: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$5,803,002	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$116,901 in 2024 dollars
Indirect Annual Costs (IDAC) =	$572,251 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$689,151 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$29,015 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$13,697 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$62,083 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$12,106 in 2024 dollars
Direct Annual Cost =		$116,901 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,976 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$569,275 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$572,251 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$689,151 per year in 2024 dollars
NOx Removed =	72 tons/year
Cost Effectiveness =	$9,529 per ton of NOx removed in 2024 dollars

NMED Final Cost Evaluation
Hilcorp Energy Company - San Juan Basin Gas Plant

Unit 3: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	123.2	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	1,022,165,664	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5595	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.1578	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0316	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 3: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	123	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,046,781,765	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,022,165,664	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.976	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8554	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	15.55	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	66.52	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	457.79	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	6	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	21	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,000	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	72.94	kW

Unit 3: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$5,803,002	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$116,046 in 2024 dollars
Indirect Annual Costs (IDAC) =	$572,251 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$688,296 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$29,015 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$12,598 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$62,389 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$12,043 in 2024 dollars
Direct Annual Cost =		$116,046 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,976 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$569,275 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$572,251 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$688,296 per year in 2024 dollars
NOx Removed =	67 tons/year
Cost Effectiveness =	$10,348 per ton of NOx removed in 2024 dollars

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Unit 4: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	23.9	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	185,613,288	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5595	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.5812	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1162	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours	
Estimated SCR equipment life	20	Years*	

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F	*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour	

Concentration of reagent as stored (C_{stored})	29	percent*	
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*	
Number of days reagent is stored ($t_{storage}$)	14	days	

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 4: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	24	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	203,068,865	scf/Year
Actual Annual fuel consumption (Mactual) =		185,613,288	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.914	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8007	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	11.11	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	44.49	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	102.16	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	4	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	15	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	700	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	14.15	kW

Unit 4: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$1,998,547	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$32,435 in 2024 dollars
Indirect Annual Costs (IDAC) =	$198,805 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$231,241 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$9,993 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$8,426 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$11,329 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$2,688 in 2024 dollars
Direct Annual Cost =		$32,435 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,748 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$196,057 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$198,805 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$231,241 per year in 2024 dollars
NOx Removed =	44 tons/year
Cost Effectiveness =	$5,198 per ton of NOx removed in 2024 dollars

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Unit 5: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	23.9	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	186,772,357	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5595	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.5715	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1143	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours	
Estimated SCR equipment life	20	Years*	

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F	*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour	

Concentration of reagent as stored (C_{stored})	29	percent*	
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*	
Number of days reagent is stored ($t_{storage}$)	14	days	

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 5: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	24	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	203,068,865	scf/Year	
Actual Annual fuel consumption (Mactual) =		186,772,357	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.920	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8057	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	10.93	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	44.02	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	101.86	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	4	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	15	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	700	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	14.15	kW

Unit 5: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$1,998,547	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$32,410 in 2024 dollars
Indirect Annual Costs (IDAC) =	$198,805 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$231,216 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$9,993 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$8,338 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$11,400 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$2,680 in 2024 dollars
Direct Annual Cost =		$32,410 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,748 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$196,057 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$198,805 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$231,216 per year in 2024 dollars
NOx Removed =	44 tons/year
Cost Effectiveness =	$5,252 per ton of NOx removed in 2024 dollars

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Unit 6: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	23.9	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	185,845,102	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5595	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.6360	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1272	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

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Unit 6: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	24	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	203,068,865	scf/Year
Actual Annual fuel consumption (Mactual) =		185,845,102	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.915	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8017	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	12.16	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	48.74	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	103.89	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole
Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	5	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	16	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	800	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	14.15	kW

Unit 6: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$1,998,547	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$33,301 in 2024 dollars
Indirect Annual Costs (IDAC) =	$198,805 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$232,107 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$9,993 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$9,232 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$11,343 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$2,733 in 2024 dollars
Direct Annual Cost =		$33,301 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,748 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$196,057 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$198,805 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$232,107 per year in 2024 dollars
NOx Removed =	49 tons/year
Cost Effectiveness =	$4,762 per ton of NOx removed in 2024 dollars

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Unit 7: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	23.9	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	182,692,435	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	5595	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.6033	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1207	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

NMED Final Cost Evaluation
Hilcorp Energy Company - San Juan Basin Gas Plant

Unit 7: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	24	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	203,068,865	scf/Year
Actual Annual fuel consumption (Mactual) =		182,692,435	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.900	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7881	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	11.54	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	45.46	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	102.86	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole
Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	4	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	15	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	700	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	14.15	kW

Unit 7: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$1,998,547	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$32,459 in 2024 dollars
Indirect Annual Costs (IDAC) =	$198,805 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$231,265 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$9,993 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$8,610 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$11,151 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$2,706 in 2024 dollars
Direct Annual Cost =		$32,459 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,748 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$196,057 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$198,805 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$231,265 per year in 2024 dollars
NOx Removed =	45 tons/year
Cost Effectiveness =	$5,087 per ton of NOx removed in 2024 dollars

REGIONAL HAZE FOUR-FACTOR ANALYSIS

Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant

Prepared By:

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1. EXECUTIVE SUMMARY

In the 1977 amendments to the Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across the United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

> *(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A).*
>
> This is known as a four-factor analysis.
>
> *(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B).*
>
> The uniform rate of progress or improvement is sometimes referred to as the glidepath and is part of the state's Long-Term Strategy (LTS).

The second implementation planning period (2018-2028) for national regional haze efforts is currently underway. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural or biogenic and manmade or anthropogenic sources of emissions. Using a Photochemical Grid Model (PGM), the Western Region Air Partnership (WRAP), in coordination with the EPA, is tasked with comparing anthropogenic source contributions against natural background concentrations.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for major sources and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I area. From this analysis, 24 facilities were identified by the NMED. On July 18, 2019 the NMED informed Harvest Four Corners, LLC (Harvest) that its Harvest Pipeline - San Juan Gas Plant (San Juan) facility was identified as one of the sources potentially contributing to regional haze at the Mesa Verde National Park Class I area.

In coordination with WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. In the NMED's July 18, 2019 notification letter to Harvest, it specifies that any equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The subject equipment at San Juan, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant are reported in Table 1.

Table 1. Summary of Equipment and Applicability to a Four-Factor Analysis

Equipment	NO_X Hourly PTE (lb/hr)	NO_X Annual PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
Rolls-Royce Avon 1535 Natural Gas Turbine (Unit 1)	56.3	246.4	Yes	0.060	0.26	No
Rolls-Royce Avon 1535 Natural Gas Turbine (Unit 2)	56.3	246.4	Yes	0.060	0.26	No
Rolls-Royce Avon 1535 Natural Gas Turbine (Unit 3)	56.3	246.4	Yes	0.060	0.26	No
Rolls-Royce Avon 1535 Natural Gas Turbine (Unit Rotating Spare)	56.3	246.4	Yes	0.060	0.26	No
Solar Centaur T4501 Natural Gas Turbine (Unit 4)	15.9	69.8	Yes	0.010	0.050	No
Solar Centaur T4501 Natural Gas Turbine (Unit 5)	15.9	69.8	Yes	0.010	0.050	No
Solar Centaur T4501 Natural Gas Turbine (Unit 6)	15.9	69.8	Yes	0.010	0.050	No
Solar Centaur T4501 Natural Gas Turbine (Unit 7)	15.9	69.8	Yes	0.010	0.050	No

Once the applicability of equipment and pollutants has been determined, potential retrofit control technologies must be identified. In accordance with 40 CFR 51 Appendix Y and at the recommendation of the NMED[1], this is primarily achieved by utilizing the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) data. In order to determine the most relevant and current retrofit controls available, the RBLC is queried for the previous ten years. Summaries of the result of this search are provided and discussed under Section 2 of this report. Harvest engineers then reviewed the list of available retrofit technologies and performed a technical feasibility assessment for each control option. The four-factor analysis is then conducted for those controls that are technically feasible.

[1] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

NO_X is the only pollutant subject to evaluation in this four-factor analysis for the eight turbines located at San Juan. Unit 1 through 3 and Unit Rotating Spare are Rolls-Royce Avon model 1535 natural gas-fired, simple cycle turbines. Units 4 through 7 are Solar model Centaur T4501 natural gas-fired, simple cycle turbines.

Unit 1 through 3 and Unit Rotating Spare are rated at 15,000 horsepower and were manufactured in 1985 or 1986. Units 4 through 7 are rated at 3,735 horsepower and were manufactured in 1986.

Per NMED Guidance received on 9/23/2019, the four-factor analysis is to be completed only for units which are a steady state source of emissions. Unit Rotating Spare is a backup unit, which only operates when Unit 1, 2 or 3 are down for maintenance or repair. The unit is kept in a warehouse and is not a source of emissions unless it is commissioned to replace one of the primary turbines. Due to the intermittent nature of emissions and non-steady state operation, no further assessment of Unit Rotating Spare will be included in this four-factor analysis.

2.1. COMBUSTION TURBINES

2.1.1. Combustion Turbine Background

A gas turbine is an internal combustion engine that operates with a rotary, rather than reciprocating, motion and is composed of three primary components: a compressor, a combustor, and a power turbine. The compressor draws in ambient air and compresses it up to 30 times the ambient pressure, then directs it into the combustor where fuel is introduced, ignited, and burned. Exhaust gas from the combustor is then diluted with additional air and sent to the power turbine at temperatures up to 2600 °F. The hot exhaust gas expands in the power turbine section, generating energy in the form of shaft horsepower.[2]

The treatment of the exhaust gases exiting the turbine dictate the cycle designation of these units. The heat content can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).[3] The units at San Juan are simple cycle turbines.

NO_X is formed via three fundamentally different mechanisms. The principle NO_X formation mechanism, thermal NO_X, arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion. Most thermal NO_X forms in the highest temperature regions of the combustion chamber. The second NO_X formation mechanism, fuel NO_X, arises from the evolution and reaction of fuel bound nitrogen compounds with oxygen. The final NO_X formation mechanism, prompt NO_X, arises from early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The significance of prompt NO_X is negligible in comparison to thermal and fuel NO_X. Fuel NO_X will also be negligible for San Juan's turbines assessed here, as these combustion turbines fire natural gas, which contains a negligible amount of nitrogen compounds. Therefore, this analysis will focus on thermal NO_X.

[2] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"
[3] Ibid.

The PTE from each turbine is reported in the facility's New Source Review (0613-M10R2) and Title V (P124-R3) permits, as well as summarized in Table 1 of this report.

2.1.2. Potential NO_X Controls for a Combustion Turbines

There are three general methods of controlling NO_X emission from gas turbines: (1) wet controls, which use steam or water injection to reduce combustion temperatures and NO_X formation; (2) dry controls that use advanced combustor design to suppress NO_X formation; and (3) post-combustion, catalytic controls to selectively reduce NO_X.[4]

The retrofit control equipment that was identified for combustion turbines during a comprehensive review of the RBLC, available literature, and manufacturer's input is reported in Table 2. A more detailed table summarizing the RBLC review is provided in Appendix A. A detailed discussion, including a description, the technical feasibility, and the anticipated performance of each control is provided below.

Table 2. Potential Control Options for Combustion Turbines

Control Equipment	Technically Feasible for Rolls-Royce (Units 1 through 3)?	Technically Feasible for Solar (Units 4 through 7)?	NO_X Control Efficiency
Good Combustion Practices	Yes	Yes	Base Case
Improved Combustion Technology	No	Yes	65% - 75%
Water/Steam Injection	No	No	N/A
Selective Catalytic Reduction	No	Yes	65% - 75%

2.1.2.1. Good Combustion Practices

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from combustion turbines; therefore, it has been determined that this method of NO_X control is feasible for the units at San Juan. However, these practices have been developed and are currently in use at San Juan, as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices is included in this report.

2.1.2.2. Improved Combustion Technology

The improved combustion technology control option, commonly referred to as Dry Low Emissions (DLE) control, seeks to reduce the combustion temperature and residence time of fuel in the combustor (thereby decreasing NO_X

[4] Ibid.

formation) by increasing the air-to-fuel ratio in the combustion chamber. There are several levels of improvements that can be made to the combustion chamber, which achieve this NO_X control at varying levels.

2.1.2.2.1 Rolls-Royce Avon Units

The Rolls-Royce Avon energy gas turbine and compressor business is currently owned and operated by Siemens. Based on communication with Siemens, there are no DLN control options for the model of turbines located at San Juan. The units were designed and manufactured prior to the enhanced environmental awareness present today; and therefore, were not designed to suitably implement emissions control measures. The unavailability is also likely due to lack of market demand to improve the control efficiency of these older units.

Per conversations with a Siemens representative, a small number of these turbine models were retrofit with DLN emissions controls as a pilot study, but the units did not function properly after installation of the control. Therefore, testing of DLN controls for these turbines was halted and the control eliminated as a viable option. DLN controls were not offered to the market to control emissions from these units.

Per 40 CFR Part 51, Appendix Y, "a technology is considered 'available' if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term."[5] Further, source owners are not expected to "construct a process or control device that has not already been demonstrated in practice."[6]

DLN controls are not currently offered on the market for these turbines; therefore, this control is not considered to be available as described above. Additionally, there is historical precedent which indicates that installation of these controls would result in decreased functionality of the units. For these reasons, it has been determined that this control technology is infeasible for the Rolls-Royce turbines located at San Juan.

2.1.2.2.2 Solar Units

The improved combustion technology available for the units at San Juan is produced by the manufacturer of the units, Solar, and is called SoLoNO$_X$. Based on communication with Solar, SoLoNO$_X$ is available for the T4501 Solar turbines located onsite; however, each of the units would need to be uprated to model Centaur T4701 in order to support the technology. The uprate is necessary because installation of SoLoNO$_X$ requires the turbine combustors to be capable of handling significantly higher temperatures. Uprating the units involves replacing the combustor section of the turbine with a much larger and more robust combustor. Solar can guarantee an output NO_X concentration of 25 parts per million (ppm) for uprated units with SoLoNO$_X$ installed, resulting in a NO_X emissions reduction of approximately 65 - 75%, based on the 2016 hourly emission rate and turbine stack parameters of each unit.

Improved combustion technology was identified in this review of RBLC as a potential control of NO_X emissions from natural gas-fired combustion turbines, and AP-42 Section 3.1 also lists this as an available control technique for gas turbines.[7] Therefore, it has been determined that this control technology is technically feasible for the Solar turbines located at San Juan.

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[5] 40 CFR 51, Appendix Y, Section IV.D.2
[6] 40 CFR 51, Appendix Y, Section IV.D.1
[7] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"

2.1.2.3. Water/Steam Injection

Water or steam injection is a control technology for gas turbines that has been demonstrated to effectively suppress NO_X emissions. Injection of steam and water has the effect of increasing the thermal mass by dilution and thereby reducing the peak temperature in the flame zone. Additionally, the latent heat of vaporization from the flame zone is absorbed when water injection is utilized, further reducing the combustion temperature. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.[8]

2.1.2.3.1 Rolls-Royce Avon Units

Water/steam injection was identified in this review of RBLC as a potential control of NO_X emissions from natural gas-fired combustion turbines, and AP-42 Section 3.1 also lists water/steam injection as an available control technique for gas turbines.[9] However, communication with Siemens has indicated that water/steam injection is not currently offered for the model of turbines located at San Juan, and is therefore not considered available. Additionally, as this technology has not been installed on this model of turbine, there is no historical data to support that installation of these controls would result in significant reductions of NO_X emissions. For these reasons, it has been determined that this control technology is infeasible for the Rolls-Royce turbines located at San Juan.

2.1.2.3.2 Solar Units

Steam injection is not discussed as an option for these units because Solar does not manufacture turbines with steam injection technology. The capability of these units to be retrofit for water injection is dependent on the number of shafts employed in the unit, per communication with Solar. The shaft is the piece of equipment in the unit that is turned by the turbine to generate work. Solar has indicated that turbine units with one shaft are mechanically capable of installing water injection, while two-shaft units are not. The Solar Model T4501 turbines located at San Juan are one-shaft units and are, therefore, capable of being retrofit with water injection controls.

Despite the Solar T4501 being mechanically capable of supporting water injection, Solar has stated that they do not offer water injection retrofits for any of the Centaur 40 conventional combustion line of turbines. This is primarily due to the design of the combustor housing of the conventional Centaur 40. The injectors on this style of combustor intersect directly into the combustor without using direct air flow for the direction of fuel. The style of injector needed to implement water injection technology is referred to by Solar as a Dual Lined Injector. This type of injector introduces fuel laterally into the front of a combustor and utilizes a controlled flow to disperse fuel.

Solar considers the control technique to be antiquated technology in comparison to the other control methods they have available, such as $SoLoNO_X$. Solar has retired this control option and does not recommend water injection be installed to control emissions from their turbine units. They have stated that if there were direct modifications made to the turbine engine or it's supporting hardware, it could affect the unit's warranty with Solar.

Furthermore, per conversations with Solar, approximately 5 gallons per minute (gpm) of de-ionized or de-mineralized water will be needed to properly implement this control. For a continuously operating turbine, this represents a total water usage of approximately 2.6 million gallons per year, per unit, without taking into account leaks and evaporative losses that would occur during transport. The facility is located in San Juan County, in the northwestern part of the state. The National Drought Mitigation Center currently classifies this region as

[8] Ibid.
[9] Ibid.

experiencing severe drought conditions.[10] The New Mexico Office of the State Engineer projects that the water demand in the San Juan region will exceed the drought-adjusted available water supply before 2030.[11] The implementation of this control may pose an unsustainable burden on this region's watershed.

Based on the communication with the turbine manufacturer detailed above, as well as the lack of available water in the region, it has been determined that water injection control is technically infeasible for the Solar turbines located at San Juan.

2.1.2.4. Selective Catalytic Reduction Systems

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[12] The chemical reactions for this process are shown in the equations below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

An SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and an electronic control system. The electronic controls regulate the quantity of reagent injected as a function of turbine load, speed, and temperature, so NO_X emissions reductions can be achieved. The lifespan of the catalyst is primarily determined by poisoning of active sites by flue gas constituent; thermal sintering, or compacting, of active sites due to high temperatures in the reactor; fouling caused by ammonia-sulfur salts and particulate matter in the gas; and erosion due to high gas velocities.[13]

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as ammonia slip. Unreacted ammonia in the exhaust can form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams can blind the catalyst and may necessitate the application of a soot blower.[14]

For an SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 and 850 °F), dependent on the material of the catalyst. Exhaust gas temperatures greater than the upper limit will cause the NO_X and ammonia to pass through the catalyst unreacted.[15]

2.1.2.4.1 Rolls-Royce Avon Units

As provided by site engineers, the exhaust temperature of the Rolls-Royce Avon turbines is 1,250 °F, and is therefore outside of the temperature range necessary to support SCR control. It is unlikely that SCR control would function effectively on the Rolls-Royce turbines due to the high exhaust temperature of these units. Additionally,

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[10] Brian Fuchs, National Drought Mitigation Center, "United States Drought Monitor – New Mexico", https://droughtmonitor.unl.edu/CurrentMap/StateDroughtMonitor.aspx?NM
[11] State of New Mexico Interstate Stream Commission, Office of the State Engineer, "San Juan Basin Regional Water Plan 2016", Figure ES-3. Available Supply and Projected Demand.
[12] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
[13] Ibid.
[14] Ibid.
[15] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"

there are potential site-specific space limitations that prevent the installation of the necessary equipment for this control method (i.e., SCR module and reagent storage systems).

Furthermore, Harvest does not anticipate that the current electricity availability at San Juan will be sufficient to support the substantial energy burden associated with SCR control. Installation of this control will require the facility to expand its current power generation.

Communication with Siemens has indicated that SCR controls are available for the turbine model assessed here. However, it is not anticipated that the exhaust temperature, space, and energy limitations can be overcome. Therefore, it has been determined that this control technology is infeasible for the Rolls-Royce turbines located at San Juan.

2.1.2.4.2 Solar Units

The exhaust temperature of the turbines assessed here is within the necessary operating range for SCR control, at approximately 827 °F. However, the site-specific space and energy limitations discussed above apply to these units as well.

Communication with Solar has indicated that SCR controls are available for the Solar turbines assessed here. Therefore, assuming that the space limitations can be overcome, SCR is considered a technically feasible control option for the turbines located at San Juan. Solar has estimated that installation of SCR control on these units will result in an output NO_X concentration of 25 parts per million (ppm), resulting in a NO_X emissions reduction of approximately 65 - 75%, based on the 2016 hourly emission rate and turbine stack parameters of each unit.

Harvest has evaluated the costs of implementing the technologically feasible control technologies as thoroughly as possible in the time provided to complete this assessment. These cost estimates are calculated according to the methods and recommendations in the EPA Air Pollution Control Cost Manual.[16] Cost effectiveness considerations for each unit and control technology are discussed below.

These cost estimates have been developed based on the actual emissions from each unit assessed here, using the 2016 Emission Inventory submittal for San Juan. The full cost estimation for each unit, including the EPA Air Pollution Control Cost Spreadsheet, is included in Appendix B of this report.

3.1. SOLAR TURBINES

Cost effectiveness for each technically feasible Solar combustion turbine control option are summarized Table 3.

Table 3. Cost Analysis Summary of Technically Feasible Control Options for Solar Turbines

Control Equipment	Unit	Capital Cost ($)	Total Annual Cost ($)*	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Improved Combustion Technology (SoLoNO$_X$)	4	563,300	69,637	35.7	1,952
	5	563,300	69,637	28.9	2,412
	6	563,300	69,637	36.8	1,894
	7	563,300	69,637	46.4	1,500
Selective Catalytic Reduction **(SCR)**	4	4,000,000	457,586	35.7	12,824
	5	4,000,000	456,964	28.9	15,825
	6	4,000,000	457,827	36.8	12,455
	7	4,000,000	458,936	46.4	9,883

*Total Annual Cost includes the annualized capital cost, as well as the direct and indirect annual operating costs.

3.1.1. Improved Combustion Technology

Harvest has received an estimated direct capital cost for the equipment and vendor labor associated with implementing SoLoNO$_X$ on the turbines located at San Juan from Solar. Solar has also provided an estimated annual cost necessary to operate and maintain the units post-retrofit.

This cost estimate assumes that SoLoNO$_X$ will reduce NO$_X$ emissions to an outlet concentration of 25 ppm, based on manufacturer's estimations.

[16] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

3.1.2. SCR

Harvest has received an estimated direct capital cost for the equipment and vendor labor associated with implementing an SCR system on the model of turbines located at San Juan from the manufacturer.

The EPA Air Pollution Control Cost Spreadsheet for SCR is used to estimate the direct annual costs (maintenance, operating labor, reagent cost, electricity cost, and catalyst cost) and indirect annual costs associated with Harvest's internal labor, overhead and capital recovery for the project.

This cost estimate assumes that the SCR will reduce NO_X emissions to an outlet concentration of 25 ppm, based on manufacturer's estimations.

The second factor in this analysis is the time necessary for compliance. Consideration of this factor involves estimating the time required for a source to implement a potential control measure. This information is provided here in order to advise the NMED of Harvest's projection of a reasonable compliance timeline based on the equipment and site-specific considerations that could affect the time necessary to comply.

4.1. SOLAR TURBINES

4.1.1. Improved Combustion Technology

Harvest estimates that approximately 2-3 years will be needed to implement the improved combustion technology control equipment (SoLoNO$_X$). Factors that have been considered for this anticipated timeline include budgeting, design, uprating the combustors, procuring the equipment, and installing the control.

4.1.2. SCR

Harvest estimates that approximately 2-3 years will be needed to budget, plan, order, deliver and install the SCR control equipment.

This section addresses the potential energy and non-air environmental impacts that installation of the technically feasible control options poses on a source. The consideration of energy impacts involves assessing the impact of a control measure on the energy that is consumed by the source. Non-air environmental impacts are assessed based on the effect of the control on non-air environmental media. Some examples of non-air environmental impacts include water resource depletion, solid waste generation, increased noise and odor pollution, and increased land usage.

5.1. SOLAR TURBINES

5.1.1. Improved Combustion Technology

It is not anticipated that installation of the improved combustion technology (SoLoNO$_X$) on the Solar turbines at San Juan will have any significant energy or non-air environmental impacts.

5.1.2. SCR

The implementation of SCR on the turbines at San Juan would result in several energy and non-air environmental impacts. The primary impact of this control would be a significant increase in energy consumption, which would be necessary to power the units. The estimated energy consumption for each unit is summarized in Table 4, and is based on the EPA Air Pollution Control Cost Manual.[17] The calculation for these values is included in Appendix C of this report. Harvest does not anticipate that the current electricity availability at San Juan will be sufficient to support this increased energy burden. Installation of this control will require the facility to expand its current power generation. The costs of this associated power expansion are not accounted for in the SCR cost estimates included in Table 3.

Table 4. Turbine SCR Energy Consumption Analysis Summary

Unit	Annual Energy Consumption (MWh/yr)
4	95.8
5	100.1
6	99.2
7	97.3
Total	392.4

In addition to the increased energy burden, there are several non-air environmental impacts associated with the handling and storage of the reagent used in the SCR system, typically ammonia or urea. Ammonia is a Toxic Air Pollutant (TAP) regulated under 20.2.72.502 NMAC with an occupational exposure limit (OEL) of 18 mg/m^3. In both soil and water, urea is hydrolyzed quickly to ammonia and carbon dioxide by urease, an extracellular enzyme that originates from microorganisms and plant roots.[18] Short-term inhalation exposure to high levels of ammonia

[17] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

[18] U.S. EPA, EPA/635/R-10/005F, "Toxilogical Report of Urea", July 2011

in humans can cause irritation and serious burns in the mouth, lungs, and eyes. Chronic exposure to airborne ammonia can increase the risk of respiratory irritation, cough, wheezing, tightness in the chest, and impaired lung function in humans. Animal studies also suggest that exposure to high levels of ammonia in air may adversely affect other organs, such as the liver, kidney, and spleen.[19]

Unavoidable releases of ammonia could have significant and irreversible impacts on the living and physical environment affected. Storage and handling of urea or ammonia onsite would result in an increased risk to the health and safety of facility operators. San Juan is a natural gas processing plant, which already maintains a high level of health and safety risk. Harvest considers any increase to this risk unacceptable.

[19] U.S. EPA, EPA/635/R-16/163Fc, "Toxicological Review of Ammonia Noncancer Inhalation: Executive Summary", September 2016

The anticipated remaining useful life of each source is addressed here for the NMED's consideration. The assessment of this factor involves estimating how long the sources analyzed will remain in operation and the lifetime of potential control measures, accounting for equipment and site-specific limitations.

40 CFR Part 51, Appendix Y includes guidance on the characterization of this factor, stating that the remaining useful life of a source will typically be longer than the useful life of the emission control system. Therefore, it is appropriate to annualize compliance costs based on the useful life of the control equipment, rather than the life of the source.[20]

Based on their current age and operating efficiency, it is estimated that the remaining useful life of the Solar turbines will be longer than the control units. The turbines have operated for more than 30 years without any significant deterioration in operating efficiency; therefore, this analysis of the remaining useful life of the equipment will be based on the anticipated useful life of the control device considered.

6.1. SOLAR TURBINES

6.1.1. Improved Combustion Technology

It is anticipated that the estimated useful life of the improved combustion technology, SoLoNO$_X$, will be similar to the useful life of an SCR system. The useful life is estimated to be 20 years, based on default values from the EPA Air Pollution Control Cost Manual.[21]

6.1.2. SCR

The estimated useful life of the SCR equipment is 20 years, based on default values from the EPA Air Pollution Control Cost Manual.[22]

[20] 40 CFR 51, Appendix Y, Section II.B.4.f
[21] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual
[22] Ibid.

Based on a comprehensive review of the RBLC, available literature, and manufacturer's input of the available control technologies for the natural-gas fired turbines located at San Juan, Harvest has determined that there are no technically feasible control options for the Rolls-Royce turbines that are not currently implemented at the facility due to the age of the units.

At this time, Harvest would like to advise the NMED of additional concerns regarding the retrofit of the Rolls-Royce turbines. The manufacturer of these turbines, Siemens, is based out of Switzerland. Harvest is required to ship the turbines overseas for any necessary retrofits, repairs, or advanced maintenance requirements. This requires the turbine to be decommissioned and shipped via rail or truck across the country to an eastern port. From there, the turbine must be shipped via cargo ship to a port in Europe where it is then transferred via truck or rail again to Siemens for the applicable repairs/retrofits. Altering these turbines will undoubtedly increase operational complexity and will necessitate additional support from Siemens, contributing to severe cost implications.

Harvest has further determined that SoLoNO$_X$ and SCR are the only technically feasible control options for the Solar turbines. The cost of compliance to install the controls on each of these units has been estimated based on manufacturer's input, as well as the EPA Air Pollution Control Cost Manual.[23] The estimated cost effectiveness and NO$_X$ emission reduction for each unit are summarized in Table 5.

Table 5. Cost Effectiveness and NO$_X$ Reduction for Control of the Solar Turbines at San Juan

Control Equipment	Unit	NO$_X$ Reduction (tpy)	Cost Effectiveness ($/ton)
Improved Combustion Technology (SoLoNO$_X$)	4	35.7	1,952
	5	28.9	2,412
	6	36.8	1,894
	7	46.4	1,500
Selective Catalytic Reduction	4	35.7	12,824
	5	28.9	15,825
	6	36.8	12,455
	7	46.4	9,883

It is projected that the useful life of these units will be 20 years, based on the life expectancy of the SoLoNO$_X$ and SCR controls. The primary energy and non-air impacts from the SCR control method is increased energy consumption and health and safety risks associated with ammonia usage. Harvest estimates an achievable compliance timeline to implement either the SoLoNO$_X$ or SCR controls is 2-3 years.

[23] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

Furthermore, Harvest would like to advise the NMED of their judgement that the San Juan facility's potential contribution to regional haze at the Mesa Verde National Park Class I area is such that it does not justify their facility being selected for this assessment. There are hundreds of sources, both major and minor, located closer to the Class I area whose contribution has not been considered. Harvest would argue that only assessing high emitting sources at a limited number of facilities will not effectively address the visibility impairment problem, as required by the State under the RHR.

8. SUPPORTING DOCUMENTATION

Appendix A – RBLC Tables
Appendix B – Cost Analysis Calculations
Appendix C – SCR Energy Consumption Calculation

APPENDIX A - RBLC TABLES

RBLC Analysis for Natural Gas Fired Turbines – NO_X Control

	Control Technology	Good Combustion Technique	Improved Combustion Technology (Low-NO_X Combustors, Ultra-Low NO_X Combustors and other improved combustion technology)[a]	Water/Steam Injection[b]	Selective Catalytic Reduction (SCR)[c]
IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	NO_x emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. Primary combustion occurs at lower temperatures under oxygen-deficient conditions. By following EPA's "Good Combustion Practices" guidance document, good combustion practices can be maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices the unit will operate as intended with the optimal NO_x emissions.	Low-NO_x burners employ multi-staged combustion to inhibit the formation of NO_X. Primary combustion occurs at lower temperatures under oxygen-deficient conditions; secondary combustion occurs in the presence of excess air. This category includes Improved Combustion Technology Lean Head End Liners for the GE turbines assessed here.	Injected water/steam acts as a heat sink, lowering combustion zone peak temperatures, resulting in a decrease in thermal NO_X.	A nitrogen-based reagent (e.g., ammonia, urea) is injected into the exhaust stream downstream of the combustion unit. The reagent reacts selectively with NO_X to produce molecular N_2 and water in a reactor vessel containing a metallic or ceramic catalyst.
	Other Considerations	N/A	N/A	Results in a small efficiency penalty but an increase in power output. May increase CO and VOC emissions. Not available in certain models.	Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as "ammonia slip." Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.
	RBLC Database Information	Included in RBLC for control of NO_X emissions from combustion turbines.	Included in RBLC for the control of NO_X emissions from combustion turbines.	Not included in RBLC for the control of NO_X emissions from combustion turbines; identified as a control option based on AP-42 Section 3.1.	Included in RBLC for the control of NO_X emissions from combustion turbines.
ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	Feasibility Discussion	Technically feasible.	Solar Units - Technically feasible Rolls-Royce Units - Technically infeasible. This option is not available for the Rolls-Royce turbine model.	Technically infeasible. This option is not available for the turbine models assessed.	Solar Units - Technically feasible Rolls-Royce Units - Technically infeasible. This option is not available for the Rolls-Royce turbine model.
RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	Base Case	65 - 75%		65 - 75%

a. California EPA, Air Resources Board, "Section 311 - Non-Selective Catalytic Reduction and Other NO_X Controls," http://www.arb.ca.gov/cap/manuals/cntrldev/sncr_etc/311nscr.htm
b. U.S. EPA, AP-42 Section 3.1, "Stationary Gas Turbines"
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

Turbine RBLC Results

Completed RBLC Search on 9/19/2019 for a ten year period of 1/1/2019 to 09/19/2019

RBLCID	FACILITY NAME	EPA REGION	PERMIT NUM	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	COST EFFECTIVENESS	INCREMENTAL COST EFFECTIVENESS	Cost Verified	DOLLAR YEAR USED IN COST ESTIMATES
AK-0083	XENAI NITROGEN OPERATIONS	10	AQ0083CPT06	Five (5) Natural Gas Fired Combustion Turbines	16.11	Natural Gas	37.6	MMBTU/H	Five (5) Natural Gas-Fired Solar Combustion Turbines rated at 37.6 MMBtu/hr each. Installed in 1976.	Nitrogen Oxides (NOx)	A	Selective Catalytic Reduction	0			0	0	N	
CA-1215	QUALCOMM INC.	9	2012- APP-002100	Cogeneration gas turbine	16.11	natural gas	4.37	MW	Manufacturer: Solar Turbines- Model: Mercury 50-6400R	Nitrogen Oxides (NOx)	A	SoLoNOx burner (Ultra lean Premix)	0			0	0	N	
LA-0331	CALCASIEU PASS LNG PROJECT	6	PSD-LA-805	Aeroderivative Simple Cycle Combustion Turbine	16.11	Natural Gas	263	MM BTU/h		Nitrogen Oxides (NOx)	B	Selective Catalytic Reduction (SCR), exclusive combustion of fuel gas, and good combustion practices.	0			0	0	N	
MI-0410	THETFORD GENERATING STATION	5	191-12	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	16.11	natural gas	171	MMBTU/H	Two natural gas fired simple cycle combustion turbines each with an electrical generator (nominal 13MW each; 171 MMBtu/hr heat input rating each). Each turbine is limited to 343 MMscf of natural gas per 12-month rolling time period as determined at the end of each calendar month. Both turbines combined are limited to 5.15 MMscf of natural gas each calendar day.	Nitrogen Oxides (NOx)	P	Dry low-NOx combustors	0			0	0	N	
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	5	185-15	FG-TURBINES	16.11	Natural gas	10504	HP	Five (5) simple cycle natural gas-fired combustion turbines (CTs) to drive compressors that will be used to transport natural gas through pipelines. The turbines are identified as EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, and EUTURBINE5 within the flexible group FGTURBINES. There shall be no more than a combined total of 5 events (startup or shutdown) per clock hour. The total number of startup events for all units combined shall not exceed 500 events per 12-month rolling time period. The total number of shutdown events for all units combined shall not exceed 500 events per 12-month rolling time period. The maximum nominal rating of each turbine shall not exceed 10,504 HP (ISO).	Nitrogen Oxides (NOx)	A	Dry ultra-low NOx burners	0			0	0	N	
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	5	185-15A	FGTURNBINES (5 Simple Cycle CTs: EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5)	16.11	Natural gas	10504	HP	Five simple cycle natural gas-fired combustion turbines (CTs) to drive compressors that will be used to transport natural gas through pipelines (EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5 in FGTURBINES). There shall be no more than a combined total of 5 events (startup or shutdown) per clock hour. The total number of startup events for all units combined shall not exceed 500 events per 12-month rolling time period. The total number of shutdown events for all units combined shall not exceed 500 events per 12-month rolling time period. The maximum nominal rating of each turbine shall not exceed 10,504 HP (ISO).	Nitrogen Oxides (NOx)	A	Dry ultra-low NOx burners.	0			0	0	N	
NV-0050	MGM MIRAGE	9	825	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	16.11	NATURAL GAS	4.6	MMBTU/H	THE TWO UNITS ARE IDENTICAL SOLAR MERCURY COMBUSTION GAS TURBINES FOR ELECTRIC POWER GENERATION. EACH UNIT IS RATED AT 4.6 MMBTU/HR, AND IS ALLOWED TO OPERATE 24 HOURS/DAY AND 8,760 HOURS/YEAR.	Nitrogen Oxides (NOx)	P	LEAN PRE-MIX TECHNOLOGY AND LIMITING THE FUEL TO NATURAL GAS ONLY	0.178	LB/MMBTU		0	0	N	
OK-0148	BUFFALO CREEK PROCESSING PLANT	6	2012-1026-C-PSD	Small Combustion Turbines (<25MW)	16.11	Natural Gas	10179	Horsepower	Solar Taurus 70-10802S times 2	Nitrogen Oxides (NOx)	P	Dry-Low NOx Combustion	0			0	0	N	
OK-0153	ROSE VALLEY PLANT	6	2012-1393-C-PSD	TURBINES 9,443 HP SIEMENS SGT-200-2S	16.11	NATURAL GAS	9443	HP	THERE ARE TO BE LIKE-KIND TURBINES.	Nitrogen Oxides (NOx)	P	DRY LOW-NOx COMBUSTION.	0			0	0	N	
*PA-0314	BEECH HOLLOW	3	63-029220	COMBUSTION TURBINE without DUCT BURNERS UNIT	16.11	Natural Gas	2413	$MMBtu/hr$	CEMS for NOx, CO	Nitrogen Oxides (NOx)	A	SCR	0			0	0	N	
TX-0642	SINTON COMPRESSOR STATION	6	PSDTX1304	Compression Turbine	16.11	natural gas	20000	hp	Two (2) 20,000 horsepower Solar Titan 130S turbines in natural gas pipeline compression service	Nitrogen Oxides (NOx)	P	Solar's SoLoNOx dry emission control technology	0			0	0	N	
TX-0685	GUADALUPE GENERATING STATION	6	106011 PSDTX1110	(2) simple cycle turbines	16.11	natural gas	190	MW	Four models are approved: GE7FA.03, GE7FA.04, GE7FA.05, or Siemens SW 5000FS. 383 MW to 454 MW total plant capacity.	Nitrogen Oxides (NOx)	B	DLN burners, limited operation	0			0	0	N	
*WI-0283	AFE, INC. â€"LCM PLANT	5	17-J0W-207	P90 â€" Natural Gas-Fired Emergency Generator	16.11	Natural Gas	9.51	mmBTU/hr	750 kW or 1,114 brake horsepower	Nitrogen Oxides (NOx)	P	Good Combustion Practices and the Use of Turbocharger and Aftercooler	0			0	0	N	
WY-0067	ECHO SPRINGS GAS PLANT	8	MD-7837	TURBINES S35-S36	16.11	NATURAL GAS	12555	HP	TWO (2) 12,555 HP SOLAR MARS 100-15000S TURBINES	Nitrogen Oxides (NOx)	N	SOLONOX	0			0	0	N	
WY-0067	ECHO SPRINGS GAS PLANT	8	MD-7837	TURBINE S34	16.11	NATURAL GAS	9856	HP	SOLAR CENTAUR 40-T4700S	Nitrogen Oxides (NOx)	N	SOLONOX	0			0	0	N	

APPENDIX B – COST ANALYSIS CALCULATIONS

Harvest Four Corners, LLC

San Juan Gas Plant

Turbine Cost Analysis Interest Rate: 5.50%

All Units Period (yrs): 20

Solar Centaur T4501					
Control Equipment	**Unit**	**Capital Cost ($)**	**Total Annual Cost* ($)**	**Emission Reduction (tpy)**	**Cost Effectiveness ($/ton)**
Improved Combustion ($SoLoNO_X$)	4	563,300	69,637	35.7	1,952
	5	563,300	69,637	28.9	2,412
	6	563,300	69,637	36.8	1,894
	7	563,300	69,637	46.4	1,500
Selective Catalytic Reduction (SCR)	4	4,000,000	457,586	35.7	12,824
	5	4,000,000	456,964	28.9	15,825
	6	4,000,000	457,827	36.8	12,455
	7	4,000,000	458,936	46.4	9,883

* Total Annual Cost includes the annualized capital cost as well as the direct and indirect annual operating costs.

Harvest Four Corners, LLC

San Juan Gas Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 4	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4501		

Base (85.08 ppm)			
NO_X ppm:	85.08	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:	50.53	tpy	<-- From 2016 EI calculations

SoLoNO_X (25 ppm)			
NO_X guarantee:	25	ppm	<-- from Solar
NO_X tpy:	14.85	tpy	
Total Cap Investment	$ 563,300		<-- from Solar
Annualized TCI:	$ 47,137		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 22,500		<-- from Solar
Total Annual Costs:	$ 69,637		
Emissions Reduction:	35.68	tpy	
Cost Effectiveness:	**$ 1,951.57**	**$/ton**	

SCR (25 ppm)			
NO_X guarantee:	25	ppm	<-- Estimated based on control efficiency
NO_X tpy:	14.85	tpy	
Total Cap Investment	$ 4,000,000		<-- Vendor estimate
Annualized TCI:	$ 334,717		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 122,869		<-- from Cost Control Spreadsheet
Total Annual Costs:	$ 457,586		
Emissions Reduction:	35.68	tpy	
Cost Effectiveness:	**$ 12,823.90**	**$/ton**	
Incremental Cost:	$ 10,872.32	$/ton	

Unit 4: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine?

Is the SCR for a new turbine or retrofit of an existing turbine?

What type of fuel does the unit burn?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.: 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 23.66 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,000 Btu/scf

What is the estimated actual annual fuel consumption? 186,400,000 scf/Year

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 5600 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Select for Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,943
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.83	6,656

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired turbines, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR}): 365 days

Number of days the turbine operates (t_{plant}): 365 days

Inlet NO_x Emissions (NOx_{in}) to SCR: 0.54 lb/MMBtu

Outlet NO_x Emissions (NOx_{out}) from SCR: 0.159 lb/MMBtu

Stoichiometric Ratio Factor (SRF): 1.050

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst ($H_{catalyst}$): 24,000 hours

Estimated SCR equipment life: 20 Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored}): 29 percent*

Density of reagent as stored (ρ_{stored}): 56 lb/cubic feet*

Number of days reagent is stored ($t_{storage}$): 14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Select the reagent used

Number of SCR reactor chambers (n_{scr}): 1

Number of catalyst layers (R_{layer}): 3

Number of empty catalyst layers (R_{empty}): 1

Ammonia Slip (Slip) provided by vendor: 2 ppm

Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known): UNK Cubic feet

Flue gas flow rate ($Q_{Flue gas}$) (Enter "UNK" if value is not known): UNK acfm

Gas temperature at the SCR inlet (T): 650 °F

Base case fuel gas volumetric flow rate factor (Q_{fuel}): 484 ft^3/min-MMBtu/hour

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SCR:

Desired dollar-year: 2018

CEPCI for 2018: 603.1 Enter the CEPCI value for 2018 | 603.1 | 2018 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i): 5.5 Percent*

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/ .)

Reagent ($Cost_{reag}$): 0.293 $/gallon for 29% ammonia*

* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.

Electricity ($Cost_{elect}$): 0.0676 $/kWh

* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.

Catalyst cost ($CC_{replace}$): 227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

Operator Labor Rate: 60.00 $/hour (including benefits)*

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

Operator Hours/Day: 4.00 hours/day*

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) = 0.005

Administrative Charges Factor (ACF) = 0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

Unit 4: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	24	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	207,295,163	scf/Year	
Actual Annual fuel consumption (Mactual) =		186,400,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.899	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7877	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	9.06	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	35.68	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.88		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	10,960	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	120.19	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	psia	
Retrofit Factor (RF)	Retrofit to existing turbine	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyst}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	91.18	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	11	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	13	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	3.6	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	4	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	12	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	600	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	12.17	kW

Unit 4: Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	$4,000,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$120,001	in 2018 dollars
Indirect Annual Costs (IDAC) =	$337,668	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$457,669	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Operating Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$20,000	in 2018 dollars
Annual Operating Cost =	Operator Labor Rate x Hours/Day x t_{SCR} =	$87,600	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$3,743	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$6,479	in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$2,178	in 2018 dollars
Direct Annual Cost =		$120,001	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,868	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$334,800	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$337,668	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$457,669	per year in 2018 dollars
NOx Removed =	35.68	tons/year
Cost Effectiveness =	$12,826	per ton of NOx removed in 2018 dollars

Harvest Four Corners, LLC

San Juan Gas Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 5	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4501		

Base (71.29 ppm)				
NO_X ppm:		71.29	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:		44.47	tpy	<-- From 2016 EI calculations

SoLoNO$_X$ (25 ppm)				
NO_X guarantee:		25	ppm	<-- from Solar
NO_X tpy:		15.59	tpy	
Total Cap Investment	$	563,300		<-- from Solar
Annualized TCI:	$	47,137		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	22,500		<-- from Solar
Total Annual Costs:	$	69,637		
Emissions Reduction:		28.88	tpy	
Cost Effectiveness:	**$**	**2,411.59**	**$/ton**	

SCR (25 ppm)				
NO_X guarantee:		25	ppm	<-- Estimated based on control efficiency
NO_X tpy:		15.59	tpy	
Total Cap Investment	$	4,000,000		<-- Vendor estimate
Annualized TCI:	$	334,717		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	122,246		<-- from Cost Control Spreadsheet
Total Annual Costs:	$	456,964		
Emissions Reduction:		28.88	tpy	
Cost Effectiveness:	**$**	**15,825.12**	**$/ton**	
Incremental Cost:	$	13,413.53	$/ton	

Unit 5: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine?

Is the SCR for a new turbine or retrofit of an existing turbine?

What type of fuel does the unit burn?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.: 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 23.52 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,000 Btu/scf

What is the estimated actual annual fuel consumption? 194,600,000 scf/Year

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 5600 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Select for Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,943
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.83	6,656

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired turbines, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR}) 365 days

Number of days the turbine operates (t_{plant}) 365 days

Inlet NO_x Emissions (NOx_{in}) to SCR 0.46 lb/MMBtu

Outlet NO_x Emissions (NOx_{out}) from SCR 0.160 lb/MMBtu

Stoichiometric Ratio Factor (SRF) 1.050

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr}) 1

Number of catalyst layers (R_{layer}) 3

Number of empty catalyst layers (R_{empty}) 1

Ammonia Slip (Slip) provided by vendor 2 ppm

Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known) UNK Cubic feet

Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known) UNK acfm

Estimated operating life of the catalyst ($H_{catalyst}$) 24,000 hours

Estimated SCR equipment life 20 Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T) 650 °F

Base case fuel gas volumetric flow rate factor (Q_{fuel}) 484 ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored}) 29 percent*

Density of reagent as stored (ρ_{stored}) 56 lb/cubic feet*

Number of days reagent is stored ($t_{storage}$) 14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used

Enter the cost data for the proposed SCR:

Desired dollar-year 2018

CEPCI for 2018 603.1 Enter the CEPCI value for 2018 603.1 2018 CEPCI — CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i) 5.5 Percent* — * 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/ .)

Reagent ($Cost_{reag}$) 0.293 $/gallon for 29% ammonia* — * $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.

Electricity ($Cost_{elect}$) 0.0676 $/kWh — * $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.

Catalyst cost ($CC_{replace}$) 227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst — * $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

Operator Labor Rate 60.00 $/hour (including benefits)* — * $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

Operator Hours/Day 4.00 hours/day* — * 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) = 0.005

Administrative Charges Factor (ACF) = 0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

Unit 5: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	24	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	206,055,361	scf/Year	
Actual Annual fuel consumption (Mactual) =		194,600,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.944	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8273	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	64.9	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	6.98	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	28.88	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.81		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	10,894	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	131.10	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	psia	
Retrofit Factor (RF)	Retrofit to existing turbine	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyst}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	83.10	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	11	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	13	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	3.6	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	51	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	3	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	9	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	1	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	500	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	12.10	kW

Unit 5: Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	$4,000,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$119,378	in 2018 dollars
Indirect Annual Costs (IDAC) =	$337,668	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$457,046	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Operating Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$20,000	in 2018 dollars
Annual Operating Cost =	Operator Labor Rate x Hours/Day x t_{SCR} =	$87,600	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$3,029	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$6,764	in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$1,985	in 2018 dollars
Direct Annual Cost =		$119,378	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,868	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$334,800	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$337,668	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$457,046	per year in 2018 dollars
NOx Removed =	28.88	tons/year
Cost Effectiveness =	$15,828	per ton of NOx removed in 2018 dollars

Harvest Four Corners, LLC

San Juan Gas Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 6	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4501		

Base (82.57 ppm)

NO_X ppm:	82.57	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:	52.72	tpy	<-- From 2016 EI calculations

SoLoNO$_X$ (25 ppm)

NO_X guarantee:	25	ppm	<-- from Solar
NO_X tpy:	15.96	tpy	
Total Cap Investment	$ 563,300		<-- from Solar
Annualized TCI:	$ 47,137		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 22,500		<-- from Solar
Total Annual Costs:	$ 69,637		
Emissions Reduction:	36.76	tpy	
Cost Effectiveness:	**$ 1,894.45**	**$/ton**	

SCR (25 ppm)

NO_X guarantee:	25	ppm	<-- Estimated based on control efficiency
NO_X tpy:	15.96	tpy	
Total Cap Investment	$ 4,000,000		<-- Vendor estimate
Annualized TCI:	$ 334,717		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 123,110		<-- from Cost Control Spreadsheet
Total Annual Costs:	$ 457,827		
Emissions Reduction:	36.76	tpy	
Cost Effectiveness:	**$ 12,455.07**	**$/ton**	
Incremental Cost:	$ 10,560.63	$/ton	

Unit 6: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine?

Is the SCR for a new turbine or retrofit of an existing turbine?

What type of fuel does the unit burn?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.: 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 22.78 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,000 Btu/scf

What is the estimated actual annual fuel consumption? 192,900,000 scf/Year

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 5600 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Select or Enter Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,943
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.93	6,656

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired turbines, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the turbine operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.55 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.165 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
		Flue gas flow rate ($Q_{Flue gas}$) (Enter "UNK" if value is not known)	UNK acfm

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours		
Estimated SCR equipment life	20 Years*	Gas temperature at the SCR inlet (T)	650 °F
		Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour
Concentration of reagent as stored (C_{stored})	29 percent*		
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*		
Number of days reagent is stored ($t_{storage}$)	14 days		

* For industrial turbines, the typical equipment life is between 20 and 25 years.

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used

Enter the cost data for the proposed SCR:

Desired dollar-year	2018		
CEPCI for 2018	603.1 Enter the CEPCI value for 2018	603.1 2018 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5 Percent*		* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia*		* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676 $/kWh		* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*		* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*		* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

Unit 6: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	23	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	199,551,724	scf/Year	
Actual Annual fuel consumption (Mactual) =		192,900,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.967	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8468	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	69.7	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	8.68	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	36.76	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.87		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	10,550	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	121.13	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	psia	
Retrofit Factor (RF)	Retrofit to existing turbine	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyst}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	87.10	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	11	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	13	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	3.6	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	3	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	12	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	600	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	11.71	kW

Unit 6: Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	$4,000,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$120,242	in 2018 dollars
Indirect Annual Costs (IDAC) =	$337,668	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$457,910	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Operating Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$20,000	in 2018 dollars
Annual Operating Cost =	Operator Labor Rate x Hours/Day x t_{SCR} =	$87,600	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$3,856	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$6,705	in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$2,081	in 2018 dollars
Direct Annual Cost =		$120,242	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,868	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$334,800	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$337,668	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$457,910	per year in 2018 dollars
NOx Removed =	36.76	tons/year
Cost Effectiveness =	$12,457	per ton of NOx removed in 2018 dollars

Harvest Four Corners, LLC

San Juan Gas Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 7	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4501		

Base (102.54 ppm)			
NO_X ppm:	102.54	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:	61.41	tpy	<-- From 2016 EI calculations

SoLoNO$_X$ (25 ppm)			
NO_X guarantee:	25	ppm	<-- from Solar
NO_X tpy:	14.97	tpy	
Total Cap Investment	$ 563,300		<-- from Solar
Annualized TCI:	$ 47,137		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 22,500		<-- from Solar
Total Annual Costs:	$ 69,637		
Emissions Reduction:	46.44	tpy	
Cost Effectiveness:	**$ 1,499.58**	**$/ton**	

SCR (25 ppm)			
NO_X guarantee:	25	ppm	<-- Estimated based on control efficiency
NO_X tpy:	14.97	tpy	
Total Cap Investment	$ 4,000,000		<-- Vendor estimate
Annualized TCI:	$ 334,717		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 124,219		<-- from Cost Control Spreadsheet
Total Annual Costs:	$ 458,936		
Emissions Reduction:	46.44	tpy	
Cost Effectiveness:	**$ 9,882.87**	**$/ton**	
Incremental Cost:	$ 8,383.30	$/ton	

Unit 7: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine?

Is the SCR for a new turbine or retrofit of an existing turbine?

What type of fuel does the unit burn?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.: 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 23.03 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,000 Btu/scf

What is the estimated actual annual fuel consumption? 189,200,000 scf/Year

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 5600 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fuel Mix % Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,943
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.83	6,656

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired turbines, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the turbine operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOX_{in}) to SCR	0.65 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOX_{out}) from SCR	0.158 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		Flue gas flow rate ($Q_{Flue gas}$) (Enter "UNK" if value is not known)	UNK acfm
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours		
Estimated SCR equipment life	20 Years*	Gas temperature at the SCR inlet (T)	650 °F
* For industrial turbines, the typical equipment life is between 20 and 25 years.		Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour
Concentration of reagent as stored (C_{stored})	29 percent*		
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*		
Number of days reagent is stored ($t_{storage}$)	14 days		

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used

Enter the cost data for the proposed SCR:

Desired dollar-year	2018		
CEPCI for 2018	603.1 Enter the CEPCI value for 2018	603.1 2018 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5 Percent*		* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia*		* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676 $/kWh		* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*		* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*		* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

Unit 7: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	23	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	201,751,917	scf/Year	
Actual Annual fuel consumption (Mactual) =		189,200,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.938	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8215	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	75.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	11.31	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	46.44	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.95		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	10,667	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	110.64	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	psia	
Retrofit Factor (RF)	Retrofit to existing turbine	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyst}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	96.41	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	11	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	13	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	3.6	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	53	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	4	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	15	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	700	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	11.84	kW

Unit 7: Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	$4,000,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$121,351	in 2018 dollars
Indirect Annual Costs (IDAC) =	$337,668	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$459,019	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Operating Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$20,000	in 2018 dollars
Annual Operating Cost =	Operator Labor Rate x Hours/Day x t_{SCR} =	$87,600	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$4,872	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$6,577	in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$2,303	in 2018 dollars
Direct Annual Cost =		$121,351	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,868	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$334,800	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$337,668	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$459,019	per year in 2018 dollars
NOx Removed =	46.44	tons/year
Cost Effectiveness =	$9,885	per ton of NOx removed in 2018 dollars

APPENDIX C – ENERGY CONSUMPTION CALCULATION

SCR Energy Usage Summary

Turbine SCR Energy Consumption Analysis Summary

Unit	Annual Energy Consumption (MWh)
4	95.8
5	100.1
6	99.2
7	97.3
Total	392.4

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San Juan Gas Plant

SCR Energy Usage Calculation

Unit: 4

Equation:	Electricity Consumption, kW =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$		Source: EPA Cost Spreadsheet
Where:	A =	0.1 x QB		EPA Cost Spreadsheet for industrial turbines
	QB =	23.66	MMBTU/hr	Maximum Annual Heat Input Rate
	CoalF =	1.0		EPA Cost Spreadsheet value for Oil and Natural Gas
	Heat Rate Factor (HRF) =	NPHR / 10		
	Net Plant Heat Input Rate (NPHR) =	8.2	MMBtu/MW	Default EPA Cost spreadsheet value
Calculation:	HRF =	0.82		
	A =	2.366		
	Unit 4 2016 Operating hours =	7,877.00	hours	2016 EI Submittal
	Electricity Consumption =	12.2	kW	
	Annual Electricity Consumption =	95.8	MWh/yr	

Harvest Four Corners, LLC

San Juan Gas Plant

SCR Energy Usage Calculation

Unit: 5

Equation:	Electricity Consumption, kW =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$		Source: EPA Cost Spreadsheet
Where:	A =	0.1 x QB		EPA Cost Spreadsheet for industrial turbines
	QB =	23.52	MMBTU/hr	Maximum Annual Heat Input Rate
	CoalF =	1.0		EPA Cost Spreadsheet value for Oil and Natural Gas
	Heat Rate Factor (HRF) =	NPHR / 10		
	Net Plant Heat Input Rate (NPHR) =	8.2	MMBtu/MW	Default EPA Cost spreadsheet value
Calculation:	HRF =	0.82		
	A =	2.352		
	Unit 5 2016 Operating hours =	8,273.00	hours	2016 EI Submittal

Electricity Consumption =	12.1	kW
Annual Electricity Consumption =	100.1	MWh/yr

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San Juan Gas Plant

SCR Energy Usage Calculation

Unit: 6

Equation:	Electricity Consumption, kW =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$		Source: EPA Cost Spreadsheet
Where:	A =	0.1 x QB		EPA Cost Spreadsheet for industrial turbines
	QB =	22.78	MMBTU/hr	Maximum Annual Heat Input Rate
	CoalF =	1.0		EPA Cost Spreadsheet value for Oil and Natural Gas
	Heat Rate Factor (HRF) =	NPHR / 10		
	Net Plant Heat Input Rate (NPHR) =	8.2	MMBtu/MW	Default EPA Cost spreadsheet value
Calculation:	HRF =	0.82		
	A =	2.278		
	Unit 6 2016 Operating hours =	8,468.00	hours	2016 EI Submittal
	Electricity Consumption =	11.7	kW	
	Annual Electricity Consumption =	99.2	MWh/yr	

Harvest Four Corners, LLC

San Juan Gas Plant

SCR Energy Usage Calculation

Unit: 7

Equation:	Electricity Consumption, kW =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$		Source: EPA Cost Spreadsheet
Where:	A =	0.1 x QB		EPA Cost Spreadsheet for industrial turbines
	QB =	23.03	MMBTU/hr	Maximum Annual Heat Input Rate
	CoalF =	1.0		EPA Cost Spreadsheet value for Oil and Natural Gas
	Heat Rate Factor (HRF) =	NPHR / 10		
	Net Plant Heat Input Rate (NPHR) =	8.2	MMBtu/MW	Default EPA Cost spreadsheet value
Calculation:	HRF =	0.82		
	A =	2.303		
	Unit 7 2016 Operating hours =	8,215.00	hours	2016 EI Submittal
	Electricity Consumption =	11.8	kW	
	Annual Electricity Consumption =	97.3	MWh/yr	

HARVEST MIDSTREAM

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December 13, 2019

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

RE: Submittal Requirements for Process Flaring and Startup, Shutdown, and Maintenance (SSM) Flaring as part of the Regional Haze Four-Factor Analyses

Dear Mr. Singleton:

Harvest Four Corners, LLC is repsonding to the November 14, 2019 request from New Mexico Environment Department for the review of process flaring and Startup, Shutdown, and Maintenance (SSM) flaring as part of the Regional Haze four-factor analyses.

Harvest Four Corners submitted a four-factor analysis for both the Kutz Canyon Processing Plant and San Juan Gas Plant on October 31, 2019. These analyses were conducted in accordance with the federal Clean Air Act, 42 U.S.C. §7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule) as well as the guidance provided by New Mexico Environment Department as received in the July 18, 2019 request to perform four-factor reasonable progress analyses.

Per NMED Guidance from July 18, 2019, *"In accordance with the Regional Haze Rule, NMED requested that a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis."*

The Kutz Canyon Processing Plant has two flares, units 28 and 36. Unit 28 is the plant flare and unit 36 is a control for the TEG dehydrator. The San Juan Gas Plant also has two flares, units 9 and 16. Unit 9 is a plant safety system flare and unit 16 is a staged blowdown flare that works in conjunction with the system flare.

After an extensive review of the equipment at both Kutz Canyon Processing Plant and San Juan Gas Plant it was determined that none of the flares have a potential to emit (PTE) above the de minimus thesholds of 10 pounds per hour and 5 tons per year for either NO_X or SO_2.

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Furthermore, Harvest would like to advise the NMED of their judgement that the flares at both Kutz Canyon and San Juan facilities' potential contribution to regional haze at the Mesa Verde National Park Class I area are such that it does not justify either facility being selected for this assessment for further evaluations of flares. Neither facility has a PTE associated with flares for SO_2 emisions and the NO_X emissions for each flare are below the de minimus thesholds for evaluation. Furthermore, NO_X emissions are not the dominant visibility impairing pollutant at Mesa Verde, and, for that reason, further reductions in NO_X emissions are unlikely to have a significant effect on visibility conditions.

Harvest appreciates the opportunity to present its views on the issues concerning possible reasonable progress assessments for the second planning period of the regional haze program with respect to Harvest Four Corners' Kutz Canyon Processing Plant and San Juan Gas Plant.

If you have questions or require additional information, please contact me at (505) 632-4625 or by e-mail at msmith@harvestmidstream.com.

Sincerely,

Monica Smith
Harvest Four Corners, LLC
MonicaSmith

REGIONAL HAZE FOUR-FACTOR ANALYSIS
NMED FOLLOW-UP LETTER RESPONSE

Harvest Four Corners, LLC, San Juan Gas Plant

Prepared By:

Adam Erenstein – Manager of Consulting Services
Michael Celente – Senior Consultant
Rachel Reese – Consultant

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March 2020

Project 193201.0199

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The NMED posed the following questions regarding the emissions control options Harvest presented for the turbines and engines located at the San Juan Gas Plant.

NATURAL GAS FIRED SIMPLE CYCLE TURBINES

Provide details of the Good Combustion Practices utilized at the plant including routine inspections, maintenance and training schedules. It is unclear if these practices are fully optimized or conform to permit conditions alone.

Harvest complies with the periodic testing pursuant to A205 in order to monitor NOX and CO emissions of the current Title V operating permit, P124R2. A copy of the current SSM Plan includes maintenance and inspection schedules and is included within Appendix B.

Harvest implements good combustion practices as prescribed by the manufacturer and required permit conditions. These include, but are not limited to:

- Manufacturer recommended maintenance
- Training of personnel in proper equipment maintenance and operations
- Routinely scheduled inspections
- Overhauls as required or recommended by the manufacture
- Use of pipeline quality natural gas

i. Provide documentation of your communications with Siemens to support the determination that dry low-NO_X (DLN) control options are technically infeasible for Units 1-3 and Rotating Spare.

These are included in Appendix A.

ii. Include a discussion of additional control measures for NO_X emissions including catalytic combustion and DLN technology available from other manufacturers. A four factor analysis should be completed for all technically feasible options.

These are included in Appendix A.

iii. Provide vendor specifications for the Solar SoLoNO$_X$ (i.e., DLN control) combustion technology to include the guaranteed NO_X emission rates used in cost analysis, the cost information, recommendations, and equipment specifications for the turbine control estimates.

These are included in Appendix A.

iv. How will upgrading units 4-7 with SoLoNO$_X$ affect the turbine capacities and the emission rates of NO_X and CO?

According to documentation received from Solar, the SoLoNO$_X$ unit would reduce the NO$_X$ exhaust concentration to 15 ppm. According, to AP-42, CO emissions would be increased from the implementation of this control, but Solar has not provided any guidance on the magnitude of the emission increase.[1]

v. Provide documentation of your communications with Siemens and Solar that supports the conclusion that water injection is not technically feasible for these units.

These are included in Appendix A.

vi. Provide supporting data and information for the determination that Selective Catalytic Reduction (SCR) systems are a technically infeasible control measure. Include documentation from site engineers verifying exhaust gas temperatures and space limitations at the facility. Consider and discuss exhaust gas temperature control devices and catalysts with higher operating temperatures (e.g., zeolites). Additionally, provide clarifying information regarding the additional energy demand SCR would require and expansion of current power generation capacity. Provide a cost analysis if this determination is based on cost and not technical feasibility.

This is included in Appendix A. SCR is not supported by Solar or Siemens and neither are other proposed technologies – Solar only supports the use of SoLoNO$_X$ for emission reductions on their turbines. San Juan would also need to install additional sources of electricity to meet the power demand required to support SCR.

vii. Please consider and include a discussion on limiting turbine operating hours or shutting down turbines that are no longer needed to reduce emissions.

Harvest cannot commit to decreasing turbine capacity as the facility has contractual obligations to process specific amounts of gas. Shutting down units or limiting hours of operation would reduce the facility's capacity and have substantial effects on both producers and consumers of natural gas. Decreases in the maximum capacity could impose a strain on facilities located in the San Juan and this is not something that Harvest can commit to.

viii. Provide the electronic spreadsheets used for control technology cost calculations.

These have been provided to the NMED.

[1] AP-42 Section 3.1.4.2 Stationary Gas Turbines, Control Technologies, Dry Controls.

APPENDIX A: VENDOR DOCUMENTION

From: McMahon, Jay
To: Monica Smith
Subject: [EXTERNAL] Avon Emissions Options
Date: Monday, September 23, 2019 9:47:42 AM

As per our discussion.

Right now there are no emissions reductions system available at this this point. That said, there are two (future) options for on emissions reduction.

1. Dry Low Emission Fuel and Combustion System
2. Water Injection System

The unfortunate part is neither are available yet.

DLE System

There have been a few DLE A20's built, but we really don't know much about them. Siemens has launched a project for a MK2 version of the DLE system. At this point I am not at liberty to give details on emissions levels but I can say their emissions target levels are a substantial reduction to what you have now. Right now it looks like this mod is 2-3 years out.

The mod will obviously include substantial engine, package and controls modifications. The DLE conversion would only be available from Siemens licensed overhaul shops for the engine mod and Siemens themselves on the package and controls mods.

Water Injection

There are no water injected A20's right now but Siemens recognizes the need for emissions reduction and is not looking at the development of a water injection mod. On other engine models I have experience with, the engine mods are normally consigned to fuel burners and flame tubes, but there are substantial package mods required as the water you inject must be absolutely pure so you would need a water treatment system. I am sure there would be controls modifications required as well. As for time line, we do not have one at this time.

As with the DLE system, water injection conversion would only be available from Siemens licensed overhaul shops for the engine mod and Siemens themselves on the package and controls mods.

Regards,

Jay McMahon
Vice President,
Sales - Americas
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Solar® Turbines

A Caterpillar Company

Powering the Future Through Sustainable, Innovative Energy Solutions

SOLONOX DRY LOW EMISSIONS TECHNOLOGY

Solar Turbines is a leader in pollution-prevention technology. Since the introduction of SoLoNOx™ in 1992, our dry low emissions technology advancements have prevented the production of more than 5.8 MM tons of NOx emissions. This represents a reduction of 75-90% from conventional combustion baselines for natural gas fuel.

Solar has unrivaled experience within the industry with more than 3500 SoLoNOx gas turbines with over 312 million operating hours located around the world.

Fuel options include natural gas, ultra low sulfur diesel (ULSD), associated gases, LPG and kerosene.

Low NOx Emissions Warranty: Pipeline natural gas emissions avalable at 9, 15, 25 or 38 ppm NOx @15% O2 on select models. ULSD emissions levels range from 58 to 96 ppm NOx @15% O2 on select models.

Wide Low NOx Emissions Operating Range: Single shaft 50-100% load, two shaft 40-100% load down to low ambient temperatures.

Available warranty emissions levels, operating range, and ambient temperature range vary by product and rating. Please contact Solar for more information.





Dry Low Emissions 101

DLE (dry low emissions) or lean-premix combustion reduces the conversion of atmospheric nitrogen to NOx by reducing the combustor's flame temperature. Since NOx formation rates are strongly dependent on flame temperature, lowering this temperature is an effective strategy for reducing NOx emissions. Lean combustion is enhanced by premixing the fuel and combustor airflows upstream of the combustory primary zone. DLE eliminates the need for water or steam injection or exhaust cleanup, which benefits the environment at a lower cost.

Additional Information

Internet: **www.solarturbines.com**
Email: **infocorp@solarturbines.com**
Phone: **+1-619-544-5352**

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DSSOLONOX/0419/EO

From: Joey Guillen [mailto:Guillen_Joey@solarturbines.com]
Sent: Monday, February 17, 2020 11:06 PM
To: Monica Smith <msmith@harvestmidstream.com>
Subject: [EXTERNAL] RE: Harvest - 4 Factor San Juan and Kutz

HI Monica,

Please see the attached Product Info Letters (PIL) and Spec Sheets on both the Centaur Generator Set and Compressor set. As well as combustion technology.

As far as wet NOx systems go, it is clearly stated on our spec sheets we no longer offer this technology. It is an outdated technology that requires more parts, maintenance and extremely clean water which equals additional cost for our customer and does not preform as well as our current SoLoNOx technology. Instead we continue to improve on this technology and pass the savings along to our customers from having to maintain additional systems that do not do as well in lowering emissions.

Solar's current stance on SCR's is on a case by case business. However as we are not SCR manufacturers we will currently not warranty or maintain these systems. Being that there are too many ways to construct these types of systems or standardize them based on customer needs, it makes it a difficult avenue for our company to pursue. We stand firm on our SoLoNOx technology being the best solution to lower emissions. It's the most environmentally friendly, cost effective and quickest way to reduce emissions.

FYI I'll be in the FCA office tomorrow morning if you'd like to chat about it. Let me know if this helps. I think I may need to provide you with performance runs to show the emissions guarantees mentioned. However I was waiting to get some clarification from one of our applications engineers before I send that information over.

Thanks!

Cheers,
Joey Guillen
CS – Account Manager
Domestic West Odessa
C: 504-343-0734
O: 432-688-8010
Guillen_Joey@SolarTurbines.com
Solar Turbines Inc.

APPENDIX B: GOOD COMBUSTION PRACTICES

SSM Plan Omitted for Brevity

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October 23, 2020

Mr. Michael Baca
Control Strategies Manager
New Mexico Environment Department Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico, 87505-1816

Harvest Four Corners, LLC is submitting this response to your August 31, 2020 follow-up email regarding the 4-Factor Analyses for the Kutz Canyon Processing Plant (Kutz) and the San Juan Gas Plant (SJGP). The attachments have been labeled to correspond with each item outlined in your email.

0. Harvest used the 5.5% interest rate based on the default rate at the time of the analysis to estimate costs (2016 year) and you are not opposed to NMED using an updated interest rate (e.g., 3.25%) in our cost analysis.

   While responses to the following items are based on a 5.5% interest rate, Harvest Corporate has recommended that analyses should be based on a 7.5% interest rate, the rate at which money has recently been borrowed.

1. Electronic spreadsheets (i.e., Excel files) and vendor quotes for cost calculations. Harvest indicated that vendor quotes have been difficult to obtain (i.e., CBT for engines) and may not be available, but will provide more information on their efforts to obtain these and the basis to estimate costs.

   See the attached spreadsheet and vendor quotes (*Att1K (filename)*) for the Solar SoLoNOx upgrades for Kutz Canyon. Solar is preparing quotes for the SJGP upgrades. The attached spreadsheet is based the 2019 4-Factor packet submittal, but the vendor quotes were requested after August 31, 2020 conference call.

2. Information for the Kutz Canyon facility (Kutz I) that was shared with our permitting group regarding future plans for permitting, facility operations, shutdowns, etc. With the continuing decline in natural gas production in the San Juan Basin, it is no longer economically viable to operate all equipment at the Kutz Canyon Processing Plant, and thus Harvest will discontinue operation of the Kutz I lean oil plant portion of the facility. The equipment to be decommissioned includes:

   a. Unit 16 – Clark HRA8 refrigerant compressor R4;
   b. Unit 17 – Clark HRA8 refrigerant compressor R5;
   c. Unit 18 – Clark HRA8 refrigerant compressor R6;
   d. Unit 22 – 23.1 MMBtu/hr Wheco heater H1;

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e. Unit 23 – 9.57 MMBtu/hr Alcorn heater H2;
f. Unit 24a – Kutz I EG dehydrator;
g. Unit 24b – Kutz I dehydrator reboiler;
h. Unit 37a – Waukesha 5794LT refrigerant compressor;
i. Unit 37b – Waukesha 7042GL refrigerant compressor (never installed);
j. Unit 39 – cooling tower; and
k. Tank T6438 – Blanco/Hare condensate tank and associated EVRU

3. Clarification about the use and generation of electricity at each plant including a list of the units used for compression and generating electricity.
   a. At Kutz, as currently permitted, Units 1 through 8, 16, 17 and 18 compress inlet or residue gas, while Units 37a or 37b compress propane for the Kutz 1 lean oil plant. Units 29 and 30 (Gen A and Gen B) generate electricity.
   b. At SJGP, Units 1, 2 and 3 compress inlet and residue gas, while electricity is generated by Units 4, 5, 6 and 7.

4. Technically feasibility of installing line electricity to the plants and replacing compression units with electric motors. Attachments *Att4K Kutz Electrical 9.8.2020* and *Att4S SJ Electrical Conversion* provide the cost estimate of replacing gas-fired compressor drivers with electrical motors.
   Adding 3 VFD motors to replace the units used for compression only, would require 15,000 hp motor variable speed for each. A building housing the three VFD motors of that size would have to be built across the road with land purchase. The power currently produced wouldn't be near enough for one VFD motor, much less all three. This would require a substation to be built across the road also. Modifications to the plant would have to be made, and real estate found to have heaters installed for heating the hot oil, which currently uses the waste heat from the turbines. Without the hot oil, the plant cannot make product spec. Additionally, these type and size of motors with a substation to start them would probably require very high voltage technicians that are qualified to work on them; nobody currently working at SJGP is line voltage qualified.

5. Confirmation that retrofit costs were included in your SCR analysis for the Solar turbines at San Juan GP.
   The SCR cost were derived using the EPA Cost Control Manual for SCRs. Within this calculation is an option for retrofit which was chosen and a designation of a Retrofit Factor (RF). An RF of 1.o was chosen for this calculation which is incorporated for the cost. Based on the Chapter 2 Selective Catalytic Reduction" from June 2019 , "a retrofit factor of 1 should be used for average retrofits. The equations may overestimate costs for

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some simple retrofits of existing plants. For retrofits that are more complicated than average, a retrofit factor of greater than 1 can be used to estimate capital costs provided the reasons for using a higher retrofit factor are appropriate and fully documented."

6. Clarification on the basis and use of incremental costs for SCR.
   Upon evaluating the calculation for incremental cost this appears to only be the difference in cost between the installation of SoloNox versus SCR and does not change the individual evaluation of the cost of the SCR.

7. Additional information about the space limitations for installing SCR.
   As with conversion to electricity, installation of SCR for turbine exhaust controls would also require purchase of real estate across the road. Routing the turbine exhaust to the ammonia/urea reagent storage across the road is technically infeasible the exhaust temperature would fall below reaction temperatures. Therefore, it would be necessary to pump the reagent to the existing exhaust stacks that have been retrofitted to accommodate the catalyst. In addition to the costs of remotely storing the reagent, there is also a significant safety hazard moving the reagent from storage and across the road to the exhaust stacks.

Thank you for your assistance with this analysis. Please email or call me (msmith@harvestmidstream.com, (505) 632-4625) if we can provide any additional information.

Sincerely,

Monica Smith

Monica Smith
Environmental Specialist

Attachments

Budget Summary

Program: SJGP Electrification

	Item	Work Order	Type	QY	Original Baseline Budget	Budget at Completion
FEUS	**New Electrical Sub-Station**		**Project**	**1**	**25,000,000.00**	**25,000,000.00**
SJGP	**Project Engineering & Design**		**Project**	**1**	**150,000.00**	**150,000.00**
SJGP	**Internal Labor**		**Project**	**1**	**100,000.00**	**100,000.00**
SJGP	**Arc Flash Study**		**Project**	**1**	**75,000.00**	**75,000.00**
SJGP	**UPS & Batteries Upgrades**		**Project**	**1**	**78,000.00**	**78,000.00**
SJGP	**Grounding Beds**		**Project**	**1**	**150,000.00**	**150,000.00**
SJGP	**Land Purchase (Unk)**		**Project**	**1**	**50,000.00**	**50,000.00**
SJGP	**Construction (SJ Plant)**		**Project**	**1**	**1,000,000.00**	**1,000,000.00**
SJGP	**New Motor, VFD, Transformer**		**Project**	**3**	**2,500,000.00**	**7,500,000.00**
SJGP	**FEUS (Farmington Electrical Utility System)**		**Project**	**1**	**250,000.00**	**250,000.00**
SJGP	**New Conduit, Junction Boxes, Breaks**		**Project**	**Various**	**100,000.00**	**300,000.00**
SJGP	**Compressor Gearbox**		**Project**	**3**	**500,000.00**	**1,500,000.00**
SJGP	**DCS Upgrades**		**Project**	**3**	**250,000.00**	**750,000.00**
SJGP	**SJ High Voltage Maintenance**					
SJGP	**Monthly Electric Service Bill**		**Reoccurring**	**12**	**150,000.00**	**1,800,000.00**
SJGP	**High Voltage Electrical Maintenance**		**Reoccurring**	**12**	**8,000.00**	**96,000.00**
SJGP	**Training Personnel (> 13.8kV)**		**Reoccurring**	**2**	**10,000.00**	**20,000.00**
SJGP	**Contingency**		**Project**	**1**	**2,000,000.00**	**2,000,000.00**

32,371,000.00 **40,819,000.00**

From: Monica Smith <msmith@harvestmidstream.com>
Sent: Friday, February 26, 2021 1:55 PM
To: Baca, Michael, NMENV
Cc: Jones, Mark, NMENV
Subject: [EXT] RE: [EXTERNAL] RE: Harvest 4FAs Follow-up Discussion
Attachments: Harvest - Pricing Term Sheet (Final).pdf; OD21_5029_LE_Harvest_San Juan Sta G-1300A Controls Upgrade.pdf; OD21_5030_LE_Harvest_San Juan Sta G-1300B Controls Upgrade.pdf; OD21_5031_LE_Harvest_San Juan Sta G-1300C Controls Upgrade.pdf; OD21_5032_LE_Harvest_San Juan Sta G-1300D Controls Upgrade.pdf; OD20-27963 Harvest Midstream San Juan Gens NOx_PSU Conversions201014JLG.PDF

Follow Up Flag: Follow up
Flag Status: Flagged

Michael,

Please see the attached items as well as the responses provided below.

1.) Harvest used a 5.5% interest rate in their responses and indicated that Harvest Corporate recommends a 7.5% interest rate for use in the 4-Factor Analyses. We have to document company specific interest rates in the form of a letter from the chief financial officer for the institution that lends to your company, or from an official with your company (your company's CFO, for instance) that is in a position to know your company's costs of debt and equity. Otherwise, we plan to use the current prime rate of 3.25% in the cost calculations. – Harvest – Pricing Term Sheet, attached

2.) Have you received quotes from Solar for the SJGP upgrades? – (5) attachments included from Solar for San Juan Gas Plant, (all 5 docs start with OD)

3.) Harvest indicates that equipment associated with the lean oil plant of Kutz I will be decommissioned. Under the Regional Haze Rule, emission limitations and reductions must be permanent and federally enforceable. Our review of Air Quality Bureau's permitting records does not show a recent New Source Review permit application for this action. Please provide more information about your plans to modify your permits including any recent communications with AQB permitting staff indicating your commitment to permanently discontinue operation of the Kutz I lean oil plant. – We just started internal discussions about the removal of the Kutz I equipment. We felt that we needed to wait before proceeding with the permit application to ensure that the plant could operate without any issues before de-permitting the equipment. Internal discussions have begun, and communications with NMED will be upcoming as well as the application submittal. We are currently working through our Annual Reports, such as Emissions Inventory and Green House Gas, which take precedent based on the submittal deadlines.

This is the current list of equipment that we plan on removing from the Kutz Permit, we may be adding a couple more items, in the permit application.

EU	Equipment Name
16	Clark Reciprocating Engine (R4)
17	Clark Reciprocating Engine (R5)
18	Clark Reciprocating Engine (R6)
22	Wheco Heater (H1)

23	Alcorn Heater (H2)
24	Kutz I EG Dehydrator
37a	Waukesha L5794LT Engine refrigerant compressor
37b	Waukesha L7042GL Engine (never installed)
39	Cooling Tower
T6438	Blanco-Hare Condensate Tank (& EVRU)

4.) Do the Operation and Maintenance (O&M) costs provided for in your Four Factor evaluation of applicable equipment reflect the incremental cost of O&M for additional control? In other words, are these costs over and above those already realized for the units? – Both Plant Foreman feel as though the numbers provide are correct. They did not feel that the numbers provided were over and above the cost already realized for the units.

Please let me know if you have any additional questions or need additional information.

Thank you,

Monica Smith
Harvest Four Corners, LLC
msmith@harvestmidstream.com
(505) 632-4625 - office
(505) 947-1852 - cell

Confidential Term Sheet and Attachments Containing Confidential Vendor Information Omitted

From: Kevin Reese <kreese@hilcorp.com>
Sent: Monday, July 31, 2023 2:14 PM
To: Baca, Michael, ENV <michael.baca1@env.nm.gov>
Cc: Clara Cardoza <ccardoza@hilcorp.com>
Subject: [EXTERNAL] SJGP Regional Haze Information

CAUTION: This email originated outside of our organization. Exercise caution prior to clicking on links or opening attachments.

Michael,
Attached is the information we have for the Regional Haze project.

Thanks,
Kevin

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CITY OF FARMINGTON, NEW MEXICO
ELECTRIC ENGINEERING
101 N Browning Parkway
Farmington, NM 87401
Engineering (505) 599-8300 or (505) 599-8451
New Service (505) 599-8310, 599-8312 or 599-8317
Fax (505) 599-8421
www.fmtn.org

July 20, 2023

Mr. Paul Harris
c/o Hilcorp Energy
61 County Road 4900
P.O. Box 217
Bloomfield, NM 87413
Ph: 505-632-4937

Subject: Electrifying Three 17,000 horsepower Motors at the Hilcorp Facility

Dear Mr. Harris,

I hope this letter finds you well. This is a response to your recent request. You had approached the Farmington Electric Utility System (FEUS) in late June requesting a cost estimate to electrify three (3) 17,000 horsepower (hp) motors at the Hilcorp facility located on the corner of Saiz Lane and Arizona Ave in Bloomfield, New Mexico. First of all, thank you for your inquiry. As I was contemplating a response to your request, it was suddenly obvious that the present configuration of the Farmington electric system can in no way provide service for load of this magnitude without significant additional infrastructure.

A 17,000 horsepower motor is effectively 17MVA of electrical load when motor efficiency and power factor are considered. Three of these motors would then represent a minimum of 51MVA electrical load. This does not account for motor starting, which would require deeper investigation. For reference, the all-time maximum FEUS system peak demand was 206MVA back in 2006. In 2022, the system peak was 193MVA. Thus, the additional 50MVA represents roughly a 25% increase in system demand. Although FEUS would be delighted to serve this load, it would be a bad business model for the Utility to have an additional 25% of system capacity "just lying around".

As mentioned above, accommodating this amount of load would require significant infrastructure upgrade to the 115kV system in addition to the installation of a new substation facility required to serve it. Presently the transmission line traversing east and west just to the north of the Hilcorp facility is built to FEUS maximum standards. Specifically, the conductor is made of 795kcmil conductor, good for up to 135MVA, but it is routinely modeled at near maximum loading conditions. The electric utility must design for and build to the anticipated system peak loads under various outage scenarios (called "contingencies") which is why the T-line, despite having seemingly adequate capacity, does not actually have that capacity available. Therefore, effectively, an additional 50MVA of transmission capacity would need to be built into the existing 115kV transmission line by adding a second 795kcmil conductor.

For your information, 795kcmil ACSR "Drake" conductor has a diameter of slightly more than 1 inch. ACSR stands for Aluminum Conductor Steel Reinforced. It has a core made of seven strands of steel, overlaid with 26 strands of aluminum alloy conductor and weighs about a pound per foot. It would seem that adding this second conductor is overkill, needlessly doubling the existing 135MVA to 270MVA, when only an additional 50MV is required. Multipronged reasons exist as to why this second conductor needs to be 795ACSR, and I am prepared to discuss them with you in person. Outlining them here would make this long letter even longer. Suffice it to say that several entire industries filled with many lifetime careers have been made off of electrical cable design, testing, installation, and operation.

Also, building a new transmission line could be investigated, but easement issues typically constitute "deal breakers" for transmission line projects now days. Either way the T-line would need to terminate near a power source (a power plant or grid interconnection point on the cusp of the FESU Service Territory) that could provide the additional 50MVA of load. In today's market, building a new 115kV transmission line could easily top $1,000,000 per mile. Upgrading the existing T-line could cost about 80% of that or $800,000 per mile. The length of the line depends on where the interconnection point or power source would be. In the extreme case, the line would have to be rebuilt all the way back to the Shiprock Substation, or approximately 40 miles for a total cost of about $40M. That is just for the transmission line.

As for the substation, there are a number of possible configurations. Let me just give you the worst-case estimate. A five-breaker ring bus would be required. This would serve as a terminus for the 1) input and the 2) output of the transmission line. It would also provide the point of service for the three (3) motors individually [3), 4) and 5)]. Each motor would be served by a three-phase 20MVA transformer, 115 to 13.8kV. The metering point would be at the 13.8kV level indicating that Hilcorp would own all facilities thereafter. If Hilcorp can serve its motors at 13.8kV, then no further transformation would be necessary. If a different voltage is required – again, worst-case – then three additional 20MVA transformers are needed to convert 13.8kV to that specific service voltage.

So, a five-breaker ring bus substation facility to include grading, foundations, conduits, control cable, ground grid, gravel, steel supports, twelve disconnect switches, five breakers, fifteen voltage transformers (for instrumentation), fence and security, the control building, relays, SCADA, communications, battery backup, AC/DC lighting and control, and HVAC installed would cost around $8 million. Then you will need six (6) 20 MVA transformers at a cost of just under $1M each, or about $6M. Add all substation components together and along with 30% for testing and commissioning, the sum is slightly more than $18 million. That is just for the substation.

Thus, the total cost of 115kV T-line upgrade plus substation could be as high as $58 million. And before all this takes place, we will need to discuss power purchase agreements, construction agreements, ownership and maintenance agreements, environmental and archeological permitting, perhaps some easements, etc. Make no mistake: Requesting to serve a load of this magnitude from this utility – and I would guess from MOST utilities – would be a very expensive endeavor.

I hope this letter provides you with the information you need. Please contact me on my cell phone any time, 505-860-4104, voice or text (text preferred) should you wish to discuss this further.

Thank you for your attention.

John Armenta, P.E.
Electrical Engineering Manager
Farmington Electric Utility System

Cost Breakdown for electrification of Inlet and Residue Compression

	Per Unit Est.		
Engineering Survey Engineering firm, civil, structural, electrical			2,000,000.00
Demolition of existing structures Man power, heavy equipment and removal	$250,000.00		$750,000.00
Structural steel Unknown weight of motors	$500,000.00		$1,500,000.00
Concrete caisons and footers for structural steel	$350,000.00		$1,050,000.00
Installation of structure all fabrication associated, rebar, bolt up	$400,000.00		$1,200,000.00
Electrical installation To include cable trays, cable, terminations etc.	$420,000.00		$1,260,000.00
Unit installation crane into place, mill wright work	$250,000.00		$750,000.00
2 cranes	$360,000.00		$1,080,000.00
VFD/Filters	$2,500,000.00		$7,500,000.00
Motor enclosure w/ventilation necessary for protection from elements, A/C required for heat disappation	$750,000.00		$2,250,000.00
17K Hp motor	$1,500,000.00		$4,500,000.00
Gear Box Complete replacement for new gear ration requirements, coupling design	$1,000,000.00		$3,000,000.00
Unit down time Revenue loss for up to 6 months Unknown	45-60 days each		
Land purchase/Lease Unknown location options, availability or cost associated			
Infrastructure development w/ City of Farmington Unknown percentage of cost		$58,000,000.00	
		Subtotal	$26,840,000.00
		10% contingency	$2,684,000.00
		Total	$29,524,000.00

Solar® Turbines
A Caterpillar Company

Solar Turbines Incorporated

9330 Sky Park Court
San Diego, CA 92123
Tel: (858) 694-1616

July 11, 2023

Subject: Existing Centaur 40-4700S NOx

At this time, the lowest available NOx emissions warranty for existing 4700S turbines on an aftermarket basis are represented by 25 ppmvd referenced to 15% oxygen and valid for temperatures greater than 0F and for loads >= 50% when utilizing pipeline quality natural gas fuel.

Please call me at 1.858.505.8554 if you have any questions.

Sincerely,

Anthony Pocengal
Principal Environmental Engineer
Solar Turbines Incorporated

Caterpillar: Confidential Green

Solar maintenance costs

Current T4501's (hrs)	8,760	17,520	26,280	35,040	43,800	52,560	
Year	1	2	3	4	5	6	
T4501 Annual	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000		$ 75,000
T4501 Exchange						$ 410,084	$ 410,084
							$ 485,084
							div. by 6
							$ 80,847 maintenance cost per year/unit

T4501 Annual = Borescope, coupling parts & grease, gaskets, filters, misc. parts, materials and 3rd party labor. Not including company labor.
T4501 Exchange 45,000 to 50,000 hours = Annual parts and labor plus exchange, transportation, 3rd party labor for swapping turbine engine. Not including company labor.
T4501 no additional charge if run past agreed upon hours unless exchanged unit is damaged.

Proposed T4701S (hrs)	8,760	17,520	26,280	35,040		
Year	1	2	3	4		
T4701S Annual	$ 15,000	$ 15,000	$ 15,000		$ 45,000	
T4701S Exchange				$ 655,000	$ 655,000	
					$ 61,488	Hrs over 30K charge
					$ 761,488	
					div. by 4	
					$ 190,372	**maintenance cost per year/unit**

T4701S Annual = Borescopr, coupling parts & grease, gaskets, filters, misc. parts, materials and 3rd party labor. Not including company labor.
T4701 Exchange 35,040 hours = Annual parts and labor plus exchange, transportation, 3rd party labor for swapping turbine engine. Not including company labor.
T4701S Fired Hour rate for each hour above 30,000 is $12.20

Conversion to Centaur T4701S SoLoNox for all 4 units **$6,962,486** Based on costs calculated to possibly convert first 2 units in early 2024.

Hilcorp is considering converting 2 standard Solar Centaur units to low emissions Solonox units in early 2024 and then the next 2 in 2027.

COMPLIANCE TEST REPORT

FROM THREE

ROLLS ROYCE AVON 1535 SUPERMAXI CENTRIFUGAL INTERNAL COMBUSTION ENGINES (UNIT # C-101, C-201, C-301)

AND FOUR

SOLAR CENTAUR T4501 CENTRIFUGAL INTERNAL COMBUSTION ENGINES (UNIT # G-1300A, G-1300B, G-1300C, G-1300D)

OWNED BY

HILCORP ENERGY CO.

NEW MEXICO ENVIRONMENT DEPARTMENT
OPERATING PERMIT NUMBER P124-R3

LOCATED IN BLOOMFIELD, NEW MEXICO
AT THE

SAN JUAN GAS PLANT

TEST DATE: JUNE 7-8, 2022

TESTED BY

COMPLIANCE SERVICES AND TESTING

PROJECT NUMBER 2395

COMPLIANCE SERVICES & TESTING
P.O. Box 94191-87199
7108 Washington St. NE
Suite A
Albuquerque, NM 87109
(505) 681-4909 Phone
www.comptesting.com

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6) Appendices
A: Tabular Results Field Data Sheets
B: Example Calculations
C: Fuel Analysis, F-Factor Calculations, and Fuel Meter Calibration Certificates
D: Quality Assurance Activities
E: Calibration Gas Certifications
F: Datalog Records

Introduction

Hilcorp Energy Co. owns and operates the San Juan Gas Plant located at UTM Zone 13, UTMH 235.7 km, UTMV 4069 km, approximately 2 miles northeast of Bloomfield, New Mexico in San Juan County. The function of this facility is a natural gas processing plant that extracts and processes natural gas liquids and residue gas products from field gas.

Units C-101 (1), C-201 (2), and C-301 (3) are used to compress and transport gas throughout the facility. Units G-1300A (4), G-1300B (5), G-1300C (6), and G-1300D (7) are used for the production of electricity used at the plant.

Exhaust emissions tests for the effluents of nitrogen oxides (NO_X defined as NO + NO_2) and carbon monoxide (CO) were conducted on the seven turbines to prove compliance with Title 20, New Mexico Administrative Code, Chapter 2, Part 70, (20 NMAC 2.70), Operating Permits. The State of New Mexico Environment Department, Air Quality Bureau (AQB) Operating Permit Number P124-R3 is the regulating permit in place for this facility. The testing followed the protocol submitted to the NMED-AQB which outlined the procedures set forth in the Code of Federal Regulations, Title 40, Part 60, Appendix A, Methods 3A, 7E, 10, and 19. The results of the testing will show that the turbines passed the annual emission tests.

Table 1 - Background Data

Source Operator:	**Hilcorp Energy Co.** Attn: Clara Cardoza 1755 Arroyo Dr. Bloomfield, NM 87413 (505) 564-0733 cardoza@hilcorp.com
Test Contractor:	**Compliance Services and Testing** Attn: Chris Spencer 7108 Washington NE, Ste. A Albuquerque, New Mexico 87109 (505) 681-4909 Phone cspencer@comptesting.com
Test Participants:	**Compliance Services and Testing (CST)** Mike Whiting – Project Lead Richard Ramirez – Technician **Hilcorp Energy** Scott Davis – Automation Specialist
Test Dates:	June 7-8, 2022
Location:	San Juan Gas Plant located in Bloomfield, San Juan County, New Mexico at #61 County Road 4900.
Test Methods:	**40CFR60, Appendix A** O_2/CO_2 concentration by EPA Method 3A NO_X concentrations by EPA Method 7E CO concentrations by EPA Method 10 Volumetric Flow Rate by EPA Method 19

Summary of Results

Table 2 – Summarized Results

Avon Rolls Royce Turbine Information			
Unit Number	1	2	3
Equipment Number	C-101	C-201	C-301
Serial Number	33391	38389	37901
Test Results/Emission Limits			
NO_X (pph/tpy) **(56.3/246.4)**	18.66 / 81.72	19.84 / 86.89	18.35 / 80.38
CO (pph/tpy) **(9.6/42)**	5.51 / 24.12	2.41 / 10.57	3.85 / 16.86

Solar Centaur Turbine Information				
Unit Number	4	5	6	7
Equipment Number	G-1300A	G-1300B	G-1300C	G-1300D
Serial Number	OHK17-C7516	OHJ17-C5283	OHK17-C0580	OHK17-C8812
Test Results/Emission Limits				
NO_X (pph/tpy) **(15.9/96.8)**	13.56 / 59.41	12.68 / 55.54	14.41 / 63.12	13.31 / 58.31
CO (pph/tpy) **(2.3/10.0)**	0.96 / 4.22	1.02 / 4.46	0.68 / 2.96	0.85 / 3.74

Figure 1 shows the sample system diagram used for the testing and Table 1 lists the analytical analyzers and sensitivities. Appendix A contains all field and operational data along with the tabular results. Appendix B contains the example calculations. Appendix C contains the fuel analysis, fuel meter certificates, and CST's fuel calculations. Appendix D contains the quality assurance and quality control documentation. Appendix E contains copies of the calibration gases. Copies of datalog records are in Appendix F.

Remainder of Report Omitted for Brevity

D.9 IACX Roswell

Supporting documentation for IACX Roswell is provided below. Facility-specific documentation is provided first, followed by documentation pertaining to multiple facilities and/or the owner/operator. The following documents are included in this section (in reading order):

- Bitter Lake Compressor Station:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (11/2019)
    - Follow-Up Submittal 1/29/2020()
    - Follow-Up Submittal (11/4/2020)
    - Follow-Up Submittal (1/5/2021)

NMED Final Cost Evaluation
IACX Roswell - Bitter Lake Compressor Station

Facility Information

IACX Roswell, LLC - Bitter Lake	**Facility**
Two 1980s 2SLB RICE, 2250 HP	**Units**
C-891 and C-893	**Unit IDs**
Additional LEC Upgrades	**Evaluated Pollution Control**
2.0	**Post-control Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2020	**Calendar year associated with cost estimates**
2250	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		C-891	C-893	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 383,482	$ 383,482	1/5/21 update from IACX, vendor estimate	Equipment, install labor and materials for Turbocharger and Intercooler Upgrades
Other Direct Capital Costs 1 ($)	ODC1	$ 204,186	$ 204,186	1/5/21 update from IACX, vendor estimate	Existing Materials Upgrades (Oil Cooler and Supplemental Water-Cooling System)
Other Direct Capital Costs 2 ($)	ODC2	$ 98,832	$ 98,832	1/5/21 update from IACX, vendor estimate	Additional Equipment Upgrades Recommended (Modern Generation Jet Cell with ePCC System)
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Not specified by IACX
Total Capital Costs - Direct ($)	TCC	$ 686,500	$ 686,500	-	PEC + ODC1 + ODC2 + IDC
Additional Capital ($)	AC	$ 15,000	$ 15,000	1/5/21 update from IACX, consultant estimate	Permitting Cost
Total Capital Investment ($)	TCI	$ 701,500	$ 701,500	-	TCC + AC
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	IACX did not provide a company-specific rate
Useful Life (yr)	Y	20	20	1/5/21 update from IACX	Consistent with other FFAs
Capital Recovery Factor	CRF	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 68,812	$ 68,812	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	Engineering judgement	Incremental O&M of a LEC retrofit is expected to be negligible
Other Indirect Annual Costs ($/yr)	OAC	$ 28,060	$ 28,060	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 96,872	$ 96,872	-	ACC + OMC
NOx Control Efficiency (%)	Eff	-90%	-90%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate; Negative control efficiency and cost effectiveness due to the current emissions rate being less than the assumed post-control rate of 2 g/bhp-hr.
Baseline Actual NOx Emissions (ton/yr)	BAE	16.4	14.0	CY 2022 emissions testing and average operating hours (2016-2020)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by IACX
Projected Actual Emissions (ton/yr)	PAE	16.4	14.0	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	-14.9	-12.7	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**-$6,522**	**-$7,655**	-	TAC/ER; Jan 2021 cost info was originally provided in Nov 2020 and thus assumed to be in 2020$
Price Index	PI	1.34	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**-$8,740**	**-$10,258**	-	CE1 x PI

NMED Final Cost Evaluation
IACX Roswell - Bitter Lake Compressor Station

Facility Information

IACX Roswell, LLC - Bitter Lake	**Facility**
Two 1980s 2SLB RICE, 2250 HP	**Units**
C-891 and C-893	**Unit IDs**
Replacement with new RICE	**Evaluated Pollution Control**
0.3	**Post-control Emissions Rate (g NOx/bhp-hr)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired spark ignited lean-burn RICE >= 1875 bhp.

Supporting Information

2020	Calendar year associated with cost estimates
2250	Maximum Power Output (hp/unit)

Economic Evaluation

Cost Component		C-891	C-892	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 7,260,750	$ 7,260,750	9/8/20 info from El Paso Natural Gas (EPNG)	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $3227/hp cost metric as IACX did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered RICE.
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	IACX did not provide a company-specific rate
Useful Life (yr)	Y	30	30	ERG experience based on discussions with RICE manufacturers	
Capital Recovery Factor	CRF	0.0847	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 614,777	$ 614,777	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	-	Incremental O&M reasonably negligible
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 614,777	$ 614,777	-	ACC + OMC
NOx Control Efficiency (%)	Eff	72%	72%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	16.4	14.0	CY 2022 emissions testing and average operating hours (2016-2020)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by IACX
Projected Actual Emissions (ton/yr)	PAE	16.4	14.0	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	11.7	10.0	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 52,341**	**$ 61,429**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 and thus assumed costs are in 2020$
Price Index	PI	1.34	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 70,136**	**$ 82,315**	-	CE1 x PI

NMED Final Cost Evaluation
IACX Roswell - Bitter Lake Compressor Station

Facility Information

IACX Roswell, LLC - Bitter Lake	**Facility**
Two 1980s 2SLB RICE, 2250 HP	**Units**
C-891 and C-893	**Unit IDs**
Replacement with EMD	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
2250	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		All Units	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	IACX did not provide cost estimates for electrification. As a result, a Total Capital Cost metric of $2,084 (2023$/hp) was calculated using detailed cost information provided by other facilities. The TCI figure assumes no additional capital costs associated with substation or distribution line upgrades. This assumption underestimates costs given that IACX indicated on 7/7/23 that these upgrades would be needed to support electrification.
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ 9,378,000	See Note	
Additional Capital ($)	AC	$ -	-	
Total Capital Investment ($)	TCI	$ 9,378,000	See Note	
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	IACX did not provide a company-specific rate
Useful Life (yr)	Y	25	-	
Capital Recovery Factor	CRF	0.0897	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 841,307	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 566,704	-	AED + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 1,133,409	ERG calculation	Additional Electricty Demand assumes 60% load, 95% efficiency and a $0.10/kWh price
Associated non-electricity O&M ($/yr)	AOM	$ -	Engineering judgement	Assumed to be negligible
Annual Fuel Credit ($/yr)	AFC	$ (566,704)	ERG calculation	Assumed equal to 50% of AED
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 1,408,011	-	ACC + OMC
NOx Control Efficiency (%)	Eff	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	30.4	CY 2022 emissions testing and average operating hours (2016-2020)	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by IACX
Projected Actual Emissions (ton/yr)	PAE	30.4	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	30.4	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 46,312**	-	TAC/ER
Price Index	PI	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 46,312**	-	CE1 x PI

REGIONAL HAZE FOUR-FACTOR ANALYSIS

IACX Roswell, LLC

Bitter Lake Compressor Station

Prepared By:

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1. EXECUTIVE SUMMARY

In the 1977 amendments to the Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across the United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

> *(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A).*
>
> This is known as a four-factor analysis.
>
> *(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B).*
>
> The uniform rate of progress or improvement is sometimes referred to as the glidepath and is part of the state's Long Term Strategy (LTS).

The second implementation planning period (2018-2028) for national regional haze efforts is currently underway. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural or biogenic and manmade or anthropogenic sources of emissions. Using a Photochemical Grid Model (PGM), the Western Region Air Partnership (WRAP), in coordination with the EPA, is tasked with comparing anthropogenic source contributions against natural background concentrations.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for major sources and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I area. From this analysis, 24 facilities were identified by the NMED. On July 18, 2019 the NMED informed IACX Roswell, LLC (IACX) that its Bitter Lake Compressor Station (Bitter Lake) was identified as one of the sources contributing to regional haze at the Salt Creek WA Class I area.

In coordination with WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. In the NMED's July 18, 2019 notification letter to IACX, it specifies that any single piece of equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The equipment at Bitter Lake, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant are reported in Table 1.

Table 1. Summary of Equipment and Applicability of the Four-Factor Analysis

Equipment	NO_X PTE (lb/hr)	NO_X PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 PTE (lb/hr)	SO_2 PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
Cooper-Bessemer / GMVH-10C 2SLB RICE / Unit C-891	20.0	87.6	Yes	--	--	No
Cooper-Bessemer / GMVH-10C 2SLB RICE / Unit C-893	20.0	87.6	Yes	--	--	No

Once the applicability of equipment and pollutants has been determined, potential retrofit control technologies must be identified. In accordance with 40 CFR 51 Appendix Y and at the recommendation of the NMED,[1] this is primarily achieved by utilizing the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) data. In order to determine the most relevant and current retrofit controls available, the RBLC is queried for the previous ten years. Summaries of the result of this search are provided and discussed under Section 2 of this report. IACX engineers then reviewed the list of available retrofit technologies and performed a technical feasibility assessment for each control option. The four-factor analysis is then conducted for those controls that are technically feasible.

[1] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

2.1. TWO-STROKE LEAN-BURN ENGINES

Bitter Lake has two (2) natural gas-fired two-stroke lean-burn (2SLB) reciprocating internal combustion engines (RICE), Units C-891 and C-893, that are subject to this four-factor analysis. The only pollutant subject to evaluation for these units is NO_X.

2.1.1. Two-Stroke Lean-Burn Engines Background

Natural gas-fired RICE are separated into multiple design classes, including 2SLB, 4-stroke lean-burn (4SLB), and 4-stroke rich-burn (4SRB). The four-stroke design uses four strokes of the piston, or two turns of the crankshaft, to complete the power cycle. The two-stroke design completes the power cycle in a single revolution of the crankshaft. Rich-burn engines are designed to operate close to the stoichiometric, or chemically balanced, air-to-fuel ratio (around 16:1) with exhaust oxygen levels less than 4 %, while lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1), with exhaust oxygen levels of 12 % or more.[2]

NO_X is formed in reciprocating engines via three mechanisms:

(1) Thermal NO_X - the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion,
(2) Fuel NO_X - the evolution and reaction of fuel-bound nitrogen compounds with oxygen, and
(3) Prompt NO_X - the early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The Bitter Lake engines use natural gas fuel, which contains a negligible amount of nitrogen compounds. Therefore, the formation of prompt and fuel NO_X will be insignificant. This analysis will focus on thermal NO_X. The rate of NO_X formation through the thermal NO_X mechanism is highly dependent upon the air-to-fuel ratio, combustion temperature, and residence time at the combustion temperature. Maximum thermal NO_X formation occurs near the stoichiometric air-to-fuel mixture ratio because combustion temperatures are greatest at this ratio.[3]

NO_X reduction in natural gas-fired RICE can be accomplished by three general methods, as follows:

(1) Operational control methods, such as adjusting the timing or other operating parameters.
(2) Combustion control techniques, for example reducing the peak flame temperature by introducing inerts that limit initial NO_X formation.
(3) Post-combustion NO_X control technologies, which employ various strategies to chemically reduce NO_X.

The PTE from each engine is reported in the facility's Title V permit P047-R3, as well as above in Table 1.

[2] "Emission Control Technology for Stationary Internal Combustion Engines," Manufacturers of Emission Controls Association, 2015
[3] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"

2.1.2. Potential NO_X Controls for 2SLB Engines

Retrofit control options identified for 2SLB RICE were identified via comprehensive review of the RBLC and available technical literature and are summarized in Table 2. A detailed description and discussion of the technical feasibility and anticipated performance of each control is provided below.

Table 2. Potential Control Options for 2SLB RICE

Control Equipment	Technically Feasible	NO_X Control Efficiency
Selective Catalytic Reduction	**No**	**N/A**
Clean Burn Technology	**Yes**	**25% - 57%**
Good Combustion Practices and Fuel Selection	**Yes**	**Base Case**

2.1.2.1. Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust stream of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[4] The chemical reactions for this process are shown in the equations below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

An SCR system includes the catalyst, reagent storage tank, reagent injector, reagent pump, pressure regulator, and electronic controls to accurately meter the quantity of reagent injected as a function of engine load, speed, temperature, and NOx emissions to be achieved. The lifespan of the catalyst is primarily determined by the erosion caused by the flue gas, deactivation caused by ammonium bisulfate (NH_4HSO_4) poisoning, as well as the build-up and fouling by the catalyst.

In order for an SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 and 850 °F), dependent on the material of the catalyst. Exhaust gas temperatures greater than the upper limit will cause the NO_X and ammonia to pass through the catalyst unreacted.

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as ammonia slip. Unreacted reagent in the exhaust can form ammonium sulfates, which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.

For engines that typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia

[4] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

injection to gain the reductions needed.[5] In the case of Bitter Lake, the two engines run at ongoing variable loads. Therefore, an SCR is technically infeasible for the engines at Bitter Lake.

Finally, there has been no application of SCR on this model of Cooper engines (see attached RBLC results). A thorough twenty-year review of the RBLC tables was conducted and there were no examples of an SCR being used as a control for 2SLB engines. The lack of availability or comparable use of an SCR on these Cooper engines presents the case that this control technology is considered technically infeasible. Consequently, SCR is not evaluated further in this four-factor analysis.

2.1.2.2. Clean Burn Technology

Clean Burn Technology (CBT) is another term for utilizing combustion mixtures in engines with fuel-lean air-to-fuel ratios. This method of reducing NO_X emissions involves reconfiguring the engines by adding or enhancing an air-to-fuel ratio controller, making the unit capable of operating at more desirable ratios.

As described in Section 2.1.1 of this report, rich-burn engines are normally designed to operate close to the stoichiometric, or chemically balanced, air-to-fuel ratio of 16:1, while lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1). A combustion mixture with a higher air-to-fuel ratio results in reduced NO_X emissions, because using fuel-lean mixtures lowers the combustion temperature by diluting energy input. 2SLB engines are typically designed to operate at the high air-to-fuel ratios employed in CBT; however, further increasing the air-to-fuel ratio in lean-burn engines can decrease the NO_X emissions.[6]

In order to avoid derating the engine, combustion air must be increased at constant fuel flow. To achieve this, the engine will need to be retrofitted with a turbocharger, which forces additional air into the combustion chamber, as well as an automatic air-to-fuel ratio controller.

Many 2SLB engines, such as naturally aspirated engines, do not have identical air-to-fuel ratios in each cylinder, which can result in limited ability to vary the air-to-fuel ratio. To maintain acceptable engine performance at lean conditions, high-energy ignition systems (HEIS) have been developed that promote flame stability at very lean conditions.[7]

2SLB engines are mechanically capable of being retrofitted with more sensitive air-to-fuel ratio controllers and running on higher air-to-fuel ratio combustion to control NO_X emissions. Therefore, it has been determined that this method of NO_X control is feasible for the 2SLB engines at Bitter Lake. Air-to-fuel ratio adjustment generally achieves a 5 to 30% reduction in NO_X emissions; however, this reduction is very specific to each engine and typical loading[8].

The two units at Bitter Lake are currently equipped with turbochargers and efficient combustion air intercoolers. Based on manufacturer guidance, the addition of these clean burn technologies allows the engines to range from 1.74 to 3.04 g/hp-hr, which allows for a 25% to 57% reduction in NO_X emissions; thus, no further assessment of these control practices is included in this report.

---

[5] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
[6] State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines, State of New Jersey Department of Environmental Protection, 2003.
[7] Ibid
[8] Ibid

2.1.2.3. Good Combustion Practices and Fuel Selection

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from large natural gas-fired lean-burn stationary internal combustion engines; therefore, it has been determined that this method of NO_X control is feasible for the 2SLB engines at Bitter Lake. With that being said, these practices are currently in use at Bitter Lake. No further assessment of these control practices is included in this report.

3. SUMMARY & CONCLUSIONS

Based on a comprehensive review of the RBLC, available literature, and manufacturer's input of available control technologies for the natural gas fired engines located at Bitter Lake, IACX has determined that clean burn technology and good combustion practices are the only technically feasible control options for the two units. As IACX already deploys these control technologies, there are no further factors to evaluate.

Based upon actual emissions at the site, IACX will be modifying its permit this year to more closely match the actual emissions of the clean burn technologies that exist at the facility, which will remove the facility from Title V permit status.

4. SUPPORTING DOCUMENTATION

Appendix A – RBLC Analysis Table and Raw RBLC Review Table

Appendix A

RBLC Analysis for Natural Gas-Fired Lean-Burn Stationary Internal Combustion Engines – NO_x

	Control Technology	Selective Catalytic Reduction (SCR) [a,b]	Non-Selective Catalytic Reduction (NSCR) [b]	Clean Burn Technology	Good Combustion Practices and Fuel Selection [c]
IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	A nitrogen-based reagent (e.g., ammonia, urea) is injected into the exhaust stream downstream of the combustion unit. The reagent reacts selectively with NO_x to produce molecular N_2 and water in a reactor vessel containing a metallic or ceramic catalyst.	This technique uses residual hydrocarbons and CO in rich-burn engine exhaust as a reducing agent for NO_x. In an NSCR, hydrocarbons and CO are oxidized by O_2 and NO_x. The excess hydrocarbons, CO, and NO_x pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H_2O and CO_2, while reducing NO_x to N_2.[b]	Natural gas fueled engines that operate with a fuel-lean air/fuel ratio are capable of low NO_x emissions.	NO_x emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following EPA's "Good Combustion Practices" guidance document, good combustion practices can be maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices the unit will operate as intended with the optimal NO_x emissions.
	Other Considerations	Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as "ammonia slip." Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.	N/A	N/A	N/A
ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Not included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Not included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Included in RBLC for the control of NO_x emissions from large natural gas-fired lean-burn stationary internal combustion engines.
	Feasibility Discussion	Technically infeasible. For engines which typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia to gain the reductions needed.	Technically infeasible. The NSCR technique is limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes 4-stroke rich-burn naturally aspirated engines and some 4-stroke rich-burn turbocharged engines. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures.	Technically feasible.	Technically feasible.
RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency			25% - 57%	Base Case

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
b. U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
c. EPA Guidance document "Good Combustion Practices" available at: http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf.

Raw RBLC Review

RBLC ID	Facility Name	EPA Region	Permit Number	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Standard Emission Limit	Standard Emission Limit Unit	Cost Effectiveness	Incremental Cost Effectiveness	Cost Verified	Pollutant Compliance Notes
NE-0015	KN ENERGY, INC	7	56628R01	2-CYCLE LEAN BURN ENGINE, UNIT 2505E	NATURAL GAS	1000	HP	ALL CONTROLLED BY 2ND GENERATION CLEAN BURN CONTROLS.	Nitrogen Oxides (NOx)	2	G/BHP-H	0	0	N	standard units estimated using process information.
NE-0015	KN ENERGY, INC	7	56628R01	IC ENGINE, 2503E, COOPER GMVA-10	NATURAL GAS	1265	HP		Nitrogen Oxides (NOx)	12	G/BHP-H	0	0	N	standardized units estimated from process information
NE-0015	KN ENERGY, INC	7	56628R01	IC ENGINE, 2504E, COOPER GMVA-6	NATURAL GAS	750	HP		Nitrogen Oxides (NOx)	12	G/BHP-H	0	0	N	standardized units estimated from process information
NE-0015	KN ENERGY, INC	7	56628R01	IC ENGINE, 2511E, COOPER GMVA-6	NATURAL GAS	750	HP		Nitrogen Oxides (NOx)	15	G/BHP-H	0	0	N	standardized units estimated from process information

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VIA E-MAIL: mark.jones@state.nm.us; kerwin.singleton@state.nm.us

January 29, 2020

Mr. Mark Jones
Mr. Kerwin Singleton
NMED Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

RE: Response to the Request for Additional Information for Four-Factor Analyses under the Regional Haze Program

Dear Mr. Jones and Mr. Singleton:

This letter addresses the additional information request for the IACX Roswell LLC – Bitter Lake Compressor Station Four-Factor Analysis report received on December 23, 2019. For the Bitter Lake Compressor Station (Bitter Lake) there were a total of three item requests pertaining to the NO_X emissions for both engines. Please see the responses for each item request below.

1. *Provide the details regarding Good Combustion Practices (GCP) and the routine maintenance schedule and procedures that are currently used to mitigate nitrogen oxide (NO_X) emissions that are employed as the base case.*
   Response: Bitter Lake complies with the routine maintenance schedule pursuant to A201.A in TV Permit No. P047-R3. Bitter Lake complies with periodic testing pursuant to A201.B in order to monitor NO_X, CO, and VOC emissions. IACX operates the units per the manufacturer guidelines in order to mitigate NO_X emissions.
2. *Please provide an analysis of the technical feasibility of Non-Selective Catalytic Reduction (NSCR) as a retrofit control option for all engines that were evaluated in the Bitter Lake Compressor Station four-factor analysis for NO_X. Should it be determined that SCR is technically feasible, please complete a four-factor analysis for this technology.*
   Response: U.S. EPA, Ap-42, Section 3.2 "Natural Gas-Fired Reciprocating Engines" currently states, "To achieve effective NO_X reduction performance, the engine may need to be run with a richer fuel adjustment than normal. This exhaust excess oxygen level would probably be closer to 1 percent. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures." Also, in the report submitted on November 1, 2019, we included an RBLC table that further explains the infeasibility of NSCR on 2SLB engines.
3. *Please consider and include a discussion on the feasibility of replacing natural gas-fueled engines/turbines with commercial electric powered compressors.*
   Response: Per Appendix Y to Part 51—Guidelines for BART Determinations Under the Regional Haze Rule Section IV.D.1.5, "We do not consider BART as a requirement to redesign the source when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, we do not require the BART analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting on a per unit basis." This report is essentially a BART analysis with only 4 factors which are reviewed. IACX will only submit alternative control options and will not assess replacing equipment.

Please feel free to contact either myself at (505) 266-6611 or Tony Hines, Senior VP of Operations at IACX Roswell LLC at (972) 960-3219 if you have any questions regarding this response.

Sincerely,

MacKenzie Russell
Consultant

Cc: Tony Hines, IACX Roswell LLC

From: Rachel Reese
To: Butt, Neal, NMENV; Tony Hines; Adam Erenstein
Cc: Zyla, Rhett, NMENV; Jones, Mark, NMENV; Baca, Michael, NMENV; Singleton,Kerwin, NMENV; Homer Trujillo
Subject: RE: [EXT] RE: IACX 4FA
Date: Wednesday, November 4, 2020 5:34:23 PM
Attachments: image005.png
image006.png
image002.png
IACX_Bitter Lake_4FA Cost Estimate_2020-1104.xlsx

Good evening Neal,

Responses to your follow-up questions on the IACX Bitter Lake 4FA are below in blue and the cost effectiveness calculations are attached. Please feel free to reach out if you have any questions.

1. Bitter Lake already has Clean Burn Technology in use, specifically turbochargers and efficient combustion air intercoolers. However, we would like more information on the technical feasibility and cost numbers for additional CBT retrofit technologies.

   Based on conversations with the engine manufacturer, IACX has determined that some upgrades to the CBT retrofit technologies are technically feasible for the engines at Bitter Lake, but would have little to no reduction in emissions based on the stack test data recorded for the 2019 Emission Inventory due to the existing controls already in place. Cost effectiveness calculations are attached based on the quotes and emission guarantees provided by Cooper; however, the estimated emissions reductions and costs are based on a series of assumptions and it will be necessary to complete a thorough engineering study of the engines to determine what is truly feasible. Due to the overly conservative calculation methodology applied for Emission Inventories prior to IACX obtaining the site, the potential emission reduction has been calculated using the 2019 emission inventory submitted. The cost effectiveness of additional CBT on each engine is summarized below.

Unit	Total Capital Cost ($)	Annual O&M Cost ($)	Total Annual Cost ($)	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
C-891	$ 701,500	$ 174,750	$ 222,998	1.92	$ 116,063
C-893	$ 701,500	$ 174,750	$ 222,998	0.00	$ 222,998

2. We have values for the permitted allowable emissions for the engines at Bitter Lake, but we would like to know more about the actual NOx emissions and current operating hours for 2019; as well as the representativeness of those emissions in the future.

   The 2019 emission inventory was completed based on the most recent available stack test data at the time. Operating hours for each unit in 2019 are anticipated to be representative for future years.

Thank you,

Rachel Reese
Senior Consultant

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Trinity Consultants

IACX Bitter Lake Compressor Station

Amortization of equipment		
NMED Assumed Discount Rate - "r"	3.25%	
Life Expectancy of control equip (years) - "n"	20	

Cooper-Bessemer / GMVH-10C 2SLB RICE; Unit C-891			
Equipment, install labor and materials for Turbocharger and Intercooler Upgrades	$	383,482	<-- Cooper estimated
Existing Materials Upgrades (Oil Cooler and Supplemental Water-Cooling System)	$	204,186	<-- Cooper estimated
Additional Equipment Upgrades Recommended (Modern Generation Jet Cell with ePCC System)	$	98,832	<-- Cooper estimated
Permitting Cost	$	15,000	<-- Trinity estimated (includes estimated cost of labor and review fee)
Total Cap Investment - "P"	**$**	**701,500**	
Annualized TCI - "A"	$	48,248	<-- Based on interest rate, year and TCI per NMED calculation methodology
Annual O&M Costs:	$	174,750	<-- Trinity estimated; engine maintenance and labor costs, based on similar units *($75/BHP engine maintenance cost, 100 labor hours/yr at 60 $/hr)*
Total Annual Costs	**$**	**222,998**	
Baseline NOx Emissions (tpy)		**39.62**	<-- from 2019 Emissions Inventory submissions - AEIR
Estimated Controlled Emissions (tpy)		**37.70**	<-- Based on 2 g/hp-hr emission standard guarantee from Cooper
Emission Reduction (tpy)		**1.92**	
Engine Upgrades Cost: $/yr-ton	**$**	**116,063**	

Cooper-Bessemer / GMVH-10C 2SLB RICE; Unit C-893			
Equipment, install labor and materials for Turbocharger and Intercooler Upgrades	$	383,482	<-- Cooper estimated
Existing Materials Upgrades (Oil Cooler and Supplemental Water-Cooling System)	$	204,186	<-- Cooper estimated
Additional Equipment Upgrades Recommended (Modern Generation Jet Cell with ePCC System)	$	98,832	<-- Cooper estimated
Permitting Cost	$	15,000	<-- Trinity estimated (includes estimated cost of labor and review fee)
Total Cap Investment - "P"	**$**	**701,500**	
Annualized TCI - "A"	$	48,248	<-- Based on interest rate, year and TCI per NMED calculation methodology
Annual O&M Costs:	$	174,750	<-- Trinity estimated; engine maintenance and labor costs, based on similar units *($75/BHP engine maintenance cost, 100 labor hours/yr at 60 $/hr)*
Total Annual Costs	**$**	**222,998**	
Baseline NOx Emissions (tpy)		**21.75**	<-- from 2019 Emissions Inventory submissions - AEIR
Estimated Controlled Emissions (tpy)		**36.76**	<-- Based on 2 g/hp-hr emission standard guarantee from Cooper
Emission Reduction (tpy)		**0.00**	(2018 stack test recorded emissions less than Cooper guarantee. No anticipated reduction possible.)
Engine Upgrades Cost: $/yr-ton	**$**	**222,998**	

From:	Rachel Reese
To:	Butt, Neal, NMENV; Tony Hines; Adam Erenstein
Cc:	Jones, Mark, NMENV; Baca, Michael, NMENV; Singleton,Kerwin, NMENV; Homer Trujillo
Subject:	RE: [EXT] RE: IACX 4FA
Date:	Tuesday, January 5, 2021 9:14:48 AM
Attachments:	image006.png image007.png image008.png image002.png IACX_Bitter Lake_4FA Cost Estimate_2021-0105.xlsx

Good morning,

Responses to your questions regarding the IACX Bitter Lake 4FA are below in red and the updated cost estimate spreadsheet is attached. Please let me know if you have any additional questions.

Thank you,

Rachel Reese
Senior Consultant

P 505.266.6611 M 505.920.2177
9400 Holly Avenue NE, Bldg. 3, Suite 300 | Albuquerque, NM 87122
Email: rreese@trinityconsultants.com

From: Butt, Neal, NMENV <Neal.Butt@state.nm.us>
Sent: Tuesday, December 08, 2020 1:12 PM
To: Rachel Reese <RReese@trinityconsultants.com>; Tony Hines <tonyhines@iacx.com>; Adam Erenstein <AErenstein@trinityconsultants.com>
Cc: Jones, Mark, NMENV <Mark.Jones@state.nm.us>; Baca, Michael, NMENV <michael.baca1@state.nm.us>; Singleton,Kerwin, NMENV <Kerwin.Singleton@state.nm.us>; Homer Trujillo <homertrujillo@iacxroswell.com>
Subject: RE: [EXT] RE: IACX 4FA
Importance: High

Good Afternoon Rachel,

I would like to follow up with you on your submitted analysis.

1. 1. I think the calculations for "Estimated Controlled Emissions" at 2g/hp-hr may be incorrect. Your Excel formula (=2*'C-891'!B11*'C-891'!B12/2000/453.6) references the cell for "Maximum Horsepower" rating (i.e. Cell B-12) rather than the "Requested Horsepower" (i.e. Cell B-13) (as done for other calculations; e.g. "Heat Input Rating", " Hourly Fuel Usage", "Uncontrolled Emissions for Criteria Pollutants, VOCs, and HAPs"). If Requested hp is used, this would reduce the "Estimated Controlled Emissions (tpy)" from 39.62 tpy to 23.70 tpy for C-891; and from 36.76 to 22.73 tpy for C-893. This would then improve the cost effectiveness from $116,063/yr-ton to $14,002/yr-ton for

engine C-891; but did not change the cost effectiveness for engine C-893 ($222,998/yr-ton), which brings up the following question.

I have updated the cost estimates per your notes in the attached spreadsheet.

2. You indicate that for engine C-893, "2018 stack test recorded emissions less than Cooper guarantee. No anticipated reduction possible." It seems counterintuitive to me that adding additional pollution-control equipment would increase emissions.

   You're correct that the additional equipment would not increase emissions; however, the guaranteed output NOx emissions from Cooper for the available additional pollution control equipment are higher than the emissions recorded for stack testing. Therefore, there's no guarantee that the available control will be able to reduce emissions further.

3. What is the estimated "Compliance Time (yr)" for the CBT upgrades?

   The anticipated compliance time is 24 months to budget, plan, and install the control equipment, provided the supplier can guarantee a reduction in emissions below historically tested levels.

4. What is the anticipated "Energy / Non-Air Impacts" for the CBT upgrades?

   Clean burn technology control employs a combustion mixture with a higher air-to-fuel ratio, because using fuel-lean mixtures lowers the combustion temperature by diluting energy input. This could reduce NO_X emissions; however, a reduction in combustion temperature also tends to increase emissions of CO due to incomplete combustion [Solar Turbines, "Developments in Dry Low Emissions Technology", 2006].

5. While not an issue here necessarily, I think your GHG Emissions Inventory calculations (e.g. for CO2 tpy, "=D51*B12/2000") is incorrect, with a cell reference to B-12 (i.e. "Maximum hp") instead of B-11 (i.e. "Hours of Operation").

   Thank you for your note. This will be updated for future Inventory calculations.

Thank you for your help on this,

Neal

IACX Bitter Lake Compressor Station

Amortization of equipment		
NMED Assumed Discount Rate - "r"		3.25%
Life Expectancy of control equip (years) - "n"		20

Cooper-Bessemer / GMVH-10C 2SLB RICE; Unit C-891			
Equipment, install labor and materials for Turbocharger and Intercooler Upgrades	$	383,482	<-- Cooper estimated
Existing Materials Upgrades (Oil Cooler and Supplemental Water-Cooling System)	$	204,186	<-- Cooper estimated
Additional Equipment Upgrades Recommended (Modern Generation Jet Cell with ePCC System)	$	98,832	<-- Cooper estimated
Permitting Cost	$	15,000	<-- Trinity estimated (includes estimated cost of labor and review fee)
Total Cap Investment - "P"	**$**	**701,500**	
Annualized TCI - "A"	$	48,248	<-- Based on interest rate, year and TCI per NMED calculation methodology
Annual O&M Costs:	$	174,750	<-- Trinity estimated; engine maintenance and labor costs, based on similar units *($75/BHP engine maintenance cost, 100 labor hours/yr at 60 $/hr)*
Total Annual Costs	**$**	**222,998**	
Baseline NOx Emissions (tpy)		**39.62**	<-- from 2019 Emissions Inventory submissions - AEIR
Estimated Controlled Emissions (tpy)		**23.70**	<-- Based on 2 g/hp-hr emission standard guarantee from Cooper
Emission Reduction (tpy)		**15.93**	
Engine Upgrades Cost: $/yr-ton	**$**	**14,002**	

Cooper-Bessemer / GMVH-10C 2SLB RICE; Unit C-893			
Equipment, install labor and materials for Turbocharger and Intercooler Upgrades	$	383,482	<-- Cooper estimated
Existing Materials Upgrades (Oil Cooler and Supplemental Water-Cooling System)	$	204,186	<-- Cooper estimated
Additional Equipment Upgrades Recommended (Modern Generation Jet Cell with ePCC System)	$	98,832	<-- Cooper estimated
Permitting Cost	$	15,000	<-- Trinity estimated (includes estimated cost of labor and review fee)
Total Cap Investment - "P"	**$**	**701,500**	
Annualized TCI - "A"	$	48,248	<-- Based on interest rate, year and TCI per NMED calculation methodology
Annual O&M Costs:	$	174,750	<-- Trinity estimated; engine maintenance and labor costs, based on similar units *($75/BHP engine maintenance cost, 100 labor hours/yr at 60 $/hr)*
Total Annual Costs	**$**	**222,998**	
Baseline NOx Emissions (tpy)		**21.75**	<-- from 2019 Emissions Inventory submissions - AEIR
Estimated Controlled Emissions (tpy)		**22.73**	<-- Based on 2 g/hp-hr emission standard guarantee from Cooper
Emission Reduction (tpy)		**0.00**	(2018 stack test recorded emissions less than Cooper guarantee. No anticipated reduction possible.)
Engine Upgrades Cost: $/yr-ton	**$**	**222,998**	

D.10 Oxy USA WTP Limited Partnership

Supporting documentation for Oxy USA WTP Limited Partnership is provided below. Facility-specific documentation is provided first, followed by documentation pertaining to multiple facilities and/or the owner/operator. The following documents are included in this section (in reading order):

- Indian Basin Gas Plant:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (10/31/2019)
    - Follow-Up Submittal (2/2020)
    - Follow-Up Submittal (10/21/2020)
    - Follow-Up Submittal (7/21/2023)
    - Follow-Up Submittal (8/14/2023)

NMED Final Cost Evaluation
Oxy USA WTP Limited Partnership - Indian Basin Gas Plant

Facility Information

Oxy Indian Basin Gas Plant	**Facility**
Three 1980 Solar Centaur CTs (4002/4702)	**Units**
ES-06/07, ES-08/09 and ES-10/11	**Unit IDs**
SoLoNOx	**Evaluated Pollution Control**
25	**Post-control Emissions Rate (ppmvd NOx)**

Supporting Information

2023	**Calendar year associated with cost estimates**
4000	**Maximum/Permitted Power Output (hp/unit) (ES-06-07 and ES-08/09)**
4700	**Maximum/Permitted Power Output (hp/unit) (ES-10/11)**

Economic Evaluation

Cost Component		ES-06/07	ES-08/09	ES-10/11	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	Included in TCC
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	Included in TCC
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	Included in TCC
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	Included in TCC
Total Capital Costs - Direct ($)	TCC	$ 1,779,200	$ 1,779,200	$ 1,779,200	Oxy 2019 FFA Submittal (2017$ converted to 2023$ using CEPCI)	Based on a SoloNox retrofit for a similar unit installed at the facility.
Additional Capital ($)	AC	$ 198,000	$ 198,000	$ -	Oxy 2019 FFA Submittal (2018$ converted to 2023$ using CEPCI)	Additional cost to uprate unit (not required for ES-10/11)
Total Capital Investment ($)	TCI	$ 1,977,200	$ 1,977,200	$ 1,779,200	-	TCI + AC
Interest Rate (%)	R	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	Oxy did not provide a company-specific rate
Useful Life (yr)	Y	20	20	20	Manufacturer	Consistent with other FFAs
Capital Recovery Factor	CRF	0.0981	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 193,948	$ 193,948	$ 174,526	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 40,137	$ 40,137	$ 44,169	Oxy 2019 FFA Submittal (2018$ converted to 2023$ using CEPCI)	Incremental maintenance and overhaul costs
Other Indirect Annual Costs ($/yr)	OAC	$ 79,088	$ 79,088	$ 71,168	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 313,173	$ 313,173	$ 289,862	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	74%	74%	67%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	49.3	47.3	43.4	CY 2019 emissions testing and average operating hours (2016-2019)	Assumed 8760 hours for ES-10/11 due to insufficient operating data
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Oxy
Projected Actual Emissions (ton/yr)	PAE	49.3	47.3	43.4	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	36.5	35.0	29.0	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 8,577**	**$ 8,945**	**$ 10,010**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January - September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 8,577**	**$ 8,945**	**$ 10,010**	-	CE1 x PI

NMED Final Cost Evaluation
Oxy USA WTP Limited Partnership - Indian Basin Gas Plant

Facility Information

Oxy Indian Basin Gas Plant	**Facility**
Three 1980 Solar Centaur CTs (4002/4702)	**Units**
ES-06/07, ES-08/09 and ES-10/11	**Unit IDs**
SCR	**Evaluated Pollution Control**

Supporting Information

2024	**Calendar year associated with cost estimates**
4000	**Maximum/Permitted Power Output (hp/unit) (ES-06-07 and ES-08/09)**
4700	**Maximum/Permitted Power Output (hp/unit) (ES-10/11)**

Economic Evaluation

Cost Component		ES-06/07	ES-08/09	ES-10/11	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -		-	TCI likely underestimates total costs; does not include construction and engineering costs needed to create physical space. Oxy indicated that there is insufficient power available to support SCR but did not provide a cost estimate for upgrades to the electric substation and distribution lines. As a result, NMED included a $5M infrastructure cost estimate in additional capital (apportioned among all three units). This value is believed to underestimate the likely cost based on information provided by other facilities.
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -		-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -		-	
Indirect Capital Costs ($)	IDC	$ -	$ -		-	
Total Capital Costs - Direct ($)	TCC	$ 2,571,739	$ 2,571,739	$ 2,572,168	EPA SCR Tool (2024$)	
Additional Capital ($)	AC	$ 1,666,667	$ 1,666,667	$ 1,666,667	See Note	
Total Capital Investment ($)	TCI	$ 4,238,406	$ 4,238,406	$ 4,238,835	-	TCC + AC
Interest Rate (%)	R	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	Oxy did not provide a company-specific rate
Useful Life (yr)	Y	20	20	20	Default per EPA Cost Manual	
Capital Recovery Factor	CRF	0.0981	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 415,755	$ 415,755	$ 415,797	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 39,863	$ 38,920	$ 43,619	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 2,782	$ 2,782	$ 2,782	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 458,400	$ 457,457	$ 462,198	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	80%	80%	80%	EPA SCR Tool	Consistent with EPA and industry documentation.
Baseline Actual NOx Emissions (ton/yr)	BAE	49.3	47.3	43.4	CY 2019 emissions testing and average operating hours (2016-2019)	Assumed 8760 hours for ES-10/11 due to insufficient operating data
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Oxy
Projected Actual Emissions (ton/yr)	PAE	49.3	47.3	43.4	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	39.5	37.8	34.8	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 11,613**	**$ 12,087**	**$ 13,298**	-	TAC/ER

NMED Final Cost Evaluation
Oxy USA WTP Limited Partnership - Indian Basin Gas Plant

Facility Information

Oxy Indian Basin Gas Plant	**Facility**
Three 1980 Solar Centaur CTs (4002/4702)	**Units**
ES-06/07, ES-08/09 and ES-10/11	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
15.0	**Post-control Emissions Rate (ppmvd @ 15% O2)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired CT >=4,000 hp and <15,900 hp.

Additional Information

2023	**Calendar year associated with cost estimates**
4000	**Maximum/Permitted Power Output (hp/unit) (ES-06-07 and ES-08/09)**
4700	**Maximum/Permitted Power Output (hp/unit) (ES-10/11)**

Economic Evaluation

Cost Component		ES-06/07	ES-08/09	ES-10/11	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 12,960,480	$ 12,960,480	$ 15,228,564	9/8/20 info from El Paso Natural Gas (2020$ converted to 2023$ using CEPCI)	All-in estimate ($/HP) x Maximum Capacity (HP); Using EPNG's $2418/hp cost metric as Oxy did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered CT.
Interest Rate (%)	R	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	Oxy did not provide a company-specific rate
Useful Life (yr)	Y	30	30	30	ERG experience based on discussions with CT manufacturers	
Capital Recovery Factor	CRF	0.0847	0.0847	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 1,097,380	$ 1,097,380	$ 1,289,421	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 40,137	$ 40,137	$ 44,169	Oxy 2019 FFA Submittal (2018$ converted to 2023$ using CEPCI)	Assumed equal to incremental SoloNOx O&M. Reasonably consistent with information provided by other facilities.
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 1,137,517	$ 1,137,517	$ 1,333,590	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	84%	84%	80%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	49.3	47.3	43.4	CY 2019 emissions testing and average operating hours (2016-2019)	Assumed 8760 hours for ES-10/11 due to insufficient operating data
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Oxy
Projected Actual Emissions (ton/yr)	PAE	49.3	47.3	43.4	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	41.6	39.9	34.8	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 27,315**	**$ 28,488**	**$ 38,373**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January - September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 27,315**	**$ 28,488**	**$ 38,373**	-	CE1 x PI

NMED Final Cost Evaluation
Oxy USA WTP Limited Partnership - Indian Basin Gas Plant

Facility Information

Oxy Indian Basin Gas Plant	**Facility**
Three 1980 Solar Centaur CTs (4002/4702)	**Units**
ES-06/07, ES-08/09 and ES-10/11	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Target Emissions Rate (lb/hr)**

Additional Information

2023	**Calendar year associated with cost estimates**
12700	**Total Power Capacity (all units)**

Economic Evaluation

Cost Component		All Units	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -		Oxy did not provide an estimate for electrification. As a result, the TCC of an EMD unit is based on a cost metric of 2,084 $/hp installed (2023$) derived from cost estimates provided by other facilities. Oxy indicated that there is insufficient power available to support additional electrical demands at the facility, but did not provide a cost estimate for upgrades to the electric substation and distribution lines. As a result, NMED included a $5M infrastructure cost estimate. This value is believed to underestimate the respective cost based on information provided by other facilities.
Other Direct Capital Costs 1 ($)	ODC1	$ -		
Other Direct Capital Costs 2 ($)	ODC2	$ -		
Indirect Capital Costs ($)	IDC	$ -		
Total Capital Costs - Direct ($)	TCC	$ 26,466,800	See Note	
Additional Capital ($)	AC	$ 5,000,000	See Note	
Total Capital Investment ($)	TCI	$ 31,466,800	-	TCC + AC
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	Oxy did not provide a company-specific rate
Useful Life (yr)	Y	25	Other FFAs	
Capital Recovery Factor	CRF	0.090	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 2,822,908	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 1,571,911	-	AED + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 3,143,822	Engineering judgement	Assumes 60% load, 95% efficiency, and $0.06/kWh price
Associated non-electricity O&M ($/yr)	AOM	$ -	-	Not provided by Oxy; Assumed that O&M costs offset
Annual Fuel Credit ($/yr)	AFC	$ (1,571,911)	ERG Calculation	Assumes fuel savings is 50% of AED
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 4,394,819	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	140.1	CY 2019 emissions testing and average operating hours (2016-2019)	BAE of both units
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by Oxy
Projected Actual Emissions (ton/yr)	PAE	140.1	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	140.1	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 31,371**	-	TAC/ER
Price Index	PI	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January - September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 31,371**	-	CE1 x PI

NMED Final Cost Evaluation
Oxy USA WTP Limited Partnership - Indian Basin Gas Plant

Facility Information

Oxy USA - Indian Basin	**Facility**
ATS	**Units**
Addition of new EMD for redundant compression	**Evaluated Pollution Control**
90%	**Estimated reduction in AGI SSM/M flaring emissions**

Supporting Information

2018	**Calendar year associated with cost estimates**

Economic Evaluation

Cost Component		ATS	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 1,968,750	Targa SEP Proposal	Targa's $11M TCI estimate was not supported by documentation. The cost estimate provided with Targa's SEP proposal for EMD redundant compression was detailed and included PEC, sales tax, freight, foundations, piping, instrumentation, installation, electrical tie-ins, engineering. This information is used as a conservative - i.e., low - TCI estimate given that the corresponding Targa compression capacity and flare are significantly smaller than this facility's.
Other Direct Capital Costs 1 ($)	ODC1	$ 1,050,000	Targa SEP Proposal	
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	
Indirect Capital Costs ($)	IDC	$ 98,438	Targa SEP Proposal	
Total Capital Costs - Direct ($)	TCC	$ 3,117,188	-	PEC + ODC1 + ODC2 + IDC
Additional Capital ($)	AC	$ -	-	
Total Capital Investment ($)	TCI	$ 3,117,188	-	TCC + AC
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	Oxy did not provide a company-specific rate
Useful Life (yr)	Y	20	Oxy FFA submittal (2019)	Since the unit will be operating in acid gas service, the life span of the compressor will not be longer than 20 years.
Capital Recovery Factor	CRF	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 305,772	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 120,000	Oxy FFA submittal (2019)	
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit.
Total Annualized Costs ($/yr)	TAC	$ 425,772	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	90%	Oxy FFA submittal (2019)	Estimated 90% reduction in flaring emissions
Baseline Actual NOx Emissions (ton/yr)	BAE	24.6	Average reported emissions from flaring and SSM (2016-2019)	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by Oxy
Projected Actual Emissions (ton/yr)	PAE	24.6	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	22.1	-	Estimated 90% reduction in flaring emissions
2018$ Cost Effectiveness ($/ton)	**CE1**	**$ 19,262**	-	TAC/ER; SEP proposal is dated 12/27/18, so assume estimated costs are in 2018$
Price Index	PI	1.32	-	2024 CEPCI* / 2018 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 25,426**	-	CE1 x PI

Unit ES-06/07: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	39	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	252,573,230	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3821	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.3790	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0758	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

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Unit ES-06/07: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	39	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	331,367,604	scf/Year	
Actual Annual fuel consumption (Mactual) =		252,573,230	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.762	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6677	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	11.82	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	39.47	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.15		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	156.30	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole
Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	5	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	16	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	800	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	23.09	kW

Unit ES-06/07: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,571,739	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$39,863 in 2024 dollars
Indirect Annual Costs (IDAC) =	$255,070 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$294,933 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,859 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$7,476 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$15,416 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$4,112 in 2024 dollars
Direct Annual Cost =		$39,863 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,782 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$252,288 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$255,070 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$294,933 per year in 2024 dollars
NOx Removed =	39 tons/year
Cost Effectiveness =	$7,472 per ton of NOx removed in 2024 dollars

Unit ES-08/09: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	39	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	242,170,708	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3821	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.3790	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0758	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

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Unit ES-08/09: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	39	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	331,367,604	scf/Year
Actual Annual fuel consumption (Mactual) =		242,170,708	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.731	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6402	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	11.82	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	37.85	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.15	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	156.30	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole
Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	5	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	16	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	800	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	23.09	kW

Unit ES-08/09: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,571,739	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$38,920 in 2024 dollars
Indirect Annual Costs (IDAC) =	$255,070 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$293,990 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,859 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$7,169 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$14,781 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$4,112 in 2024 dollars
Direct Annual Cost =		$38,920 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,782 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$252,288 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$255,070 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$293,990 per year in 2024 dollars
NOx Removed =	38 tons/year
Cost Effectiveness =	$7,768 per ton of NOx removed in 2024 dollars

NMED Final Cost Evaluation
Oxy USA WTP Limited Partnership - Indian Basin Gas Plant

Unit ES-10/11: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	39.01	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	331,452,570	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3821	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.2543	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0509	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours	
Estimated SCR equipment life	20	Years*	

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F	*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour	

Concentration of reagent as stored (C_{stored})	29	percent*	
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*	
Number of days reagent is stored ($t_{storage}$)	14	days	

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

NMED Final Cost Evaluation
Oxy USA WTP Limited Partnership - Indian Basin Gas Plant

Unit ES-10/11: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	39	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	331,452,570	scf/Year	
Actual Annual fuel consumption (Mactual) =		331,452,570	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	7.94	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	34.76	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.15		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	149.92	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole
Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	3	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	11	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	1	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	500	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	23.09	kW

Unit ES-10/11: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,572,168	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$43,619 in 2024 dollars
Indirect Annual Costs (IDAC) =	$255,112 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$298,731 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$12,861 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$6,584 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$20,231 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$3,944 in 2024 dollars
Direct Annual Cost =		$43,619 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,782 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$252,330 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$255,112 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$298,731 per year in 2024 dollars
NOx Removed =	35 tons/year
Cost Effectiveness =	$8,594 per ton of NOx removed in 2024 dollars

OXY USA WTP Limited Partnership
A subsidiary of Occidental Petroleum Corporation

5 Greenway Plaza, Suite 110, Houston, Texas 77046-0521
Direct Phone: 713-215-7000

October 31, 2019

FEDEX

Mr. Kerwin Singleton
NMED Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505

Re: Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program- OXY USA WTP Limited Partnership (OXY); Indian Basin Gas Plant

Dear Mr. Singleton:

OXY USA WTP Limited Partnership (OXY) is submitting this Four-Factor Analysis Report per request of the New Mexico Environment Department in the letter dated July 18, 2019. The Indian Basin Gas Plant Four-Factor Analysis is attached to this letter.

This submittal includes one hard copy and one electronic copy. Please feel free to contact me at (713) 366-5331 if you have any questions regarding this analysis.

Sincerely,

Femi Serrano
Environmental Advisor Sr.
OXY USA WTP Limited Partnership

Cc: Jane Romero Kotovsky (Trinity Consultants Inc.).

REGIONAL HAZE FOUR-FACTOR ANALYSIS

OXY USA WTP Limited Partnership
Indian Basin Gas Plant

Prepared By:

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November 2019

Project 193201.0195

Trinity Consultants

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1. EXECUTIVE SUMMARY

In the 1977 amendments to the Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across the United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

> *(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A).*
>
> This is known as a four-factor analysis.
>
> *(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B).*
>
> The uniform rate of progress or improvement is sometimes referred to as the glide path and is part of the state's Long Term Strategy (LTS).

The second implementation planning period (2018-2028) for national regional haze efforts is currently underway. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural or biogenic and manmade or anthropogenic sources of emissions. Using a Photochemical Grid Model (PGM), the Western Regional Air Partnership (WRAP), in coordination with the EPA, is tasked with comparing anthropogenic source contributions against natural background concentrations.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for major sources and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I area. From this analysis, 24 facilities were identified by the NMED. On July 18, 2019 the NMED informed OXY USA WTP Limited Partnership (OXY) that its Indian Basin Gas Plant (IBGP) facility was identified as one of the sources contributing to regional haze at the Carlsbad Caverns National Park Class I area.

In coordination with WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. In the NMED's July 18, 2019 notification letter to OXY, it specifies that any equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The subject equipment at IBGP, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant are reported in Table 1.

Table 1. Summary of Equipment and Applicability to a Four-Factor Analysis

Equipment	NO_X Hourly PTE (lb/hr)	NO_X Annual PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
Natural Gas-Fired Simple Cycle Turbines (Units ES-06/07 & ES-08/09)	15.5	67.9	Yes	0.029	0.13	No
Natural Gas-Fired Simple Cycle Turbine (Unit ES-10/11)	23.7	104	Yes	0.029	0.13	No
Amine Gas Treating Units (Unit AMINE-1 & SELEXOL)[a]	-	-	No	-	-	Yes

[a] This unit is controlled by an acid gas injection well and flare. No emissions from this unit vent directly to the atmosphere.

Once the applicability of equipment and pollutants has been determined, potential retrofit control technologies must be identified. In accordance with 40 CFR 51 Appendix Y and at the recommendation of the NMED[1], this is primarily achieved by utilizing the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) data. In order to determine the most relevant and current retrofit controls available, the RBLC is queried for the previous ten years. Summaries of the result of this search are provided and discussed under Section 2 of this report. OXY engineers then reviewed the list of available retrofit technologies and performed a technical feasibility assessment for each control option. The four-factor analysis is then conducted for those controls that are technically feasible.

[1] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

NO_X is the only pollutant subject to evaluation in this four-factor analysis for the three turbines. The turbines, Unit ES-06/07 and Unit ES-08/09, are Solar model Centaur 40-4002 natural gas-fired, simple cycle turbines. Turbine Unit ES-10/11 is a Solar model Centaur 40-4702 natural gas-fired, simple cycle turbine. Units ES-06/07 and ES-08/09 are rated at 4,000 horsepower and were manufactured in 1980. Unit ES-10/11 is rated at 4,700 horsepower and was manufactured in 1980.

SO_2 is the only pollutant subject to the evaluation in this four-factor analysis for the two amine units. The amine units, AMINE-1 and SELEXOL, are both currently controlled by an acid gas injection well and an acid gas flare.

2.1. COMBUSTION TURBINES

2.1.1. Combustion Turbine Background

A gas turbine is an internal combustion engine that operates with a rotary, rather than reciprocating, motion and is composed of three primary components: a compressor, a combustor, and a power turbine. The compressor draws in ambient air and compresses it up to 30 times the ambient pressure, then directs it into the combustor where fuel is introduced, ignited, and burned. Exhaust gas from the combustor is then diluted with additional air and sent to the power turbine at temperatures up to 2600 °F. The hot exhaust gas expands in the power turbine section, generating energy in the form of shaft horsepower.[2]

The treatment of the exhaust gases exiting the turbine dictate the cycle designation of these units. The heat content can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).[3] The units at IBGP are simple cycle turbines.

NO_X is formed via three fundamentally different mechanisms. The principle NO_X formation mechanism, thermal NO_X, arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion. Most thermal NO_X forms in the highest temperature regions of the combustion chamber. The second NO_X formation mechanism, fuel NO_X, arises from the evolution and reaction of fuel bound nitrogen compounds with oxygen. The final NO_X formation mechanism, prompt NO_X, arises from early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The significance of prompt NO_X is negligible in comparison to thermal and fuel NO_X. Fuel NO_X will also be negligible for IBGP's turbines assessed here, as these combustion turbines fire natural gas, which contains a negligible amount of nitrogen compounds. Therefore, this analysis will focus on thermal NO_X.

The PTE from each turbine is reported in the facility's New Source Review (PSD0295M11) and Title V (P103R2) permits, as well as summarized in Table 1 of this report.

[2] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"
[3] Ibid.

2.1.2. Potential NO_X Controls for a Combustion Turbines

There are three general methods of controlling NO_X emission from gas turbines; (1) wet controls, which use steam or water injection to reduce combustion temperatures and NO_X formation, (2) dry controls that use advanced combustor design to suppress NO_X formation, and (3) post-combustion, catalytic controls to selectively reduce NO_X.[4]

The retrofit control equipment that was identified for combustion turbines during a comprehensive review of the RBLC, available literature, and manufacturer's input is reported in Table 2. A more detailed table summarizing the RBLC review is provided in Appendix A. A detailed discussion, including a description, the technical feasibility, and the anticipated performance of each control is provided below.

Table 2. Potential Control Options for Combustion Turbines

Control Equipment	Technically Feasible for 4002 (Units ES-06/07 & ES-08/09)?	Technically Feasible for 4702 (Units ES-10/11)?	NO_X Control Efficiency
Good Combustion Practices	Yes	Yes	Base Case
Improved Combustion Technology	Yes	Yes	25 ppm
Water Injection	No	No	60%
Selective Catalytic Reduction	No	No	25 ppm

2.1.2.1. Good Combustion Practices

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from combustion turbines; therefore, it has been determined that this method of NO_X control is feasible for the units at IBGP. However, these practices are currently in use at IBGP, as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices is included in this report.

2.1.2.2. Improved Combustion Technology

The improved combustion technology control option, commonly referred to as Dry Low NO_X (DLN) control, seeks to reduce the conversion of atmospheric nitrogen to NO_X by reducing the combustion temperature and residence time of fuel in the combustor. There are several levels of improvements that can be made to the combustion chamber, which achieve this NO_X control at varying levels. The improved combustion technology available for the units at IBGP is produced by the manufacturer of the units, Solar, and is called SoLoNO_X.

[4] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"

SoLoNO$_X$ utilizes lean-premixed combustion technology to ensure an extremely uniform air/fuel mixture and stringently controls the combustion process to prevent excess NO$_X$ emissions from forming.

Based on communication with Solar, SoLoNO$_X$ is available for both the 4002 (Units ES-06/07 and ES-08/09) and 4702 (Unit ES-10/11) Solar turbines located onsite. However, in order to support the technology each of the 4002 units would need to be uprated to model 4702, respectively, because installation of SoLoNO$_X$ requires the turbine combustors to be capable of handling significantly higher temperatures. Uprating the units involves completely replacing the combustor section of the turbine with a much larger and more robust combustor.

Improved combustion technology was identified in this review of RBLC as a potential control of NO$_X$ emissions from natural gas-fired combustion turbines, and AP-42 Section 3.1 also lists this as an available control technique for gas turbines.[5] Therefore, it has been determined that this control technology is technically feasible for the turbines located at IBGP. Solar can guarantee output NO$_X$ emissions of 25 parts per million (ppm) for units with SoloNO$_X$ installed.

2.1.2.3. Water Injection

Water injection is a control technology for gas turbines that has been demonstrated to effectively suppress NO$_X$ emissions. Injection of water has the effect of increasing the thermal mass by dilution and thereby reducing the peak temperature in the flame zone. There is an additional benefit of absorbing the latent heat of vaporization from the flame zone when water injection is utilized. Water is typically injected at a water-to-fuel weight ratio of less than one.[6] Steam injection is not discussed as an option since Solar does not manufacture turbines with steam injection technology.

The capability of these units to be retrofit for water injection is dependent on the make and model of the turbine, per communications with Solar. Solar has indicated that the turbine models at IBGP are unable to be retrofitted with water injection; Therefore it has been determined that water injection control is technically infeasible for the Solar turbines located at IBGP (Units ES-06/07, ES-08/09, and ES-10/11).

2.1.2.4. Selective Catalytic Reduction Systems

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO$_X$ in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[7] The chemical reactions for this process are shown in the equations below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

An SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and an electronic control system. The electronic controls regulate the quantity of reagent injected as a function of turbine load, speed, and temperature, so NO$_X$ emissions reductions can be achieved. The lifespan of the catalyst is primarily determined by poisoning of active sites by flue gas constituent, thermal

[5] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"
[6] Ibid.
[7] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

sintering, or compacting, of active sited due to high temperatures in the reactor, fouling caused by ammonia-sulfur salts and particulate matter in the gas, and erosion due to high gas velocities.[8]

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as ammonia slip. Unreacted ammonia in the exhaust can form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams can blind the catalyst and may necessitate the application of a soot blower.[9]

In order for an SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 and 850 °F), dependent on the material of the catalyst. Exhaust gas temperatures greater than the upper limit will cause the NO_X and ammonia to pass through the catalyst unreacted.[10] Communication with Solar has indicated that SCR controls are available for each of the turbine models assessed here but the facility engineers have determined the additional power demands required to install SCR controls on the turbines are infeasible. The power at the plant would need to be upgraded significantly and re-designed in order to power the SCR controls. Therefore, SCR is considered a technically infeasible control option for the turbines located at IBGP and are not assessed further in this report.

2.2. AMINE TREATING UNITS

2.2.1. Amine Treating Unit Background

Concentrations of H_2S or CO_2 are unfavorable in natural gas since they both can form a corrosive acid when in the presence of water.[11] H_2S is also highly toxic. Gas processing plants use amine treating units to remove H_2S and CO_2 from natural gas since amines such as Monoethanolamine (MEA), Diglycolamine (DGA), Diethanolamine (DEA) and Methyldiethanolamine (MDEA) are able to form salts with H_2S and CO_2 in an aqueous solutions.

An amine treating unit operates by feeding natural gas into the bottom of a contactor and simultaneously feeding a lean amine solution at the top of the contactor. The two streams interact in the counter flow, resulting in CO_2 and H_2S being stripped from the natural gas stream. The lean amine solution must be kept at a higher temperature than the gas feeding into the contactor, or condensation of heavier hydrocarbons could occur.[12] Trays or packing along the contactor walls provide a place for the lean amine solution to interact with the natural gas. The natural gas leaving the contactor will be "sweet gas."[13]

The rich amine leaving the contactor is usually sent to a flash tank which reduces the pressure of the stream and causes dissolved hydrocarbons to be removed.[14] The rich amine will then pass through a heat exchanger and enter a solvent regenerator. The heated vapor generated at the bottom of the regenerator flows upward through the trays or packing where it comes in contact with the rich amine and removes the acid gases from the amine. The lean amine is then cooled and reenters the first contactor to start the process over. The acid gas that is

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[8] Ibid.
[9] Ibid.
[10] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"

[11] KIDNAY, A. J.; PARRISH, W. R.; MCCARTNEY, D. G. Fundamentals of natural gas processing. CRC Press, 2011;

[12] Ibid

[13] Ibid

[14] Ibid

dissolved in the vapor is then sent to a control device such as a sulfur recover unit with a tail gas incinerator, a flare, or an acid gas injection (AGI) well.

2.2.2. Potential SO_2 Controls for an Amine Treater

As listed above, potential controls for amine treating systems are a sulfur recovery unit with a tail gas incinerator, a flare, or an AGI well. In addition, the aforementioned controls will also have an associated acid gas flare as a standby control device when the main controls are being maintenanced. Sulfur recovery units are not discussed in this report since the facility has an AGI well installed.

2.2.2.1. Acid Gas Flare

Acid gas flares can be used as a backup control to sulfur recovery units with tail gas incinerators or acid gas injection (AGI) wells or they can be a main control for an amine system. Acid Gas flares are used to destroy H_2S emissions by converting H_2S to SO_2 during the combustion process. For a flare to operate properly, a heat content of 300 BTUs per standard cubic feet must be met. When this heat content is met, a flare will have at least a 98% control efficiency.[15] Since acid gas can have a very low heat content (less than 300 BTU per standard cubic feet), assist gas may be added to the stream to increase the heat content over this threshold. At gas plants, assist gas usually consists of mixing the acid gas stream with the residue gas from the facility.

IBGP currently operates an acid gas flare that operates when the AGI well is down for maintenance. Please see Section 2.2.2.2 for information on the acid gas injection well operation at the facility.

2.2.2.2. Acid Gas Injection Well

An AGI well will necessitate a geological study to be completed in order to determine if there are carbonate or sandstone reservoirs deep underground that can store the acid gas. If there is such a geological formation near the facility that will support the injection of acid gas, an AGI well can be drilled. An electrically driven compressor will pressurize the acid gas and pump it into the well to be stored in the underground reservoir. When the AGI well is operating there are no emissions vented to the atmosphere except for a fugitive emissions since all emissions are stored underground.

IBGP currently operates an AGI well to control amine emissions at the facility. To further improve the control of amine units at the facility, a redundant acid gas electrically driven compressor can be added to the AGI well system. This will reduce flaring emissions at the facility by having less downtime from performing maintenance on the acid gas compressor. This is the only additional control the facility can employ to reduce SO_2 emissions further.

[15] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Flare)," EPA-452/F-03-019.

OXY has evaluated the costs of implementing the technologically feasible control technologies as thoroughly as possible in the time provided to complete this assessment. These cost estimates are calculated according to the methods and recommendations in the EPA Air Pollution Control Cost Manual.[16] Cost effectiveness considerations for each unit and control technology are discussed below.

3.1. COMBUSTION TURBINES

Cost effectiveness for each combustion turbine control option are summarized Table 3.

Table 3. Cost Analysis Summary of Technically Feasible Control Options for Combustion Turbines at IBGP

Control Equipment	Unit	Capital Cost ($)	Total Annual Cost ($)*	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Improved Combustion Technology	ES-06/07	$1.51 M	$156.8 K	41.16	$3.81 K
	ES-08/09	$1.51 M	$156.8 K	37.94	$4.13 K
	ES-10/11	$1.36 M	$147.2 K	80.33	$1.83 K

*Total Annual Cost includes the annualized capital cost, as well as the direct and indirect annual operating costs.

3.1.1. Improved Combustion Technology

The equipment and installation labor cost discussed in this section was based on vendor data received for a similar replacement unit from Solar. The EPA Air Pollution Control Cost Spreadsheet was used to estimate all other costs completed in this section. The NO_X emissions are based on an outlet concentration of 25ppm. The costs are shown in Table 3 above. These cost estimates have been developed based on the actual emissions from each unit using the 2016 Emission Inventory submittal for IBGP. The full cost estimation for each unit is included in Appendix B of this report.

Please note that unit ES-10/11 was uprated in 2018 and the emissions for the unit increased. Per communication with the NMED, the actual emissions for calculating cost effectiveness should be based on 2016 actual emissions. Since the emissions for ES-10/11 were changed after the 2016 baseline date, PTE emissions along with a recent stack test were used to calculate the cost effectiveness of the unit.

[16] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

3.2. AMINE TREATING UNITS

Cost effectiveness for the redundant electric compression control is summarized in Table 4.

Table 4. Cost Analysis Summary of Technically Feasible Control Options for Engines at IBGP

Control Equipment	Capital Cost ($)	Total Annual Cost ($)*	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Redundant Compression	$11.0 M	$1.04 M	37.7	$27.6 K

*Total Annual Cost includes the annualized capital cost, as well as the direct and indirect annual operating costs.

3.2.1. Redundant Compression

OXY obtained a total cost estimate for installing redundant electric compression associated with the AGI well. The estimate incorporates direct capital cost for equipment and vendor labor, indirect costs associated with OXY's internal labor, and overhead and contingency costs for the project. According to this estimate, the redundant compressor would cost $11 M with $120 K per year for operating costs. The addition of this unit will reduce SO_2 emissions by 90% resulting in an emission rate reduction of 37.7 tpy. Emission effectiveness is therefore expected to be approximately $27.6 K per ton of reduced emissions. These cost estimates have been developed based on the actual emissions from each unit assessed here, using the 2016 Emission Inventory submittal for IBGP. The full cost estimation for each unit is included in Appendix B of this report.

4. TIME NECESSARY FOR COMPLIANCE

The second factor in this analysis is the time necessary for compliance. Consideration of this factor involves estimating the time required for a source to implement a potential control measure. This information is provided here in order to advise the NMED of OXY's projection of a reasonable compliance timeline based on the equipment and site-specific considerations that could affect the time necessary to comply.

4.1. COMBUSTION TURBINES

4.1.1. Improved Combustion Technology

OXY estimates that approximately 4-5 years will be needed to implement the improved combustion technology control equipment. Factors that have been considered for this anticipated timeline include permitting, budgeting, design, uprating the combustors, procuring the equipment, and installation of the control.

4.2. AMINE TREATING UNIT

4.2.1. Redundant Electric Compression

OXY estimates that approximately 5 years will be needed to budget, design, procure, and construct the redundant compressor. Factors that have been considered for this anticipated timeline include permitting, budgeting, design, procuring the equipment, and installation of the control.

5. ENERGY AND NON-AIR ENVIRONMENTAL IMPACTS

This section addresses the potential energy and non-air environmental impacts that installation of the technically feasible control options pose on a source. The consideration of energy impacts involves assessing the impact of a control measure on the energy that is consumed by the source. Non-air environmental impacts are assessed based on the effect of the control on non-air environmental media. Some examples of non-air environmental impacts include water resource depletion, solid waste generation, increased noise and odor pollution, and increased land usage.

5.1. COMBUSTION TURBINES

5.1.1. Improved Combustion Technology

It is not anticipated that installation of the improved combustion technology SoLoNO$_X$ on the turbines at IBGP will have any significant energy or non-air environmental impacts.

5.2. AMINE TREATING UNIT

5.2.1. Redundant Compression

There are no anticipated unique or site-specific energy or non-air impacts imposed by the installation of the redundant compression.

6. REMAINING USEFUL LIFE OF SOURCES

The anticipated remaining useful life of each source is addressed here for the NMED's consideration. The assessment of this factor involves estimating how long the sources analyzed will remain in operation and the lifetime of potential control measures, accounting for equipment and site-specific limitations.

40 CFR Part 51, Appendix Y includes guidance on the characterization of this factor, stating that the remaining useful life of a source will typically be longer than the useful life of the emission control system. Therefore, it is appropriate to annualize compliance costs based on the useful life of the control equipment, rather than the life of the source.[17]

6.1. COMBUSTION TURBINES

Based on their current age and operating efficiency, it is estimated that the remaining useful life of the turbines will be longer than the control units. Two of the turbines have operated for more than 35 years without any significant deterioration in operating efficiency and one of the turbines was installed in the last year; therefore, this analysis of the remaining useful life of the equipment will be based on the anticipated useful life of the control device considered.

6.1.1. Improved Combustion Technology

It is anticipated that the estimated useful life of the improved combustion technology, SoLoNO$_X$, will be similar to the useful life of an SCR system. The useful life is estimated to be 20 years, based on default values from the EPA Air Pollution Control Cost Manual.[18]

6.2. AMINE TREATING CONTROL

6.2.1. Redundant Compression

The estimated useful life of the redundant compressor is about 20 years. Since the unit will be operating in acid gas service, the life span of the compressor will not be longer than 20 years.

[17] 40 CFR 51, Appendix Y, Section II.B.4.f

[18] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

7. SUMMARY & CONCLUSIONS

Based on a comprehensive review of the RBLC, available literature, and manufacturer's input of the available control technologies for the natural-gas fired turbines, OXY has determined that the SoloNOx controls are the only technically feasible control option for the turbines under review in this analysis. The marginal reduction in NO_X emissions to install the SoLoNOx controls on each of these units does not support the high investment cost of the control. The only option to further control SO_2 emissions from the amine systems would be to install redundant electric compression to support the AGI well. There is an extremely high initial investment cost to add this compression due to infrastructure changes needed in order to complete the modification. With such a high investment cost, OXY believes the minimal reduction in SO_2 emissions does not support the high cost for installing the redundant compression. With a calculated Q/d below 10, IBGP will not impact the visibility of Carlsbad Caverns. Furthermore, the analysis does not support additional controls due to the costs of the controls.

APPENDIX A: RBLC TABLES

The RBLC tables for the turbines are shown in the attached Table A-1.

Table A-1 RBLC Search for Small Turbines – NO_X

PROCESS_NAME	THROUGHPUT		POLLUTANT	CONTROL_METHOD_DESCRIPTION
Five (5) Natural Gas Fired Combustion Turbines	37.6	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction
Cogeneration gas turbine	4.37	MW	Nitrogen Oxides (NOx)	SoLoNOx burner (Ultra lean Premix)
Aeroderivative Simple Cycle Combustion Turbine	263	MM BTU/h	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR), exclusive combustion of fuel gas, and good combustion practices.
FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	171	MMBTU/H	Nitrogen Oxides (NOx)	Dry low-NOx combustors
FG-TURBINES	10504	HP	Nitrogen Oxides (NOx)	Dry ultra-low NOx burners
FGTURNBINES (5 Simple Cycle CTs: EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5)	10504	HP	Nitrogen Oxides (NOx)	Dry ultra-low NOx burners.
TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	4.6	MMBTU/H	Nitrogen Oxides (NOx)	LEAN PRE-MIX TECHNOLOGY AND LIMITING THE FUEL TO NATURAL GAS ONLY
Small Combustion Turbines (<25MW)	10179	Horsepower	Nitrogen Oxides (NOx)	Dry-Low NOx Combustion
TURBINES 9,443-HP SIEMENS SGT-200-2S	9443	HP	Nitrogen Oxides (NOx)	DRY LOW-NOx COMBUSTION.
COMBUSTION TURBINE without DUCT BURNERS UNIT	2433	MMBtu/hr	Nitrogen Oxides (NOx)	SCR
Compression Turbine	20000	hp	Nitrogen Oxides (NOx)	Solar's SoLoNOx dry emission control technology
(2) simple cycle turbines	190	MW	Nitrogen Oxides (NOx)	DLN burners, limited operation
P90 â€“ Natural Gas-Fired Emergency Generator	9.51	mmBTU/hr	Nitrogen Oxides (NOx)	Good Combustion Practices and the Use of Turbocharger and Aftercooler
TURBINES S35-S36	12555	HP	Nitrogen Oxides (NOx)	SOLONOX
TURBINE S34	3856	HP	Nitrogen Oxides (NOx)	SOLONOX

APPENDIX B: COST ANALYSIS SPREADSHEETS

Attached are the cost analysis spreadsheets completed in the report.

Occidental Oil & Gas
Indian Basin Gas Plant - Four-factor Analysis Cost Estimate

Solar Centaur 40-4002 NG Turbine
Unit: ES-06/07

Inputs

Parameter	*Value*	*Units*	*Source*
Interest Rate:	5.50%	%	Cost Control Spreadsheet
Period:	20	years	Cost Control Spreadsheet
Turbine HP:	4000	hp	Permitted capacity (NSR PSD0295-M11)
Fuel Heat Value:	1031	BTU/scf	Application for TV Permit P103-R2M1
Heat Rate:	39.01	MMBTU/hr	Application for TV Permit P103-R2M1
2016 Actual Operating Hours:	8,664	hours	2016 EI calculations
2016 Actual Fuel Usage:	327.82	MMscf/yr	Heat Rate / Fuel Heat Value * 2016 Operating Hours

Base Case Emissions (101.16 ppm)

Parameter	*Value*	*Units*	*Source*
NO_X ppm:	101.2	ppm	2016 EI calculations
NO_X lb/hr:	12.62	lb/hr	2016 EI calculations
NO_X tpy:	54.67	tpy	2016 EI calculations

$SoLoNO_X$ (25 ppm)

Parameter	*Value*	*Units*	*Source*
NO_X Outlet Concentration:	25	ppm	Manufacturer's Guarantee for $SoLoNO_X$
NO_X Hourly Emission Rate:	3.12	lb/hr	
NO_X Annual Emission Rate:	13.51	tpy	

Equipment & Installation Labor Cost	$ 1,280,000		Manufacturer's Estimate, 2017 dollars
	$ 1,360,296		Manufacturer's Estimate, 2018 dollars (CEPCI)
Unit Uprating Cost	$ 150,000		Manufacturer's Estimate
Total Capital Investment	$ 1,510,296		
Annualized TCI:	$ 126,381		Based on interest rate, year and TCI
Annual O&M Costs[1]:	$ 30,407		
Total Annual Costs:	$ 156,787		
Emissions Reduction:		41.16 tpy	
Cost Effectiveness:	**$**	**3,809.25**	**$/ton**

[1] From Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Timeline for Compliance (Docket ID No. EPA-HQ-OAR-2015-0500) Section 3.3.3, Corrected from 1999 to 2018 dollars based on CEPCI.

Occidental Oil & Gas

Indian Basin Gas Plant - Four-factor Analysis Cost Estimate

Solar Centaur 40-4002 NG Turbine

Unit: ES-08/09

Inputs

Parameter	*Value*	*Units*	*Source*
Interest Rate:	5.50%	%	Cost Control Spreadsheet Default
Period:	20	years	Cost Control Spreadsheet Default
Turbine HP:	4000	hp	Permitted capacity (NSR PSD0295-M11)
Fuel Heat Value:	1031	BTU/scf	Application for TV Permit P103-R2M1
Heat Rate:	39.01	MMBTU/hr	Application for TV Permit P103-R2M1
2016 Actual Operating Hours:	8,014	hours	2016 EI calculations
2016 Actual Fuel Usage:	303.23	MMscf/yr	Heat Rate / Fuel Heat Value * 2016 Operating Hours

Base Case Emissions (100.11 ppm)

Parameter	*Value*	*Units*	*Source*
NO_X ppm:	100.1	ppm	2016 EI calculations
NO_X lb/hr:	12.62	lb/hr	2016 EI calculations
NO_X tpy:	50.57	tpy	2016 EI calculations

$SoLoNO_X$ (25 ppm)

Parameter	*Value*	*Units*	*Source*
NO_X Outlet Concentration:	25	ppm	Manufacturer's Guarantee for $SoLoNO_X$
NO_X Hourly Emission Rate:	3.15	lb/hr	
NO_X Annual Emission Rate:	12.63	tpy	

Equipment & Installation Labor Cost	$	1,280,000	Manufacturer's Estimate, 2017 dollars
	$	1,360,296	Manufacturer's Estimate, 2018 dollars (CEPCI)
Unit Uprating Cost	$	150,000	Manufacturer's Estimate
Total Capital Investment	$	1,510,296	
Annualized TCI:	$	126,381	Based on interest rate, year and TCI
Annual O&M Costs[1]:	$	30,407	
Total Annual Costs:	$	156,787	
Emissions Reduction:		37.94 tpy	
Cost Effectiveness:	**$**	**4,132.47 $/ton**	

[1] From Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Timeline for Compliance (Docket ID No. EPA-HQ-OAR-2015-0500) Section 3.3.3, Corrected from 1999 to 2018 dollars based on CEPCI.

Occidental Oil & Gas

Indian Basin Gas Plant - Four-factor Analysis Cost Estimate

Solar Centaur 40-4702 NG Turbine

Unit: ES-10/11

Inputs

Parameter	*Value*	*Units*	*Source*
Interest Rate:	5.50%	%	Cost Control Spreadsheet Default
Period:	20	years	Cost Control Spreadsheet Default
Turbine HP:	4700	hp	Permitted capacity (NSR PSD0295-M11)
Fuel Heat Value:	1031	BTU/scf	Application for TV Permit P103-R2M1
Heat Rate:	43.1	MMBTU/hr	Application for TV Permit P103-R2M1
Permitted Operating Hours:	8,760	hours	
Fuel Usage:	366.20	MMscf/yr	Heat Rate / Fuel Heat Value * Operating Hours

Base Case Emissions (158.25 ppm)

Parameter	*Value*	*Units*	*Source*
NO_X ppm:	158.253	ppm	Stack Test dated 11/29/2018
NO_X lb/hr:	21.78	lb/hr	Stack Test dated 11/29/2018
NO_X tpy:	95.40	tpy	Calculated assuming 8,760 hours of operation per year

$SoLoNO_X$ (25 ppm)

Parameter	*Value*		*Units*	*Source*
NO_X Outlet Concentration:		25	ppm	Manufacturer's Guarantee for $SoLoNO_X$
NO_X Hourly Emission Rate:		3.44	lb/hr	
NO_X Annual Emission Rate:		15.07	tpy	
Equipment & Installation Labor Cost	$	1,280,000		Manufacturer's Estimate, 2017 dollars
	$	1,360,296		Manufacturer's Estimate, 2018 dollars (CEPCI)
Annualized TCI:	$	113,829		Based on interest rate, year and TCI
Annual O&M Costs[1]:	$	33,461		
Total Annual Costs:	$	147,290		
Emissions Reduction:		80.33	tpy	
Cost Effectiveness:	**$**	**1,833.65**	**$/ton**	

[1] From Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Timeline for Compliance (Docket ID No. EPA-HQ-OAR-2015-0500) Section 3.3.3, Corrected from 1999 to 2018 dollars based on CEPCI.

Occidental Oil & Gas

Indian Basin Gas Plant - Four-factor Analysis Cost Estimate

Acid Gas Flaring from AMINE-1 & SELEXOL

Unit: ES-50-SSM (AGI Flaring Records used to asses the cost to control these emissions)

Inputs

Parameter	*Value*	*Units*	*Source*
Interest Rate:	5.50%	%	Cost Control Spreadsheet
Period:	20	years	Estimated based on the corrosive nature of the acid gas being compressed in the unit.

Base Case Emissions

Parameter	*Value*	*Units*	*Source*
SO_2 tpy:	41.92	tpy	2016 EI calculations

Redundant Compressor to Reduce AGI Flaring

Parameter	*Value*	*Units*	*Source*
SO_2 Control Efficiency:	90.0%	%	Calculated based on 2016 actual AGI flaring emissions and preventable flaring event emission
SO_2 Annual Emission Rate:	4.20	tpy	Actual SO_2 emissions from 2016 maintenance flaring events. 3 hour event duration estimated

Total Capital Investment:	$	11,000,000		Manufacturer's Estimate, 2018 dollars
Annualized TCI:	$	920,473		Based on interest rate, year and TCI
Annual O&M Costs:	$	120,000		Occidental Oil & Gas Estimate, 2018 dollars
Total Annual Costs:	$	1,040,473		
Emissions Reduction:			37.72 tpy	
Cost Effectiveness:	**$**	**27,581.01**	**$/ton**	

REGIONAL HAZE FOUR-FACTOR ANALYSIS ADDENDUM

OXY USA WTP Limited Partnership
Indian Basin Gas Plant

Prepared By:

TRINITY CONSULTANTS
9400 Holly Ave NE
Building 3, Suite 300
Albuquerque, NM 87122
(505) 266-6611

February 2020

Project 193201.0194

Environmental solutions delivered uncommonly well

Oxy appends the Four-Factor Analysis for Indian Basin Gas Plant with the following information provided in this addendum. In Oxy's original Four-Factor Analysis report submitted on October 31, 2019, any unit from each facility which had NO_x or SO_2 emissions greater than 10 lb/hr and 5 tpy was analyzed. Below in blue and italicized are Oxy's responses to the NMED's letter dated December 23, 2019 for additional information on the 4FA submitted on November 1, 2019 to the NMED.

1. Sour Gas Amine Treating Units

a. Consider and discuss adding a secondary control to the acid gas injection (AGI) system to reduce flaring emissions, such as LO-CAT sulfur recovery technology. If technically feasible, include a four-factor analysis.

Oxy Response: The AGI system is a fully enclosed system, with no clear/viable way Oxy could add a new system such as LO-CAT technology. The Indian Basin Plant does have a Sulfur Recovery Unit that removes H_2S from the acid gas flow to create elemental sulfur. This unit has been shut down since the AGI well was installed and operational but was known to have very poor reliability. The installation of a LO-CAT system would be technically infeasible.

2. **Flaring:** Please provide the following information for the flare Units at the IBGP Unit ES-42 Startup, Shutdown & Maintenance (SSM) (NOX and SO2), ES-50-SSM (SO2):
   a. Provide a description of each flare, the design and type, and its purpose.
   b. List and describe the reasons that trigger each type of flaring event. This is to identify and clarify the causes to help find potential solutions to reduce flaring emissions.
   c. Complete a review and include an analysis about how the entire facility and/or source specific operations can be improved to reduce the frequency of SSM flaring events. If it is not possible to make any improvements to the facility or its processes to reduce SSM flaring events, then please explain why.
   d. Include a discussion of any potential alternative control options or operational changes that could reduce flaring NOX and/or SO2 emissions, including but not limited to,
      i. infrastructure that allows re-routing or recirculating the gas within the facility or outside of the facility until an SSM event is over;
      ii. sulfur absorbent technology used to remove sulfur from pipelines and other auxiliary equipment to reduce inlet or plant flaring SO2 emissions;
      iii. Gas Capture Plans with facilities located downstream and upstream similar to those required for producers to better synchronize upstream and downstream services with the IBGP;
      iv. use of remote capture equipment; and
      v. better infrastructure planning and changes to existing infrastructure that connects the downstream and upstream operations to the IBGP to ensure that there is adequate processing capacity to move produced gas to market.
   e. For any technically feasible solutions, complete and submit a four-factor analysis. For additional information regarding potential alternative controls to flaring see the New Mexico Methane Strategy webpage.

Oxy Response: The majority of SSM events are related to startup and shutdown of the Turbines at the Plant. The Plant has worked to implement Solar Turbotronics controls on the Solar Turbines at the Plant. These controls help to minimize downtime of the units and provide the units with a longer lifespan before they need to be overhauled. During SSM events, Oxy reduces emissions through work

practice standards and good air pollution control practices. The flares at the facility are permitted with the least amount of emissions due to the fact Oxy has already reduced flaring emissions as low as the plant can possibly operate with. The acid gas flare is only used during maintenance or an upset of the AGI well. There are no further ways to reduce emissions from the acid gas flare other than those stated in the original 4FA submittal on November 1, 2019.

As for the inlet residue flare, this flare has minimal emissions associated with it. This flare is only used during maintenance events and when the plant has a turnaround. There are no further ways to reduce emissions from this flare. When maintenance or turnaround events are scheduled, Oxy makes every effort to schedule these events along with downstream and upstream facilities. This will help to mitigate emissions further during these types of events.

The NMED also listed a "remote gas capture system" as an alternative to flaring but this technology would be technically infeasible for the facility. The remote gas capture system would have to be able to remove acid gas from the stream and be able to accommodate 200 MMSCFD of inlet gas. Oxy is also contractually obligated to meet certain natural gas specifications before the gas can be sent to downstream facilities. If these specifications are not met, the downstream facilities will not accept the gas. At this time, Oxy does not know of any system that is capable of handling this amount of gas and removing the acid gas from the stream.

Oxy has the infrastructure needed to accommodate the gas the facility processes. There are no further infrastructure changes that could mitigate SSM emissions further for the facility.

3. **Simple Cycle Natural Gas Fueled Turbines**

Please provide the following information for Four Factor Analyses for NOX from Simple Cycle Turbines Unit Numbers ES-06/07, EP-08/09, and ES-10/11:

a. Provide the Good Combustion Practices and the routine maintenance schedule and procedures that are currently used to help mitigate NOx emissions and are proposed as a feasible control.
Oxy Response: Oxy has a maintenance contract with Solar for routine maintenance. Solar provides field support and performs all needed maintenance on Oxy's Turbines. The maintenance procedures followed are the ones Solar provides for the facility turbines.

b. Provide vendor specifications for the SoLoNOX Dry Low NOx (DLN) combustion technology that includes the guaranteed NOX emission rates used in cost analysis, the cost information, recommendations, and equipment specifications for the turbine control estimates.
Oxy Response: The NOx emission rate guarantee is attached. The cost recommendation was based on a similar unit that was installed at the facility and the invoice log is provided. This cost is considered confidential business information and is being submitted as a separate document.

c. How will upgrading the turbine combustors with SoLoNOX affect the turbine capacities and the emission rates of NOX and CO?
Oxy Response: The NOx and CO for the units will be reduced but the turbine capacities will be increased and then derated to the permitted limit in order to not increase capacity for the unit.

d. Provide the documentation from the turbine vendor stating why water injection is not technically feasible for Solar Turbines.
Oxy Response: Per correspondence with Solar, the turbines were not designed for water injection. Solar does not offer this older technology on the turbines. The only technology provided in Solar technical data sheets is for dry low NOx. None of the data sheets provide information on wet NOx which would be associated with water injection.

e. Provide the basis for the following statement; "communication with Solar has indicated that SCR *[selective catalytic reduction]* controls are available for each of the turbine models assessed here

but the facility engineers have determined the additional power demands required to install SCR controls on the turbines are infeasible". Is the increase in power demand not technically feasible or too costly? If this determination is based on cost, then a cost analysis that includes the increase in energy demand, must be provided.

Oxy Response: The increase in power is not technically feasible. There is no extra power at the facility to operate the SCR equipment. Oxy believes the major modification that would need to be completed in order to add a substation and add the control is outside the scope of this analysis. A full engineering redesign of the facility would need to take place to determine if a new substation and the SCR controls could be added to the facility. This engineering redesign would take months to determine the cost needed to modify the facility and if the redesign is even feasible. Oxy believes this redesign cost would be more expensive than the SoloNOx cost estimate that was provided since the addition of the SoloNOx would not require a redesign of the facility.

f. Consider and include a discussion on the feasibility and cost of load management including limited operating hours to reduce emissions.

Oxy Response: Oxy has contracts in place that require the current loads and hours permitted for the units. This is not an option for the units at the site.

g. Provide the electronic spreadsheets used for control technology cost calculations.

Oxy Response: These have been attached to the documents.

h. Please include a discussion of the following control options to reduce NO_X emissions:

   i. catalytic combustion such as a XONON^{TM} developed by Catalytic Combustion Systems, Incorporated (CESI);

   Oxy Response: This control option was not provided by Oxy as an option to control the turbines at the site. When completing an RBLC search over the last ten years, XONON has not been installed on turbines. The most notable control was a dry low NOx burner which Oxy discussed in the original submittal. Oxy has historically had issues with Solar turbines that were operated with different equipment that was not from Solar. There were more instances of downtime and overhauls had to be completed more often.

   ii. lean and staged (DLN) combustors from turbine manufacturers other than Solar and complete a Four-Factor analysis on technically feasible options. That Solar does not manufacturer a particular control method or turbine combustor is not grounds for eliminating an option for technical reasons.

   Oxy Response: SoloNOx is a dry low NOx combustor manufactured by Solar. Therefore, this method was discussed in the original 4FA submittal and will not be provided further in this document. Please note that adding aftermarket combustors to the turbines would void the warranty Oxy has with Solar. There would be no reason to install aftermarket controls when Solar manufactures controls specifically designed for the Solar Turbines.

APPENDIX A: SUPPORTING INFORMATION

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer	Engine Model: CENTAUR 40-4700S CS/MD 59F MATCH
Job ID	
Inquiry Number	Fuel Type: SD NATURAL GAS; Water Injection: NO
Run By: David A Pocengal; Date Run: 1-Jun-16	Engine Emissions Data: REV. 0.1

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
1 — 5151 HP — 100.0% Load — Elev. 0 ft — Rel. Humidity 60.0% — Temperature 0 Deg. F			
PPMvd at 15% O2	42.00	50.00	25.00
ton/yr	34.55	25.04	7.17
lbm/MMBtu (Fuel LHV)	0.168	0.122	0.035
lbm/(MW-hr)	2.05	1.49	0.43
(gas turbine shaft pwr) lbm/hr	7.89	5.72	1.64
2 — 5025 HP — 100.0% Load — Elev. 0 ft — Rel. Humidity 60.0% — Temperature 20.0 Deg. F			
PPMvd at 15% O2	42.00	50.00	25.00
ton/yr	33.66	24.40	6.99
lbm/MMBtu (Fuel LHV)	0.168	0.122	0.035
lbm/(MW-hr)	2.05	1.49	0.43
(gas turbine shaft pwr) lbm/hr	7.69	5.57	1.60
3 — 4678 HP — 100.0% Load — Elev. 0 ft — Rel. Humidity 60.0% — Temperature 59.0 Deg. F			
PPMvd at 15% O2	42.00	50.00	25.00
ton/yr	31.30	22.69	6.50
lbm/MMBtu (Fuel LHV)	0.167	0.121	0.035
lbm/(MW-hr)	2.05	1.48	0.43
(gas turbine shaft pwr) lbm/hr	7.15	5.18	1.48

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg C, and between 50% and 100% load for gas, fuel, and between 65% and 100% load for liquid fuel (except f or the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg C and betwee
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer	Engine Model: CENTAUR 40-4700S CS/MD 59F MATCH
Job ID	
Inquiry Number	Fuel Type: SD NATURAL GAS; Water Injection: NO
Run By: David A Pocengal; Date Run: 1-Jun-16	Engine Emissions Data: REV. 0.1

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
4 — 4008 HP — 100.0% Load — Elev. 0 ft — Rel. Humidity 60.0% — Temperature 85.0 Deg. F			
PPMvd at 15% O2	42.00	50.00	25.00
ton/yr	27.83	20.17	5.78
lbm/MMBtu (Fuel LHV)	0.166	0.120	0.034
lbm/(MW-hr)	2.13	1.54	0.44
(gas turbine shaft pwr) lbm/hr	6.35	4.60	1.32

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg C, and between 50% and 100% load for gas, fuel, and between 65% and 100% load for liquid fuel (except f or the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg C and betwee
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED ENGINE PERFORMANCE

Customer	Model: CENTAUR 40-4700S
Job ID	Package Type: CS/MD
Run By: David A Pocengal — Date Run: 1-Jun-16	Match: 59F MATCH
Engine Performance Code: REV. 4.17.1.19.11 — Engine Performance Data: REV. 2.3	Fuel System: GAS
	Fuel Type: SD NATURAL GAS

DATA FOR NOMINAL PERFORMANCE

Elevation	feet	0
Inlet Loss	in H2O	0
Exhaust Loss	in H2O	0
Accessory on GP Shaft	HP	15.5

		1	2	3	4
Engine Inlet Temperature	deg F	0	20.0	59.0	85.0
Relative Humidity	%	60.0	60.0	60.0	60.0
Driven Equipment Speed	RPM	15500	15500	15500	15500
Specified Load	HP	FULL	FULL	FULL	FULL
Net Output Power	HP	5151	5025	4678	4008
Fuel Flow	mmBtu/hr	46.85	45.68	42.69	38.30
Heat Rate	Btu/HP-hr	9095	9091	9125	9557
Therm Eff	%	27.977	27.987	27.884	26.624
Engine Exhaust Flow	lbm/hr	166631	161458	150273	137230
PT Exit Temperature	deg F	774	793	835	855
Exhaust Temperature	deg F	774	793	835	855

Fuel Gas Composition (Volume Percent)

Methane (CH4)	92.79
Ethane (C2H6)	4.16
Propane (C3H8)	0.84
N-Butane (C4H10)	0.18
N-Pentane (C5H12)	0.04
Hexane (C6H14)	0.04
Carbon Dioxide (CO2)	0.44
Hydrogen Sulfide (H2S)	0.0001
Nitrogen (N2)	1.51

Fuel Gas Properties

LHV (Btu/Scf)	939.2	Specific Gravity	0.5970	Wobbe Index at 60F	1215.6

This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

APPENDIX B: CONFIDENTIAL BUSINESS INFORMATION

This information will be provided to the NMED separately as it is classified as confidential business information (CBI).

From: Serrano, Femi A
To: Butt, Neal, ENV; AErenstein@trinityconsultants.com
Cc: Singleton,Kerwin, NMENV; Baca, Michael, ENV; Jones, Mark, ENV; Zyla, Rhett, NMENV
Subject: [EXT] RE: Call to Discuss Regional Haze Four-factor Analysis for OXY - Indian Basin Gas Plant
Date: Wednesday, October 21, 2020 8:31:11 AM
Attachments: RE Call to Discuss Regional Haze Four-factor Analysis for OXY - Indian Basin Gas Plant.msg

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Hello Neal,

Does the attached email from the Assistant Treasurer suffice? Please advise.

Kind Regards,

Femi Serrano, PE, PMP | Environmental Lead | Office 713.366.5331 | Fax 713.985.1404 | femi_serrano@oxy.com

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From: Butt, Neal, NMENV <Neal.Butt@state.nm.us>
Sent: Tuesday, October 20, 2020 6:02 PM
To: Serrano, Femi A <Femi_Serrano@oxy.com>; AErenstein@trinityconsultants.com
Cc: Singleton,Kerwin, NMENV <Kerwin.Singleton@state.nm.us>; Baca, Michael, NMENV <michael.baca1@state.nm.us>; Jones, Mark, NMENV <Mark.Jones@state.nm.us>; Zyla, Rhett, NMENV <Rhett.Zyla@state.nm.us>
Subject: [EXTERNAL] RE: Call to Discuss Regional Haze Four-factor Analysis for OXY - Indian Basin Gas Plant

WARNING - This message is from an EXTERNAL SENDER - be CAUTIOUS, particularly with links and attachments.

Good Afternoon Femi,

Thank you for your responses. In terms of your company-specific interest rate for the cost of capital for the installation of air pollution equipment, I appreciate that you have verified this with the Oxy Treasury Team that an appropriate cost is approximately 10 – 12%. You stated that this was based on a recent analysis provided to Technical Accounting and KPMG from Treasury where they calculated that a reasonable WACC is 10 – 12%.

EPA has indicated to us that they are expecting documentation to defend the interest rate used for submitted four factor analyses. Therefore we request that you provide documentation to support your proposed interest rate. This could be a letter from the chief financial officer for the institution that lends to your company, or from an official with your company (your company's CFO, for instance) that is in a position to know your company's costs of debt and equity.

Regards,

Neal

From: Schmitz, Jason A
To: Serrano, Femi A
Subject: RE: Call to Discuss Regional Haze Four-factor Analysis for OXY - Indian Basin Gas Plant
Date: Wednesday, September 30, 2020 9:15:59 AM
Attachments: image001.jpg

Hi Femi – good morning. Yes, as discussed, it would be more appropriate to use Oxy's WACC as the cost to fund capital projects.
An appropriate cost is ~10%. Recent analysis provided to Technical Accounting and KPMG from Treasury calculated that a reasonable WACC is 10-12%.
Let me know if you need anything else.
Regards,
Jason

Jason Schmitz
Occidental Petroleum Corporation
Assistant Treasurer
Work: 713.497.2059
Cell: 805.766.2997
jason_schmitz@oxy.com

From: Serrano, Femi A
Sent: Wednesday, September 30, 2020 7:58 AM
To: Schmitz, Jason A
Subject: RE: Call to Discuss Regional Haze Four-factor Analysis for OXY - Indian Basin Gas Plant

Good morning Jason,
Thank you very much for your explanation regarding the use of a weighted average cost to capital of 10-12% from a recent analysis in June. If you have any additional details to buttress this, please reply to this email.
I plan respond to NMED sometime today. Have a wonderful day!
Kind Regards,

Femi Serrano, PE, PMP | Environmental Lead | Office 713.366.5331 | Fax 713.985.1404 |
femi_serrano@oxy.com
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From: Schmitz, Jason A <Jason_Schmitz@oxy.com>
Sent: Tuesday, September 29, 2020 3:07 PM
To: Serrano, Femi A <Femi_Serrano@oxy.com>
Subject: RE: Call to Discuss Regional Haze Four-factor Analysis for OXY - Indian Basin Gas Plant

Hi Femi – thanks for the note, happy to discuss. Let me know if you have time this afternoon; I'm available starting at 4:30pm.

If not, I'm available tomorrow morning starting at 10:00am.
Let me know what works best, just call my cell. Talk soon.

Regards,
Jason
Jason Schmitz
Occidental Petroleum Corporation
Assistant Treasurer
Work: 713.497.2059
Cell: 805.766.2997
jason_schmitz@oxy.com

From: Serrano, Femi A
Sent: Tuesday, September 29, 2020 3:03 PM
To: Schmitz, Jason A
Subject: FW: Call to Discuss Regional Haze Four-factor Analysis for OXY - Indian Basin Gas Plant

Hi Jason,

I had a question from NMED about interest rates and was directed to you by James Holtz. Please see NMED's comments below. Do you have a few minutes to discuss? Please advise.

- OXY has indicated that the interest rate was 5.5% at the time of the analysis. However, NMED's intention is to use a bank prime rate of 3.25% for its cost analysis unless OXY can provide information on a percentage rate OXY would potentially be able to borrow at for the purchase of control equipment. If you have a company-specific interest rate for the cost of capital for the installation of air pollution equipment, please provide it, and any documentation that supports this rate.

Kind Regards,
Femi Serrano, PE, PMP | Environmental Lead | Office 713.366.5331 | Fax 713.985.1404 |
femi_serrano@oxy.com
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From: Serrano, Femi A
To: Baca, Michael, ENV
Cc: Jones, Mark, ENV; Miller, Kenneth, ENV
Subject: [EXTERNAL] RE: RE: Regional Haze Four Factor Analysis - OXY USA
Date: Friday, July 21, 2023 4:10:01 PM
Attachments: image001.png

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Hello Michael,

Update on status of IBGP. Oxy management has decided to maintain the Title V permit for the IBGP. Please let me know what our next steps would be.

Thank you!

Kind Regards,

Femi Serrano, PE, PMP
MANAGER AIR QUALITY, EOR
Office: 713.366.5331 | Email: femi_serrano@oxy.com | Houston Greenway Office

Zero In™ at oxy.com

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From: Serrano, Femi A
To: Baca, Michael, ENV
Cc: Jones, Mark, ENV; Miller, Kenneth, ENV
Subject: [EXTERNAL] RE: RE: RE: Regional Haze Four Factor Analysis - OXY USA
Date: Monday, August 14, 2023 4:31:33 PM
Attachments: image001.png

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Hello Michael,

Sorry for the late response, I was out of office when your email came and it has taken me some time to catch up on all the missed messages.

To answer your question below, there are currently no plans to replace those equipment that were removed from the site.

Thank you for your patience, and please let me know if there are any other questions.

Kind Regards,

Femi Serrano, PE, PMP
MANAGER AIR QUALITY, EOR
Office: 713.366.5331 | Email: femi_serrano@oxy.com | Houston Greenway Office

Zero In™ at oxy.com



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From: Baca, Michael, ENV <michael.baca1@env.nm.gov>
Sent: Friday, July 28, 2023 3:18 PM
To: Serrano, Femi A <Femi_Serrano@oxy.com>
Cc: Jones, Mark, ENV <Mark.Jones@env.nm.gov>; Miller, Kenneth, ENV <kenneth.miller@env.nm.gov>
Subject: RE: [EXTERNAL] RE: RE: Regional Haze Four Factor Analysis - OXY USA
Importance: High

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Hi Femi,

During our meeting, you stated that the permitted equipment had been removed and put in use at a different facility. What is your company's plan for replacing the equipment?

In the absence of any other information regarding the facilities operation, we plan on finalizing the Four Factor Analysis for your facility as it is permitted and presented in the original 4FA submittal.

Thank you,

Michael Baca | CS Manager | NMED AQB
michael.baca1@env.nm.gov | (505) 629-7891

D.11 Public Service Company of New Mexico

Supporting documentation for Public Service Company of New Mexico is provided below. Facility-specific documentation is provided first, followed by documentation pertaining to multiple facilities and/or the owner/operator. The following documents are included in this section (in reading order):

- San Juan Generating Station:
    - Administrative Permit Revision (12/27/2022)
    - Permit Closure Letter (12/28/2022)

Permitting Administrative Multi-Form

Use for NSR administrative permit revisions (including GCPs), TV administrative amendments, TV responsible official notifications, and other submittals required by a permit condition. Refer to Section 4 for instructions, acronyms, and mailing addresses.

Mail Application To: New Mexico Environment Department Air Quality Bureau 525 Camino de los Marquez, Suite 1 Santa Fe, New Mexico, 87505 Phone (505) 476-4300 Fax (505) 476-4375 www.env.nm.gov/aqb		For Department use only – Received Date: Received via email on 12/27/2022, jwk. ☑ Approved ☑ Completed ☐ Denied Permit revision number: PSD0063M12R3 TV P062R4M1 Reviewed by & date: Joseph Kimbrell Digitally signed by Joseph Kimbrell Date: 2022.12.28 07:55:19 -07'00'

Section 1: General Information – Required for All Submittals

1	Facility Name: San Juan Generating Station		
2	Preparer/Consultant Name: Paul Wade	Title: Senior Associate Engineer	
3	Email: pwade@montrose-env.com	Phone: (505) 830-9680 x6	
4	Address: 3500 G Comanche Rd NE, Albuquerque, NM 87107		
5	Air Permit Contact: Justine Vaivai	Title: Environmental Scientist	
6	Email: Justine.Vaivai@pnmresources.com	Phone: (505) 241-2027	
7	Address: 2401 Aztec Road, NE, MS Z100 87107		
8	Check all boxes below for which this submittal applies:	AI #: 1421	Permit #: NSR 0063, Title V P062

X NSR Construction Permit (20.2.72 NMAC) X TV Operating Permit (20.2.70 NMAC)	☐ NOI (20.2.73 NMAC) (Sections 2-B, 2-D) ☐ Notice of Exemption (20.2.72.202.B NMAC) (Section 2-F)	☐ PSD Permit (20.2.74 NMAC) ☐ Nonattainment Permit (20.2.79 NMAC)

Section 2: Details of Submittal

Only print and submit the pages necessary for your submittal. Print double sided head-to-toe, flip on short end (tablet). The Permit Section responds to all TV Administrative amendments and responds only to denials of NSR administrative revisions. Courier proof of delivery is required if you want confirmation that the Department received this submittal. Check the box(es) applicable to this submittal:

☐ 2-A(i) & 2-A(ii): Identical Engine or Turbine Replacements

☐ 2-B: Owner, Operator, and Name Changes to NOIs or Construction Permits

☐ 2-C: Ownership or Operational Control Changes for Title V Permits

☒ 2-D: Closing a Facility or Removing Units from a Permit or Canceling an NOI

☐ 2-E: Correct Typographical Error

☐ 2-F: Reporting Exempt Equipment for Minor Construction Permits or for No Permit Required (NPR) Facilities

☐ 2-G: Add Minor NSR Exempt Equipment to Construction Permits for PSD or Nonattainment Sources

☐ 2-H: Title V Responsible Official Designations

☐ 2-I: Submittals to the Permit Programs Manager

Section 3: Certification – Required for All Changes

Section 4: Form Instructions

Section 2-D: Closing a Facility, Removing Units from a Permit, or Canceling an NOI

(Administrative Revision)

Check the appropriate boxes and provide complete information in the table. Closing the permit does not relieve the permittee from any outstanding permit fees.

If any of the units being removed are emission control equipment explain how a permit, federal regulation, or state regulation will not be violated by removal of the control equipment.

☒ Cease operations of the entire facility and close the construction permit (20.2.72.219.A(1)(c) NMAC).

Date the facility ceased operating: 11/1/22, NSR Permit 0063.

☐ Retire an emissions unit and remove it from the construction permit (20.2.72.219.A(1)(c) NMAC).

Date unit(s) retired:
List all retired unit numbers to be removed from the permit:

☐ Close a construction permit for a facility or remove an emissions unit that has not and will not be constructed (20.2.72.219.A(1)(d) NMAC).

☐ Facility (plant) will not be constructed, or	☐ The following units will not be constructed and should be removed from the permit:

☐ Retire an emissions unit and remove it from the TV permit (20.2.70.404.A(1)(c) NMAC).

Date unit(s) retired:
List all retired unit numbers to be removed from the permit:

☒ Voluntary Discontinuation of the TV permit (20.2.70.400.I NMAC).

Explanation: SJGS ceased all operations on 11/1/2022, as noted in the NSR Permit 0063 cease operations notice above. With the application, PNM voluntarily discontinues Title V 0062 as of 11/1/2022.

☐ Close a construction permit that is no longer required.

Explanation:

☐ Removal of minor NSR exempt equipment.

Explanation:

☐ Cancel a Notice of Intent (check one or explain):

☐ PER is now below 20.2.73.200 NMAC threshold.	☐ Date the facility ceased operating:

Section 3: Certification – Required for All Submittals

Company Name: Public Service Company of New Mexico

I, Rodney Warner, hereby certify that the information and data submitted in this application are true and as accurate as possible, to the best of my knowledge and professional expertise and experience.

Signed this 21 day of December, 2022, upon my oath or affirmation, before a notary of the State of New Mexico.

Rodney Warner — 12/21/2022

Signature[1] — Date

Rodney Warner — Director, Plant Manager

Printed Name — Title

Scribed and sworn before me on this 21 day of December, 2022.

My authorization as a notary of the State of New Mexico expires on the 6 day of July, 2023.

Verleen King — 12/21/22

Notary's Signature — Date

Verleen King

Notary's Printed Name

STATE OF NEW MEXICO
NOTARY PUBLIC
VERLEEN KING
COMMISSION # 1076935
MY COMMISSION EXPIRES 07/06/2023

[1] For Title V applications, the signature must be of the Responsible Official as defined in 20.2.70.7.AE NMAC:

December 28, 2022

Certified Mail No. 7016 0340 0000 2154 9972
No return receipt

Justine Vaivai
Environmental Scientist
Public Service Company of New Mexico (PNM)
2401 Aztec Road NE MS Z100
Albuquerque, NM 87107

Ref: **Air Quality Operating Permit No.** P062-R4M1 and Acid Rain Permit P062A-R4M1
San Juan Generating Station
NSR Permit No. 0063-M12R3
Agency Interest No. 1421 - PRT20220002
AIRS No: 350450902

Dear Justine Vaivai:

The Air Quality Bureau (ABQ) is in receipt of Public Service Company of New Mexico (PNM)'s December 27, 2022, request to voluntarily discontinue the San Juan Generating Station Title V Operating Permit No. P062-R4M1 and Acid Rain Permit P062A-R4M1, pursuant to 20.2.70.400.I NMAC.

On December 27, 2022, the AQB received Public Service Company of New Mexico (PNM)'s request to close the New Source Review permit 0063-M12R3 for the facility located in San Juan County, New Mexico at latitude and longitude decimal degrees: 36.802056, -108.43875. The request to close the NSR permit was effective upon receipt per 20.2.72.219.A(3) NMAC.

With the closure of the NSR permit, the actions required to reduce the potential to emit of this facility to below Major Source thresholds have been met. Therefore, the Department has voluntarily discontinued Title V Operating Permit No. P062-R4M1 for the San Juan Generating Station as of December 28, 2022, and this facility will be removed from the list of major Title V sources in New Mexico.

If you have any questions, please contact me at 505-269-2718 or joseph.kimbrell@env.nm.gov.

Sincerely,

Elizabeth Kuehn
Digitally signed by Elizabeth Kuehn
Date: 2022.12.29 07:37:13 -07'00'

Liz Bisbey-Kuehn
Air Quality Bureau Chief

cc via email: EPA Region VI, 6PD-R, r6airpermits@epa.gov, LeDoux.Erica@epa.gov, Layton.mary@epa.gov
NMED-AQB Compliance & Enforcement Managers via email: Cindy.Hollenberg@env.nm.gov
David Feather, Permitting Section Manager,
Justine Vaivai, PNM Air Permit Contact, Justine.Vaivai@pnmresources.com
Claudette Horn, PNM, Claudette.Horn@pnmresources.com

D.12 Targa Midstream Services

Supporting documentation for Targa Midstream Services is provided below. Facility-specific documentation is provided first, followed by documentation pertaining to multiple facilities and/or the owner/operator. The following documents are included in this section (in reading order):

- Eunice Gas Processing Plant:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (11/2019)
    - Four-Factor Analysis SSM Flaring Addendum (12/2019)
- Monument Gas Plant:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (11/2019)
    - Four-Factor Analysis SSM Flaring Addendum (12/2019)
- Saunders Gas Plant:
    - Administrative Permit Revision (5/31/2024)
- Multiple Facilities and/or Owner/Operator:
    - Follow-Up Submittal (2/2020)
    - Follow-Up Submittal (3/12/2020)
    - Follow-Up Submittal (11/20/2020)
    - Follow-Up Submittal (2/16/2021)
    - Follow-Up Submittal (8/4/2023)

NMED Final Cost Evaluation
Targa Midstream Services - Eunice Gas Processing Plant

Facility Information

Targa Resources - Eunice	**Facility**
Seven 1970s 2SLB RICE, 1200 HP	**Units**
C-01 through C-07	**Unit IDs**
LEC	**Evaluated Pollution Control**
3.0	**Post-control Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
1200	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		C-01	C-02	C-03	C-04	C-05	C-06	C-07	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 1,800,000	$ 1,800,000	$ 1,800,000	$ 1,800,000	$ 1,800,000	$ 1,800,000	$ 1,800,000	Targa 8/4/23 FFA update, 2023$	Equipment, materials and labor to install
Other Direct Capital Costs 1 ($)	ODC1	$ 143,978	$ 143,978	$ 143,978	$ 143,978	$ 143,978	$ 143,978	$ 143,978	Targa 8/4/23 FFA update, mixed 2019$ and 2023$. Adjusted al	Cooling system, fuel system and custody transfer
Other Direct Capital Costs 2 ($)	ODC2	$ 383,509	$ 383,509	$ 383,509	$ 383,509	$ 383,509	$ 383,509	$ 383,509	Targa 8/4/23 FFA update, 2023$	Permitting, taxes and contingency
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Not specified by Targa
Total Capital Costs - Direct ($)	TCC	$ 2,327,487	$ 2,327,487	$ 2,327,487	$ 2,327,487	$ 2,327,487	$ 2,327,487	$ 2,327,487	-	PEC + ODC1 + ODC2 + IDC
Additional Capital ($)	AC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Targa included $8.4M for electrical substation upgrades needed to operate electric blowers associated with LEC. NMED omitted these costs for several reasons, most notably the fact that the vendor estimate provided by Targa specified turbochargers (which are powered by the engine's exhaust) instead of electric blowers.
Total Capital Investment ($)	TCI	$ 2,327,487	$ 2,327,487	$ 2,327,487	$ 2,327,487	$ 2,327,487	$ 2,327,487	$ 2,327,487	-	TCC + AC
Interest Rate (%)	R	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	20	20	20	20	20	20	20	Targa 8/4/23 FFA update	Consistent with other FFAs
Capital Recovery Factor	CRF	0.0981	0.0981	0.0981	0.0981	0.0981	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 228,308	$ 228,308	$ 228,308	$ 228,308	$ 228,308	$ 228,308	$ 228,308	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Incremental O&M of a LEC retrofit is expected to be negligible. Targa included $164K per engine in additional electricity costs for electric blowers. NMED omitted these costs for several reasons, most notably the fact that the vendor estimate provided by Targa specified turbochargers (which are powered by the engine's exhaust) instead of electric blowers.
Other Indirect Annual Costs ($/yr)	OAC	$ 93,099	$ 93,099	$ 93,099	$ 93,099	$ 93,099	$ 93,099	$ 93,099	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 321,408	$ 321,408	$ 321,408	$ 321,408	$ 321,408	$ 321,408	$ 321,408	-	ACC + OMC
NOx Control Efficiency (%)	Eff	86%	84%	83%	85%	85%	82%	84%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	199.3	170.3	167.2	190.2	200.3	162.3	184.9	CY2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	0%	0%	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	199.3	170.3	167.2	190.2	200.3	162.3	184.9	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	170.5	143.2	138.4	161.2	169.6	133.5	155.5	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 1,885**	**$ 2,244**	**$ 2,322**	**$ 1,994**	**$ 1,895**	**$ 2,408**	**$ 2,066**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	1.00	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 1,885**	**$ 2,244**	**$ 2,322**	**$ 1,994**	**$ 1,895**	**$ 2,408**	**$ 2,066**	-	CE1 x PI

NMED Final Cost Evaluation
Targa Midstream Services - Eunice Gas Processing Plant

Facility Information

Targa Resources - Eunice	**Facility**
Seven 1970s 2SLB RICE, 1200 HP	**Units**
C-01 through C-07	**Unit IDs**
Replacement with new RICE	**Evaluated Pollution Control**
0.5	**Post-control Emissions Rate (g NOx/bhp-hr)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired spark ignited RICE >500 and <1875 bhp

Supporting Information

2020	**Calendar year associated with cost estimates**
1200	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		**C-01**	**C-02**	**C-03**	**C-04**	**C-05**	**C-06**	**C-07**	**Source**	**Methodology/Note**
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 3,872,400	$ 3,872,400	$ 3,872,400	$ 3,872,400	$ 3,872,400	$ 3,872,400	$ 3,872,400	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $3227/hp cost metric as Targa did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered RICE.
Interest Rate (%)	R	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	30	30	30	30	30	30	30	ERG experience based on discussions with RICE manufacturers	
Capital Recovery Factor	CRF	0.0847	0.0847	0.0847	0.0847	0.0847	0.0847	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 327,881	$ 327,881	$ 327,881	$ 327,881	$ 327,881	$ 327,881	$ 327,881	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	Incremental O&M reasonably negligible
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 327,881	$ 327,881	$ 327,881	$ 327,881	$ 327,881	$ 327,881	$ 327,881	-	ACC + OMC
NOx Control Efficiency (%)	Eff	98%	97%	97%	97%	97%	97%	97%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	199.3	170.3	167.2	190.2	200.3	162.3	184.9	CY2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	0%	0%	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	199.3	170.3	167.2	190.2	200.3	162.3	184.9	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	194.5	165.7	162.4	185.3	195.2	157.5	180.0	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 1,685**	**$ 1,978**	**$ 2,018**	**$ 1,769**	**$ 1,680**	**$ 2,082**	**$ 1,821**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 and thus assumed costs are in 2020$
Price Index	PI	1.34	1.34	1.34	1.34	1.34	1.34	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 2,259**	**$ 2,651**	**$ 2,705**	**$ 2,371**	**$ 2,251**	**$ 2,790**	**$ 2,441**	-	CE1 x PI

NMED Final Cost Evaluation
Targa Midstream Services - Eunice Gas Processing Plant

Facility Information

Targa Resources - Eunice	**Facility**
Seven 1970s 2SLB RICE, 1200 HP	**Units**
C-01 through C-07	**Unit IDs**
Replacement with EMD	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
1200	**Maximum Power Output (hp/unit)**
2050	**Maximum Power Output (hp/unit), C-13**
$8,377,732	**Cost of electrical substation upgrades (Targa 8/4/23 FFA update, 2023$)**
3	**Number of groups of units that will be replaced with EMD (for apportionment of substation costs)**

Economic Evaluation

Cost Component		Units C-01, C-02 and C-03	Units C-04, C-05 and C-06	Units C-07 and C-13	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 4,166,667	$ 4,166,667	$ 4,166,667	Targa 8/4/23 FFA update	Equipment, materials and labor to install one 3250 HP EMD unit and proportional share of cost of two backup units
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	Included in PEC
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	Included in PEC
Indirect Capital Costs ($)	IDC	$ 40,000	$ 40,000	$ 40,000	Targa 8/4/23 FFA update	Permitting cost
Total Capital Costs - Direct ($)	TCC	$ 4,206,667	$ 4,206,667	$ 4,206,667	-	PEC + ODC1 + ODC2 + IDC
Additional Capital ($)	AC	$ 2,792,577	$ 2,792,577	$ 2,792,577	Targa 8/4/23 FFA update	Substation upgrade cost spread across RICE groups; Targa did not include any costs for distribution line upgrades, so AC may be underestimated
Total Capital Investment ($)	TCI	$ 6,999,244	$ 6,999,244	$ 6,999,244	-	TCC + AC
Interest Rate (%)	R	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	25	25	25	Consistent with other FFAs	
Capital Recovery Factor	CRF	0.0897	0.0897	0.0897	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 627,907	$ 627,907	$ 627,907	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 322,685	$ 225,689	$ 301,721	-	AED + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 638,891	$ 444,898	$ 596,963	Engineering judgement	Assumes 60% load, 95% efficiency and $0.053/kWh
Additional Maintenance ($/yr)	AM	$ -	$ -	$ -	Engineering judgement	Incremental O&M reasonably negligible
Associated non-electricity O&M ($/yr)	AOM	$ 3,240	$ 3,240	$ 3,240	Targa 8/4/23 FFA update	Incremental maintenance at 54 hr/yr and $60/hr
Annual Fuel Credit ($/yr)	AFC	$ (319,445)	$ (222,449)	$ (298,481)	ERG calculation	Assumed equal to 50% of AED
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 950,592	$ 853,596	$ 929,628	-	ACC + OMC
NOx Control Efficiency (%)	Eff	100%	100%	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	536.8	552.8	367.6	CY2023 emissions testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	536.8	552.8	367.6	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	536.8	552.8	367.6	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 1,771**	**$ 1,544**	**$ 2,529**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 1,771**	**$ 1,544**	**$ 2,529**	-	CE1 x PI

NMED Final Cost Evaluation
Targa Midstream Services - Eunice Gas Processing Plant

Facility Information

Targa Resources - Eunice	**Facility**
Two pre-1972 boilers, 62.1 MMBTU/hr each	**Units**
B-01 and B-02	**Unit IDs**
FGR	**Evaluated Pollution Control**
30.0	**Post-control Emissions Rate (ppm NOx)**

Supporting Information

2023	**Calendar year associated with cost estimates**
62.1	**Maximum Heat Input (MMBtu/hr)**

Economic Evaluation

Cost Component		B-01	B-02	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	According to Targa, the estimated TCC is an adjusted average from several vendors and includes burner modifications, engineering, installation and related field services. Targa estimated TCI by increasing a vendor estimate (Combustion Control Systems, CBI) by 16% to presumably account for additional installation costs. This is reasonably consistent with the EPA Control Cost Manual.
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ 210,100	$ 210,100	Targa 8/4/23 FFA update	
Additional Capital ($)	AC	$ -	$ -	-	
Total Capital Investment ($)	TCI	$ 243,716	$ 243,716	Targa 8/4/23 FFA update	
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	30	30	Targa 8/4/23 FFA update	Vendor (Combustion Control Systems) evaluation (CBI)
Capital Recovery Factor	CRF	0.0847	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 20,636	$ 20,636	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 14,000	$ 14,000	Targa 8/4/23 FFA update	
Other Indirect Annual Costs ($/yr)	OAC	$ 9,749	$ 9,749	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 44,384	$ 44,384	-	ACC + OMC
NOx Control Efficiency (%)	Eff	67%	67%	Targa 8/4/23 FFA update	From ~90 to 30 ppm NOx
Baseline Actual NOx Emissions (ton/yr)	BAE	26.1	26.1	Estimated emissions rate and 8760 hr/yr	Recent emissions test not available
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	26.1	26.1	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	17.4	17.4	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 2,550**	**$ 2,550**	-	TAC/ER
Price Index	PI	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 2,550**	**$ 2,550**	-	CE1 x PI

NMED Final Cost Evaluation
Targa Midstream Services - Eunice Gas Processing Plant

Facility Information

Targa Resources - Eunice	**Facility**
Two pre-1972 boilers, 62.1 MMBTU/hr each	**Units**
B-01 and B-02	**Unit IDs**
LNB retrofit	**Evaluated Pollution Control**
9.0	**Post-control Emissions Rate (ppm NOx)**

Supporting Information

2023	**Calendar year associated with cost estimates**
62.1	**Maximum Heat Input (MMBtu/hr)**

Economic Evaluation

Cost Component		B-01	B-02	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 643,300	$ 643,300	Targa 8/4/23 FFA update	TCI is based on a vendor estimate (Combustion Control Systems) and includes burner modifications, engineering, installation and related field services.
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	30	30	Targa 8/4/23 FFA update	Vendor (Combustion Control Systems) evaluation (CBI)
Capital Recovery Factor	CRF	0.0847	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 54,469	$ 54,469	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	Engineering judgement	Incremental O&M expected to be negligible
Other Indirect Annual Costs ($/yr)	OAC	$ 25,732	$ 25,732	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 80,201	$ 80,201	-	ACC + OMC
NOx Control Efficiency (%)	Eff	90%	90%	Targa 8/4/23 FFA update	From ~90 to 9 ppm NOx
Baseline Actual NOx Emissions (ton/yr)	BAE	26.1	26.1	Estimated emissions rate and 8760 hr/yr	Recent emissions test not available
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	26.1	26.1	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	23.5	23.5	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 3,413**	**$ 3,413**	-	TAC/ER
Price Index	PI	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 3,413**	**$ 3,413**	-	CE1 x PI

NMED Final Cost Evaluation
Targa Midstream Services - Eunice Gas Processing Plant

Facility Information

Targa Resources - Eunice	**Facility**
Two pre-1972 boilers, 62.1 MMBTU/hr each	**Units**
B-01 and B-02	**Unit IDs**
SCR	**Evaluated Pollution Control**

Supporting Information

2024	**Calendar year associated with cost estimates**
62.1	**Heat Input Capacity (MMBTU/hr)**

Economic Evaluation

Cost Component		B-01	B-02	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 3,427,850	$ 3,427,850	EPA SCR Tool (2024$)	Likely underestimates total costs; does not include construction and engineering costs needed to create physical space.
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	20	20	Default per EPA Cost Control Manual	-
Capital Recovery Factor	CRF	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 336,245	$ 336,245	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 60,287	$ 60,287	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 2,834	$ 2,834	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 399,366	$ 399,366	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	90%	90%	EPA SCR Tool	Consistent with EPA and industry documentation.
Baseline Actual NOx Emissions (ton/yr)	BAE	26.1	26.1	Estimated emissions rate and 8760 hr/yr	Recent emissions test not available
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	26.1	26.1	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	23.5	23.5	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 16,998**	**$ 16,998**	-	TAC/ER

NMED Final Cost Evaluation
Targa Midstream Services - Eunice Gas Processing Plant

Facility Information

Targa Resources - Eunice	**Facility**
Two pre-1972 boilers, 62.1 MMBTU/hr each	**Units**
B-01 and B-02	**Unit IDs**
Replacement with new boiler	**Evaluated Pollution Control**
9.0	**Post-control Emissions Rate (ppm NOx)**

Supporting Information

2023	**Calendar year associated with cost estimates**
100	**Maximum Heat Input (MMBtu/hr, replacement)**

Economic Evaluation

Cost Component		B-01	B-02	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 1,876,000	$ 1,876,000	Previous ERG project; $1.4M (2020$) adjusted to 2023$ with CEPCI	Estimated PEC is likely exaggerated: the $1.4M figure was for a 100 MMBtu/hr boiler
Other Direct Capital Costs 1 ($)	ODC1	$ 281,400	$ 281,400	Engineering judgment	ODC1 are estimated installation costs = 15% of PEC
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ 2,157,400	$ 2,157,400	-	PEC + ODC1 + ODC2+ IDC
Additional Capital ($)	AC	$ -	$ -	-	Not anticipated
Total Capital Investment ($)	TCI	$ 2,157,400	$ 2,157,400	-	TCC + AC
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	30	30	ERG experience based on discussions with manufacturers	
Capital Recovery Factor	CRF	0.0847	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 182,670	$ 182,670	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	-	Incremental O&M reasonably negligible
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 182,670	$ 182,670	-	ACC + OMC
NOx Control Efficiency (%)	Eff	90%	90%	-	From ~90 to 9 ppm NOx
Baseline Actual NOx Emissions (ton/yr)	BAE	26.1	26.1	Estimated emissions rate and 8760 hr/yr	Recent emissions test not available
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	26.1	26.1	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	23.5	23.5	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 7,773**	**$ 7,773**	-	TAC / ER
Price Index	PI	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 7,773**	**$ 7,773**	-	CE1 x PI

NMED Final Cost Evaluation
Targa Midstream Services - Eunice Gas Processing Plant

Unit B-01: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	62.1	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	527,639,185	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3415	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.0960	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0096	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit B-01: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	62	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	527,639,185	scf/Year
Actual Annual fuel consumption (Mactual) =		527,639,185	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	90.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	5.37	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	23.50	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.13	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.13	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.0	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	246.76	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet
		#VALUE!	

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	2	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	7	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	1	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	400	gallons (storage needed to store a 14 day reagent supply rounded to t
		2,024	
		797.6	
		7.5	

Capital Recovery Factor:

Parameter	Equation	0.529
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 =	0.0981
	Where n = Equipment Life and i= Interest Rate	255

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	36.76	kW

Unit B-01: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$3,427,850	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$60,287 in 2024 dollars
Indirect Annual Costs (IDAC) =	$339,106 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$399,393 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$17,139 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$4,451 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$32,205 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$6,492 in 2024 dollars
Direct Annual Cost =		$60,287 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,834 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$336,272 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$339,106 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$399,393 per year in 2024 dollars
NOx Removed =	24 tons/year
Cost Effectiveness =	$16,995 per ton of NOx removed in 2024 dollars

Unit B-02: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	62.1	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	527,639,185	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3415	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.0960	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0096	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit B-02: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	62	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	527,639,185	scf/Year
Actual Annual fuel consumption (Mactual) =		527,639,185	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	90.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	5.37	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	23.50	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.13	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.13	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.0	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	246.76	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet
		#VALUE!	

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	2	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	7	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	1	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	400	gallons (storage needed to store a 14 day reagent supply rounded to t
		2,024	
		797.6	
		7.5	

Capital Recovery Factor:

Parameter	Equation	0.529
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 =	0.0981
	Where n = Equipment Life and i= Interest Rate	255

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	36.76	kW

Unit B-02: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$3,427,850	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$60,287 in 2024 dollars
Indirect Annual Costs (IDAC) =	$339,106 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$399,393 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$17,139 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$4,451 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$32,205 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$6,492 in 2024 dollars
Direct Annual Cost =		$60,287 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,834 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$336,272 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$339,106 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$399,393 per year in 2024 dollars
NOx Removed =	24 tons/year
Cost Effectiveness =	$16,995 per ton of NOx removed in 2024 dollars

REGIONAL HAZE FOUR-FACTOR ANALYSIS

Targa Midstream Services LLC – Eunice Gas Plant

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Project 193201.0194

Environmental solutions delivered uncommonly well

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1. EXECUTIVE SUMMARY

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR).[1] The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across the United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

> *(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A).*
>
> *(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B).*

Currently, we are in the second planning period for national regional haze efforts. There are a few key distinctions from the processes that took place during the first planning period. Most notably, the second planning period analysis will distinguish between "natural" and "anthropogenic" sources. Using a Photochemical Grid Model (PGM), the Western Regional Air Partnership (WRAP) in coordination with the EPA will compare anthropogenic source contributions against natural background concentrations.

Pursuant to 40 CFR 51.308(d)(3)(iv), "The State must identify all anthropogenic sources of visibility impairment considered by the State in developing its long-term strategy. The State should consider major and minor stationary sources, mobile sources, and area sources." To accomplish this for major stationary sources, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for Title V sources and screened each facility's potential impact on visibility in Class I areas using a "Q/d" analysis, where "Q" is the magnitude of emissions that could impact ambient visibility, and "d" is the distance of a facility to a Class I area. From this analysis, 24 facilities were identified by the NMED. On July 19, 2019 the NMED informed Targa Midstream Services LLC (Targa) that its Eunice Gas Plant was identified as one of the sources potentially contributing to regional haze at the Carlsbad Caverns National Park Class I Area.

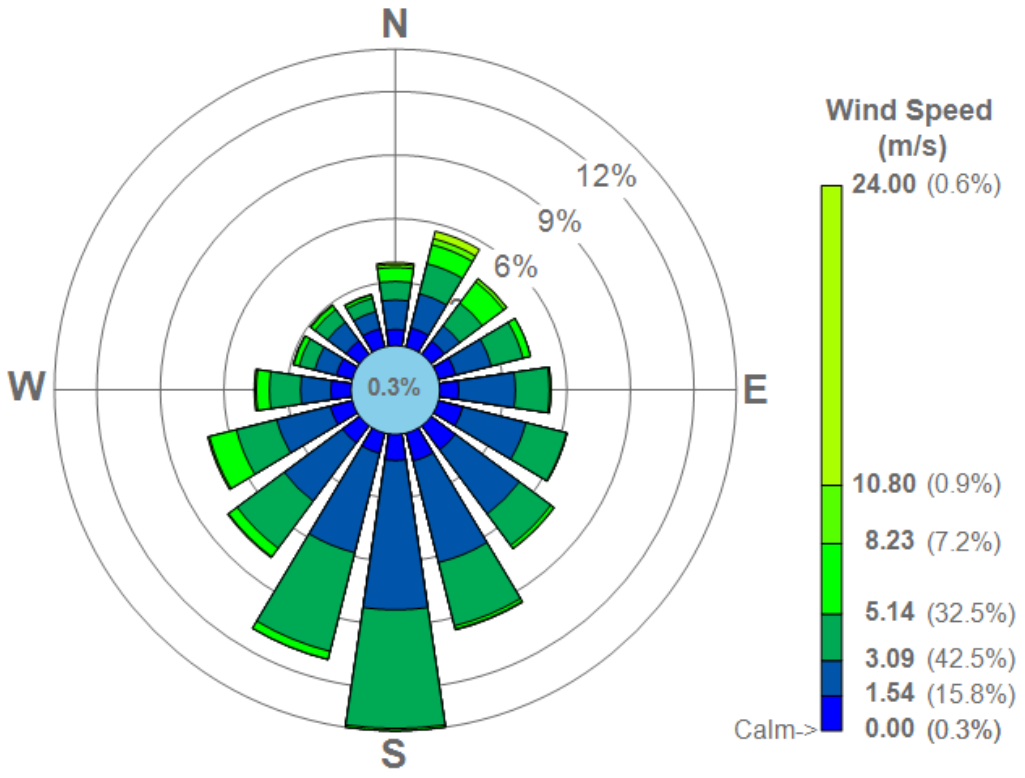
[1] Federal Register / Vol. 64, No. 126 /Thursday, July 1, 1999 (https://www.govinfo.gov/content/pkg/FR-1999-07-01/pdf/99-13941.pdf).

1.1. CONTRIBUTION TO VISIBILITY

1.1.1. Lack of Contribution to Visibility Impairment Due To Prevailing Winds

The NMED did not consider actual contribution to visibility impairment when selecting sources for the Four-Factor Analysis, but this is a critical factor in establishing realistic reasonable progress goals for Class I areas. In Figure 1-1 below, the prevailing wind from Hobbs, NM, can be used to estimate this facility's potential impact on the nearest Class I Area, Carlsbad Caverns National Park. Targa's Eunice Gas Plant is located approximately 73.5 miles northeast at a wind vector of 76.5 degrees from the Carlsbad Caverns. The 2015 meteorological data from the NMED website at the Hobbs, NM meteorological station shows that wind blows from 56.3 to 78.8 degrees at a frequency of approximately 4.5%.[2] Based off this infrequent amount of time the wind blows from Targa's Eunice Gas Plant toward Carlsbad Caverns, Targa believes that it is unlikely that the facility's potential emissions impact visibility at Carlsbad Caverns. Therefore, when balancing retrofit costs and visibility improvements, NMED should remain mindful that emissions from this facility are unlikely to contribute to regional haze at Carlsbad Caverns.

Figure 1-1. Hobbs, NM Meteorological Data, 2015 Wind rose



[2] https://www.env.nm.gov/air-quality/meteorological-data/

1.1.2. Already Effective SO_2 Controls

Further, with respect to SO_2 emissions, Targa controls H_2S emissions from the amine unit through operation of an acid gas injection (AGI) well and is in the process of adding redundant electric compression to the AGI well system to further reduce SO_2 emissions from the flare during SSM and malfunction events. The addition of the redundant electric compression is solely required by a Settlement Agreement and Stipulated Final Compliance Order between the Environmental Protection Division of the New Mexico Environment Department and Targa Midstream Services LLC. Targa expects this project to reduce SO_2 flaring emissions at Eunice Gas Plant by approximately 200-250 tons per year. The installation of the redundant compression constitutes effective emission control technology to meet emission reductions required under the Settlement Agreement. This project will be complete by December 31, 2020; therefore, occurring during the 2nd Planning Period. There are no further SO_2 control options for the amine unit. Thus, the only equipment at this facility subject to this regional haze evaluation emit NOx.

Per 40 CFR 51.308(f)(2) of the Regional Haze rule, the NMED must determine emission reduction measures that are necessary to make reasonable further progress. The NMED, in an outreach webinar on Regional Haze Planning held on October 2, 2019, presented data on the most impaired days. This presentation identified ammonium sulfate as the largest contributor of visibility impairment in the National Parks of New Mexico. Ammonium sulfate is a byproduct of gaseous sulfur dioxide which becomes oxidized in the atmosphere to form sulfate particulate matter. This sulfate particulate matter is composed of sulfuric acid and corresponding salts such as ammonium sulfate.[3] Since this information indicates the major contribution to regional haze is from sulfur dioxide emissions, not nitrogen dioxide emissions, the NMED should ensure that any required NO_X reductions show significant contribution to improving visibility prior to requiring capital expenditures. Because emissions from Targa's Eunice Gas Plant are not expected to impact visibility in the Carlsbad Caverns National Park Class I Area based on predominant wind direction (see Section 1.1), the NMED should find all technically feasible NO_X controls for the Eunice Gas Plant economically unreasonable.

1.2. EQUIPMENT ANALYSIS

In coordination with guidance provided by WRAP, the NMED devised criteria to determine specific equipment that is subject to the four factor analysis. In the NMED's notification letter to Targa, they specify that any equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The equipment at the facility that is subject to this analysis, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant, are reported in Table 1.

[3] Air Quality and Stationary Source Emission Control, Committee on Public Works United States Senate; https://www.nap.edu/read/10840/chapter/8#234

Table 1. Summary of equipment and applicability of the four-factor analysis.

Unit	Equipment	NO_X (lb/hr)	NO_X (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 (lb/hr)	SO_2 (tpy)	SO_2 Subject to Analysis? (Yes/No)
C-01	Natural Gas Fired Two Stroke Lean-Burn Engines	53.6	36.9	Yes	0.0073	0.032	No
C-02	Natural Gas Fired Two Stroke Lean-Burn Engines	53.6	36.9	Yes	0.0073	0.032	No
C-03	Natural Gas Fired Two Stroke Lean-Burn Engines	53.6	36.9	Yes	0.0073	0.032	No
C-04	Natural Gas Fired Two Stroke Lean-Burn Engines	53.6	36.9	Yes	0.0073	0.032	No
C-05	Natural Gas Fired Two Stroke Lean-Burn Engines	53.6	36.9	Yes	0.0073	0.032	No
C-06	Natural Gas Fired Two Stroke Lean-Burn Engines	53.6	36.9	Yes	0.0073	0.032	No
C-07	Natural Gas Fired Two Stroke Lean-Burn Engines	53.6	36.9	Yes	0.0073	0.032	No
C-08[b]	Natural Gas Fired Two Stroke Lean-Burn Engines	53.6	36.9	Yes	0.0073	0.032	No
C-09[c]	Natural Gas Fired Two-Stroke Lean-Burn Engines	53.6	13.4	Yes	0.0073	0.002	No
C-10[c]	Natural Gas Fired Two Stroke Lean-Burn Engines	77.2	19.3	Yes	0.0088	0.002	No
C-11[c]	Natural Gas Fired Two Stroke Lean-Burn Engines	77.2	19.3	Yes	0.0088	0.002	No
C-12[c]	Natural Gas Fired Two Stroke Lean-Burn Engines	77.2	19.3	Yes	0.0088	0.002	No
C-13	Natural Gas Fired Two Stroke Lean-Burn	61.1	267.5	Yes	0.0124	0.054	No
B-01	Natural Gas Fired Boilers	20.6	90.0	Yes	0.067	0.29	No
B-02	Natural Gas Fired Boilers	20.6	90.0	Yes	0.067	0.29	No
AM-01/ F-01	Amine Gas Treating Unit [a]	-	-	No	5176.6	776.5	Yes

[a] This unit is controlled by an acid gas injection well during normal operations and a flare during SSM or malfunction activities. Hydrogen sulfide emissions from this unit are combusted to form sulfur dioxide at flare F-01.

[b] This unit is inoperable and therefore permanently shutdown. Targa intends to remove it from the NSR permit in its next permitting action. It is not further reviewed in this report but should be noted for emission reductions at the site.

[c] Units C-09 and C-12 were restricted to 500 hrs/yr operation in permit 67-M8R1 and C-10 and C-11 were restricted to 500 hr/yr operation in permit 67-M7.

Once the applicability of process equipment and pollutants has been determined, potential retrofit control technologies must be identified in accordance with 40 CFR 51 Appendix Y. At the recommendation of the NMED,[4] this is primarily achieved by utilizing RACT/BACT/LAER Clearinghouse (RBLC) data. In order to determine the most relevant and current retrofit controls available, the RBLC was queried for the two-stroke lean-burn engines over the past 20 years and the last ten years for the boilers. Summaries of the search results are provided and discussed in Section 2 of this report. The facility engineers then reviewed the list of available retrofit technologies and performed a technical feasibility assessment for each control option. The required four-factor analysis is then conducted for those controls that are technically feasible.

Targa has reduced NO_X emissions prior to this analysis but after the 2016 baseline date by reducing hours of operation on several units, replacing natural gas combustion units with electrically driven sources and removing units from service. Below is a summary the NO_X reduction from engines at the facility since 2016:

- Targa replaced unit C-15 (natural gas internal combustion engine) with three (3) screw compressors driven by electric motors in the 2019 NSR Permit 067-M9R2.
- Targa has also since reduced the operating hours on Unit C-09, C-10, C-11, and C-12 to 500 hours. These four units were replaced with compressors driven by electric motors in NSR permits 067-M8R1 and 067-M7.
- Targa has permanently shutdown Unit C-08 and Targa intends to remove it from the NSR permit in its next permitting action. It is not further reviewed in this report but should be noted for emission reductions at the site.

Targa conducted the required Four Factor Analysis for engines and boilers listed in Table 1 above. Based on a comprehensive review of the RBLC and control vendor's input of available control technologies, Targa determined the only feasible additional control option for natural gas fired two-stroke lean burn (2SLB) engines is installation of clean burn technology and the only feasible additional control option for boilers is flue gas recovery.

[4] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

2.1. SO_2 EMISSIONS

Targa controls H_2S emissions from the amine unit through operation of an acid gas injection (AGI) well at the site and is in the process of adding redundant electric compression to the AGI well system to further reduce SO_2 emissions during SSM and malfunction flaring events. The addition of the redundant electric compression is solely required by a Settlement Agreement and Stipulated Final Compliance Order between the Environmental Protection Division of the New Mexico Environment Department and Targa Midstream Services LLC. Targa expects this project to reduce SO_2 flaring emissions at Eunice Gas Plant by approximately 200-250 tons per year. The installation of the redundant compression constitutes effective emission control technology to meet emission reductions required under the Settlement Agreement. This project will be complete by December 31, 2020 and therefore occurs during the 2nd Planning Period.

There are no further control options for the amine unit. No further analysis should be necessary to evaluate SO_2 emissions from the amine treater since no additional control equipment can be added to reduce SO_2 emissions at the site. Therefore, Targa will not assess any further control technology for this process unit.

2.2. NO_X EMISSIONS

Eunice Gas Plant has twelve (12) natural gas-fired two-stroke lean-burn engines are subject to review under this analysis. There are also two (2) natural gas boilers that are subject to review under this analysis. The only pollutant subject to evaluation for these units is nitrogen oxides (NO_X). More detailed information on each engine and boiler units is listed in Table 2 below:

Table 2. Summary of equipment and applicability of the four-factor analysis.

Unit	Make & Model	Date of Manufacture	Permitted Capacity
C-01	Clark BA-8	Prior to 1972	1200 hp
C-02	Clark BA-8	Prior to 1972	1200 hp
C-03	Clark BA-8	Prior to 1972	1200 hp
C-04	Clark BA-8	Prior to 1972	1200 hp
C-05	Clark BA-8	Prior to 1972	1200 hp
C-06	Clark BA-8	Prior to 1972	1200 hp
C-07	Clark BA-8	Prior to 1972	1200 hp
C-09	Clark BA-8	Prior to 1972	1200 hp
C-10	Clark HBA-8	Prior to 1972	1600 hp
C-11	Clark HBA-8	Prior to 1972	1600 hp
C-12	Clark HBA-8	Prior to 1972	1600 hp
C-13	Clark HBA-T8	Prior to 1972	2050 hp
B-01	Wickes/Type A	Prior to 1972	100 MMBtu/hr
B-02	Wickes/Type A	Prior to 1972	100 MMBtu/hr

2.2.1. Two-Stroke Lean-Burn Engines

Table 3. Potential Control Equipment for Two-Stroke Lean-Burn RICE

Control Equipment	Technically Feasible?	NO_x Control Efficiency
Good Combustion Practices and Fuel Selection	**Yes**	**Base Case**
Clean Burn Technology	**Yes**	**70% to 90%**
Selective Catalytic Reduction	**No**	**N/A**
Non-Selective Catalytic Reduction	**No**	**N/A**

2.2.1.1. Two-Stroke Lean-Burn Engines Background

A reciprocating internal combustion engine (RICE) is a device that uses the combustion of fuel and air in an internal chamber to generate a reciprocating motion and convert heat energy into mechanical work. The units use a piston to draw air and fuel into the combustion chamber and compress it. The compressed air/fuel mixture

is then ignited, generating combustion in the chamber. The energy of combustion pushes out the piston, turning a crankshaft and producing mechanical work. In the same cycle, the products of combustion remaining in the chamber are released and exhausted from the unit.

Natural gas-fired RICE are separated into multiple design classes, including 2-stroke lean-burn (2SLB), 4-stroke lean-burn (4SLB), and 4-stroke rich-burn (4SRB). The four-stroke design uses four strokes of the piston, or two turns of the crankshaft, to complete the power cycle. The two-stroke design completes the power cycle in a single revolution of the crankshaft. Rich-burn engines are designed to operate close to the stoichiometric, or chemically balanced, air-to-fuel ratio (around 16:1) with exhaust oxygen levels less than 4%, while lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1), with exhaust oxygen levels of 12% or more.[5] .

NO_X is formed in reciprocating engines by the following mechanisms:

(1) Thermal NO_X - the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion,
(2) Fuel NO_X - the evolution and reaction of fuel-bound nitrogen compounds with oxygen, and
(3) Prompt NO_X - the early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The Eunice engines also use natural gas fuel; therefore, the formation of prompt NO_X and fuel NO_X will again be insignificant, and this analysis will focus on thermal NO_X. The rate of NO_X formation through the thermal NO_X mechanism is highly dependent upon the air-to-fuel ratio, combustion temperature, and residence time at the combustion temperature. Maximum thermal NO_X formation occurs near the stoichiometric air-to-fuel mixture ratio because combustion temperatures are greatest at this ratio[6].

NO_X reduction in natural gas-fired RICE can be accomplished by three general methods, as follows:[7]

(1) Operational control methods, such as adjusting the timing or other operating parameters.
(2) Combustion control techniques, for example reducing the peak flame temperature or introducing inerts that limit initial NO_X formation.
(3) Post-combustion NO_X control technologies, which employ various strategies to chemically reduce NO_X.

The potential to emit (PTE) from each engine is reported in the Eunice Gas Plant's NSR (0067M9R2) and Title V (P109-R2M1) permits as well as summarized in Table 1. Additionally, the NOx emission rates from the RICE are calculated using stack test data.

2.2.1.2. Potential NO_X Controls for 2SLB Engines

Retrofit control options identified for 2SLB RICE were identified via comprehensive review of the RBLC and available technical literature and are summarized in Table 3. A detailed description and discussion of the technical feasibility and anticipated performance of each control is provided below.

2.2.1.2.1 Good Combustion Practices and Fuel Selection

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's

[5] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
[6] Ibid.
[7] Ibid.

recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from large natural gas-fired lean-burn stationary internal combustion engines; therefore, it has been determined that this method of NO_X control is feasible for the 2SLB engines at Eunice Gas Plant. However, these practices are currently in use at Eunice Gas Plant. No further assessment of these control practices has been included in this report.

Eunice Gas Plant conducts routine maintenance on all engines at the site per manufacture recommendations using trained maintenance personnel and using pipeline quality natural gas.

2.2.1.2.2 Clean Burn Technology

Clean Burn Technology (CBT) is another term for utilizing combustion mixtures in engines with fuel-lean air-to-fuel ratios. This method of reducing NO_X emissions involves reconfiguring the engines by adding an air-to-fuel ratio controller so that they are capable of operating at more desirable ratios.

As described in Section 2.1.1 of this report, lean-burn engines operate at air-to-fuel ratios ranging from 20:1 to 50:1. A combustion mixture with a higher air-to-fuel ratio results in reduced NO_X emissions, because using fuel-lean mixtures lowers the combustion temperature by diluting energy input. 2SLB engines are typically designed to operate at the high air-to-fuel ratios employed in CBT; however, further increasing the air-to-fuel ratio in lean-burn engines can decrease the NO_X emissions.[8]

In order to avoid derating the engine, combustion air must be increased at constant fuel flow. To achieve this, the engine would need to be retrofitted with a turbocharger, which forces additional air into the combustion chamber, as well as an automatic air-to-fuel ratio controller.

Many 2SLB engines, such as naturally aspirated engines, do not have identical air-to-fuel ratios in each cylinder, which can result in limited ability to vary the air-to-fuel ratio. To maintain acceptable engine performance at lean conditions, high energy ignition systems (HEIS) have been developed that promote flame stability at very lean conditions.[9]

2SLB engines are mechanically capable of being retrofit with more sensitive air-to-fuel ratio controllers and running on higher air-to-fuel ratio combustion to control NO_X emissions. Therefore, it has been determined that this method of NO_X control is feasible for the 2SLB engines at Eunice. On 2SLB RICE, air-to-fuel ratio adjustment generally achieves a 5 to 30% reduction in NO_X emissions; however, this reduction is very specific to each engine and typical loading.[10]

Targa was able to request potential NO_X reduction options from their engine control vendor including Clean Burn technology. The Clean Burn technology will reduce NO_X emissions between 70% and 90%. The units could be modified to operate with pre-combustion chambers and pilot fuel systems with Jet Cells which are needed to

[8] State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines, State of New Jersey Department of Environmental Protection, 2003.
[9] Ibid.
[10] Ibid.

significantly lean the combustion mixture with the required capacity air source. The 2SLB engines will also need turbochargers or externally driven blowers added as well. If a 2SLB engine does need an externally driven blower, this will be an electric blower and require electricity to operate. At this time, Eunice Gas Plant would have to significantly upgrade the power substation at the plant to operate blowers associated with these controls. The cost provided in Section 3 of this report does not include the cost to upgrade the electrical substation at the facility. An engineering design assessment would need to be completed before a total cost for the upgrade can be provided but is estimated at $1 million to $3 million.

Even with the power concerns, Targa has determined that this method of NO_X control is feasible for the 2SLB engines at the facility.

2.2.1.2.3 Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[11] The chemical reactions for this process are shown in the equations below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

An SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and an electronic control system. The electronic controls regulate the quantity of reagent injected as a function of engine load, speed, and temperature, so NO_X emissions reductions can be achieved. The catalyst effectiveness can reduce over time and ultimately become inactive. This inactivity can be caused by the following: [12]

- Poisoning of the active sites by flue gas constituents;
- Thermal sintering of active sites due to high temperatures within the catalyst reactor;
- Blinding/plugging/fouling of active sites by ammonia-sulfur salts and particulate matter; and
- Erosion due to high gas velocities.

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as ammonia slip. Unreacted ammonia in the exhaust can form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams can blind the catalyst and may necessitate the application of a soot blower.[13]

For an SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 and 850 °F), the material of the catalyst will affect the specific temperature range the exhaust must operate within. Exhaust gas temperatures greater than the upper limit will cause the NO_X and ammonia to pass through the catalyst unreacted.[14]

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[11] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
[12] Ibid.
[13] Ibid.
[14] U.S. EPA, AP-42, Section 3.2, "Natural Gas-fired Reciprocating Engines"

In order for the chemical reactions necessary for SCR to occur effectively, the exhaust streams injected with the reagent must be fairly oxygen rich. The exhaust oxygen levels for 2SLB engines are sufficient to support these reactions; therefore, this technology can be used on lean-burn engines.

That said, the RBLC does not identify SCR as a control for these specific engine models.[15] This is likely because there is limited operating experience to date with the use of SCR on 2SLB RICE. Additionally, there is a historical precedent that installation of SCR on 2SLB engines can result in significant technical complications, including a necessity to derate the engines and unreliable operation post-retrofit.

The engine control vendors did not offer or suggest SCR as a suitable control option as there are significant challenges to install this equipment on the 2SLB units at Eunice. The main challenge is most 2SLB engines have a poor air-to-fuel ratio that will not support the SCR control. The vendors provided CBT technology as the technically feasible option to control NO_X emissions from 2SLB engines. As SCR control technology is not listed in the RBLC tables for 2SLB engines, has not been a proven as an effective control of NO_X emissions for 2SLB engines and has significant operating challenges for 2SLB engines, Targa has determined this control is technically infeasible.

2.2.1.2.4 Non-Selective Catalytic Reduction

Non-Selective Catalytic Reduction (NSCR) is a control technique that uses residual hydrocarbons and carbon monoxide (CO) in engine exhaust as a reducing agent for NO_X. In an NSCR system, hydrocarbons and CO are oxidized by oxygen (O_2) and NO_X. The excess hydrocarbons, CO, and NO_X pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H_2O and CO_2, while reducing NO_X to N_2.[16] This technique does not require additional reagents to be injected because the unburned hydrocarbons in the engine exhaust are used as the reductant. The chemical reactions for this process are shown in the equations below.[17]

Phase 1:
$$2CO + O_2 \rightarrow 2CO_2$$
$$2H_2 + O_2 \rightarrow 2H_2O$$
$$HC + O_2 \rightarrow CO_2 + H_2O$$

Phase 2:
$$NO_X + CO \rightarrow CO_2 + N_2$$
$$NO_X + H_2 \rightarrow H_2O + N_2$$
$$NO_X + HC \rightarrow CO_2 + H_2O + N_2$$

The reactions in Phase 1 of the chemical process above function to remove excess oxygen from the exhaust stream. This step is necessary because if the oxygen is not removed, it will react more readily with the CO and hydrocarbons than the NO_X, thus reducing the NO_X removal.

Despite this oxygen removal step in the chemical process, the engine exhaust gas stream must already have low levels of excess oxygen, or the oxygen will not be fully removed in Phase 1 and the NO_X removal will not be efficient. Consequently, application of the NSCR control technique is effectively limited to engines with normal exhaust oxygen levels of 4% or less. This includes naturally aspirated 4SRB engines and some turbocharged

[15] Ibid.
[16] Ibid.
[17] U.S. EPA, "Compliance Assurance Monitoring Technical Guidance Document", Appendix B Review Draft, 2005

4SRB engines. In order to achieve effective NO_X reduction performance, the engine may need to be run with a richer fuel adjustment than normal, resulting in an exhaust excess oxygen level closer to 1%.[18]

The exhaust oxygen levels for 2SLB engines are not sufficiently low to support the reactions described above; therefore, this technology is not a method used to control NO_X emissions from lean-burn engines. Furthermore, NSCR was not identified in the review of the RBLC as a potential control of NO_X emissions from large natural gas-fired lean-burn stationary RICE and AP-42 Section 3.2 does not list NSCR as an available control technique for 2SLB engines.[19] For these reasons, it has been determined that this method of NO_X control is infeasible for the 2SLB engines at Eunice.

2.2.2. Industrial Boilers

2.2.2.1. Industrial Boilers Background

Similar to natural gas engines, boilers have three NO_X formation mechanisms and both fuel and prompt NO_X formations are negligible for natural gas fired industrial boilers. Thermal NO_X results from the oxidation of atmospheric nitrogen in the high-temperature, post-flame region of a combustion system. The major factors that influence thermal NO_X formation are temperature, concentrations of oxygen and nitrogen, and residence time. If the temperature or the concentration of oxygen or nitrogen can be reduced quickly after combustion, thermal NO_X formation can be suppressed. This includes controlling the conditions within and immediately following the flame zone where most combustion reactions occur. In utility boilers, temperature, residence time, and turbulence are determined by factors associated with boiler and burner design, fuel characteristics, and boiler operating conditions.

2.2.2.2. Potential NO_X Controls for Industrial Boilers

The retrofit control equipment identified for industrial boilers during a comprehensive review of the RBLC are reported in Table 4Table 4. Potential Control Equipment for Industrial Boilers. A detailed discussion including a description, the technical feasibility, and the estimated performance of each control, is provided below.

Table 4. Potential Control Equipment for Industrial Boilers

Control Equipment	Technically Feasible	NO_X Control Efficiency
Good Combustion Practices	**Base Case**	**N/A**
Low NO_X	**Yes**	**N/A**
Flue Gas Recirculation	**Yes**	**45 ppm**
Selective Catalytic Reduction	**No**	**N/A**
Selective Non-Catalytic Reduction	**No**	**N/A**

[18] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
[19] Ibid.

2.2.2.2.1 Good Combustion Practices

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the combustion chamber where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, tuning of the boilers, as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from boilers; therefore, it has been determined that this method of NO_X control is feasible for the units at Eunice. However, these practices are currently in use at Eunice, as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices has been included in this report.

2.2.2.2.2 Low NO_X Burner

The low NO_X (LN) burner control, seeks to reduce the combustion temperature and residence time of fuel in the combustor (thereby decreasing NO_X formation) by increasing the air-to-fuel ratio in the combustion chamber. This is usually accomplished by staging techniques that supply excess air to cool the combustion process (fuel-lean combustion zone) and by reducing the concentration of oxygen in the flame zone (fuel-rich combustion zone). There are several levels of improvements that can be made to the combustion chamber, which achieve this NO_X control at varying levels. NO_X emission reductions of 40% to 85% have been observed with low NO_X burners. [20]

Targa has determined that this method of NO_X control is feasible for the boilers at the facility. The boilers at Eunice already have LN burners installed. The next step of control for the burners is to replace the current burners with ultra-low NO_X (ULN) burners. The vender for the boilers stated that it will be technically infeasible to run the boilers at times with the ULN burners because the fuel gas for the boilers is rich (i.e. has a higher Btu content). Due to the age of the boilers and the venders concerns with the fuel, Targa considers adding the ULN burners technically infeasible, as the boilers will not be able to operate under current conditions. No further assessment of these control practices has been included in this report.

2.2.2.2.3 Flue Gas Recirculation

In a Flue Gas Recirculation (FGR) system, a portion of the flue gas is recycled from the stack to the burner or combustion zone. Upon entering the wind box, the recirculated gas is mixed with combustion air prior to being fed into the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NO_X emissions by two mechanisms. Primarily, the recirculated gas acts as a diluent to reduce combustion temperatures, thus suppressing the thermal NO_X formation mechanism. To a lesser extent, FGR also reduces NO_X formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is a key operating parameter influencing NO_X emission reduction potential for these systems.

Targa has determined that this method of NO_X control is technically feasible for the boilers at the facility.

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[20] U.S. EPA, AP-42, Section 1.4, "Natural Gas Combustion"

2.2.2.2.4 Selective Catalytic Reduction

The selective catalytic reduction (SCR) system for industrial boilers is similar to the process explained in Section 2.1.2.3 and involves injecting ammonia (NH_3) into the flue gas in the presence of a catalyst to reduce NOx emissions. The Alternative Control Techniques (ACT) document for utility boilers estimates NO_X reduction efficiencies for SCR control ranging from 70% to 90%.[21], [22] Historically, retrofitting SCR controls on boilers is difficult and affects the reliability of the boilers.[23] Additionally, SCR controls have significant electrical power requirements. The power at the plant would need to be upgraded significantly and re-designed in order to provide the necessary power for SCR controls. Therefore, SCR controls are considered a technically infeasible control option for the boilers located at Eunice and are not assessed further in this report.

2.2.2.2.5 Selective Non-Catalytic Reduction

The selective non-catalytic reduction (SNCR) system for industrial boilers is a chemical reaction that will reduce NO_X emissions by the NO_X reacting with a reagent, such as ammonia or urea, to create nitrogen and water. This reaction only takes place during a very specific temperature range of 1600 °F and 2100 °F. If the reaction takes place outside this temperature range, the NO_X reaction will not be favored.[24] The reagent is injected into the combustion chamber to promote the mixing of the reagent with the flue gas. The process of where and how the injection will happen depends on the specific boiler model and operation. The disadvantages to this control system is the specific operating temperature in which the reaction to reduce NO_X occurs. Low-loads will especially affect the temperature profile and optimum operating temperature of the control. Due to the specific operating parameters including temperature of the boilers at Eunice, Targa has deemed this control option as technically infeasible and will not assess it any further in this report.

[21] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

[22] U.S. EPA, AP-42, Section 1.4, "Natural Gas Combustion"

[23] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

[24] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet -- Selective Non-Catalytic Reduction (SNCR)" EPA-452/F-03-031

3. COST OF COMPLIANCE

According to the EPA Control Cost Manual, there are five steps associated with evaluating the control cost effectiveness:

1. Obtain the facility parameters and regulatory options for a given facility;
2. Draft the control system design;
3. Size the control system components;
4. Estimate the costs of these individual components; and
5. Estimate the capital and annual costs of the entire system.

The cost effectiveness discussion and summary tables for the engines and boilers applicable to this analysis are provided in this section. Detailed cost control estimates are provided in Appendix B.

3.1. TWO-STROKE LEAN-BURN ENGINE CONTROLS

Table 5. Cost analysis summary of technically feasible controls for two-stroke lean-burn engines.

Control Equipment	Unit	Capital Cost ($)	Total Annual Cost ($)[a, b]	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Clean Burn Technology	C-01	**950,000[c]**	**179,495**	**118.28**	**1,517.53**
	C-02	**950,000[c]**	**179,495**	**40.82**	**4,396.91**
	C-03	**950,000[c]**	**179,495**	**30.12**	**5,959.33**
	C-04	**950,000[c]**	**179,495**	**77.27**	**2,323.09**
	C-05	**950,000[c]**	**179,495**	**74.04**	**2,424.14**
	C-06	**950,000[c]**	**179,495**	**121.00**	**1,483.48**
	C-07	**950,000[c]**	**179,495**	**100.97**	**1,777.73**
	C-09	**950,000[c]**	**179,495**	**10.09**	**17,797.69**
	C-10	**950,000[c]**	**179,495**	**8.29**	**21,651.71**
	C-11	**950,000[c]**	**179,495**	**12.58**	**14,269.03**
	C-12	**950,000[c]**	**179,495**	**6.91**	**25,969.35**
	C-13	**950,000[c]**	**179,495**	**199.09**	**901.58**

[a] Total Annual Cost includes the annualized capital cost, as well as the direct and indirect annual operating costs.

[b] This cost does not include annual operating costs for upgrade to the electrical substation that would incur. A full engineering assessment would need to be completed in order to know the full annual cost of this upgrade.

[c] The Capital Cost does not include the $1 million to $3 million required to upgrade the electrical substation at the site needed to power blowers for the CTB technology. A full engineering assessment would need to be completed in order to know the full cost of this upgrade.

3.1.1. Good Combustion Practices and Fuel Selection

Targa already employs good combustion practices and fuel selection. There is no further cost to assess for this control technology.

3.1.2. Clean Burn Technology

Targa has received an estimated direct capital costs for the equipment and vendor labor associated with implementing a CBT on the 2SLB models located at Eunice from the engine control vendor. Based on prior knowledge of the equipment, Targa estimated the direct annual costs (maintenance, operating labor, reagent cost, electricity cost, and catalyst cost) and indirect annual costs associated with Targa's internal labor, overhead and capital recovery for the project. Please note that the cost in Table 5 does not include the significant upgrade to the power substation at the plant to operate the blowers associated with these CTB controls as discussed in Section 2.2.12.2. The upgrade to the substation would require a Capital Cost of at least $1 million to $3 million. A full engineering design assessment would need to be completed before a final full cost can be provided.

This cost estimate assumes that the CBT will reduce NO_X emissions to an outlet concentration of 2 g/hp-hr, based on information provided by the engine control vender. The cost effectiveness for each engine control option are summarized in Table 5. The full cost estimation for each unit is included in Appendix B of this report. To calculate the emission reductions, Targa used the 2016 Emission Inventory (EI) data. This was compared to the maximum PTE emission rate of the equipment post-control to get an Emission Reduction (tpy) value. The Total Annual Cost was then divided by the Emission Reduction to come up with a Cost Effectiveness ($/ton) amount. Please note that since 2016, engines C-09, C-10, C-11, and C-12 are now operated as standby, backup units. They were replaced with electric driven compressors. Targa revised the emission limits for these engines reducing their annual operation to a maximum of 500 hours per year for each engine. Therefore, the 2016 emission inventory rates were reduced to a maximum of 500 hours per year for these engines multiplied by the emission rate of the unit used in the 2016 EI.

3.2. INDUSTRIAL BOILER CONTROLS

Cost effectiveness for each engine control option are summarized in Table 6.

Table 6. Cost Analysis Summary of Technically Feasible Controls for Industrial Boilers.

Control Equipment		Capital Cost ($)	Total Annual Cost ($)*	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Flue Gas Recirculation	B-01	**300,000**	**39,104**	**2.42**	**16,138.92**
	B-02	**300,000**	**39,104**	**2.02**	**19,371.44**

*Total Annual Cost includes the annualized capital cost, as well as the direct and indirect annual operating costs.

3.2.1. Good Combustion Practices and Fuel Selection

Targa already employs good combustion practices and fuel selection. There is no further costs to asses for this control technology.

3.2.2. Low NO_X Burner

Targa has already employed LN burners on the boilers. There is no further costs to asses for this control technology.

3.2.3. Flue Gas Recirculation

Targa has received an estimated direct capital costs for the equipment and vendor labor associated with implementing a FGR on the boilers located at Eunice from the control vendor. Based on prior knowledge of the equipment, Targa estimated the direct annual costs (maintenance, operating labor, reagent cost, electricity cost, and catalyst cost) and indirect annual costs associated with Targa's internal labor, overhead and capital recovery for the project.

This cost estimate assumes that the FGR will reduce NO_X emissions to an outlet concentration of 45 ppm. The cost effectiveness for each engine control option are summarized in Table 4. To calculate the emission reductions, Targa used the 2016 Emission Inventory (EI) data. This was compared to the maximum PTE

emission rate of the equipment post-control to get an Emission Reduction (tpy) value. The Total Annual Cost was then divided by the Emission Reduction to come up with a Cost Effectiveness ($/ton) amount. The full cost estimation for each unit is included in Appendix B of this report.

4.1. TWO-STROKE LEAN-BURN ENGINE CONTROLS

4.1.1. Good Combustion Practices and Fuel Selection

Targa already employs good combustion practices and fuel selection. There is no further time for compliance to assess for this control technology.

4.1.2. Clean Burn Technology

Targa estimates that approximately 7 years will be needed to budget, design, procure, permit, and install the CBT equipment from the time the facility is required to add this control.

4.2. INDUSTRIAL BOILERS

4.2.1. Good Combustion Practices and Fuel Selection

Targa already employs good combustion practices and fuel selection. There is no further time for compliance to assess for this control technology.

4.2.2. Low NO_X Burners

Targa already employs LN burners. There is no further time for compliance to assess for this control technology.

4.2.3. Flue Gas Recirculation

Targa estimates that approximately 5 years will be needed to budget, design, procure, permit, and install, the FGR control equipment from the time the facility is required to add this control.

5.1. TWO-STROKE LEAN-BURN ENGINES

5.1.1. Good Combustion Practices and Fuel Selection

There are no anticipated unique or site-specific energy or non-air impacts imposed by continuing to use good combustion practices and fuel selection.

5.1.2. Clean Burn Technology

Clean burn technology control employs a combustion mixture with a higher air-to-fuel ratio, because using fuel-lean mixtures lowers the combustion temperature by diluting energy input. This will reduce NO_X emissions; however, a reduction in combustion temperature increases emissions of CO, due to incomplete combustion. The blowers associated with this control will require electrical power to operate. This additional power will cause additional strain on the electrical grid and require an upgrade to the electrical substation at the site.

5.2. INDUSTRIAL BOILERS

5.2.1. Good Combustion Practices and Fuel Selection

There are no anticipated unique or site-specific energy or non-air impacts imposed by continuing to use good combustion practices and fuel selection.

5.2.2. Low NOX Burner

There are no anticipated unique or site-specific energy or non-air impacts imposed by continuing to use LN burners.

5.2.3. Flue Gas Recirculation

There are no anticipated unique or site-specific energy or non-air impacts imposed by installing FGR.

6.1. TWO-STROKE LEAN-BURN ENGINE CONTROLS

6.1.1. Good Combustion Practices and Fuel Selection

Targa already employs good combustion practices and fuel selection. No further information needs to be assessed in this section.

6.1.2. Clean Burn Technology

The estimated useful life of the CTB equipment is 20 years, based on industry standards for life of the controls.

6.2. INDUSTRIAL BOILERS

6.2.1. Good Combustion Practices and Fuel Selection

Targa already employs good combustion practices and fuel selection. No further information needs to be assessed in this section.

6.2.2. Low NO_X Burners

Targa already employs LN burners. No further information needs to be assessed in this section.

6.2.3. Flue Gas Recirculation

The estimated useful life of the FGR equipment is 20 years, based on default values from the EPA Air Pollution Control Cost Manual.[25]

[25] Ibid.

7. RESULTS & CONCLUSION

Based on a comprehensive review of the RBLC, and engine control vendor's input of available control technologies for the natural-gas fired engines and boilers located at Eunice Gas Plant, Targa has determined that CBT and good combustion practices for the 2SLB engines and flue gas recovery for the boilers are the only technically feasible NO_X control options for the units being reviewed under this analysis. However, retrofitting with these technologies would require Targa to spend significant amounts of time (for design and installation) and capital. In addition, based on the predominant wind direction and that SO_2, not NOx, is the contaminant of interest for visibility impairment in Carlsbad Caverns, NOx emissions from these pieces of equipment are inconsequential for regional haze purposes. Thus, retrofitting the Eunice Gas Plant engines or boilers would be uneconomical and unnecessary for improving visibility.

APPENDIX A: RBLC TABLES

Attached are the RBLC tables, Table A-1 for the 2SLB Clark engines and Table A-2 for the natural gas boilers.

Table A-1. 2SLB Clark Engines RBLC Tables.

RBLCID	FACILITY_NAME	PROCESS_NAME	THROUGHPUT		POLLUTANT	CONTROL_METHOD_DESCRIPTION
NE-0015	KN ENERGY. INC	IC ENGINE, 2511E, COOPER GMVA-6	750	HP	Nitrogen Oxides (NOx)	
NE-0015	KN ENERGY. INC	IC ENGINE, 2512E, CLIMAX V-125	320	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, 2514E, INGERSOLL RAND SVG-12	660	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, 2515E, WAUKESHA L3711	285	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, 2516E, WAUKESHA L3711	285	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	TURBINE, 2551E, SOLAR SATURN	1100	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS.
NE-0015	KN ENERGY. INC	2-CYCLE LEAN BURN ENGINE, UNIT 2505E	1000	HP	Nitrogen Oxides (NOx)	2ND GENERATION CLEAN BURN CONTROL.
NE-0015	KN ENERGY. INC	IC ENGINE, 2506E	2200	HP	Nitrogen Oxides (NOx)	2ND GENERATION CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	TURBINE, 2507E, SOLAR T-1001	1100	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	TURBINE, 2508E, SOLAR CENTAR	4756	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS.
NE-0015	KN ENERGY. INC	IC ENGINE, 2503E, COOPER GMVA-10	1265	HP	Nitrogen Oxides (NOx)	CLEAN BURNCONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, 2504E, COOPER GMVA-6	750	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, CLEAN BURN, 2517E COOPER GMVH-8	2000	HP	Nitrogen Oxides (NOx)	2ND GENERATION CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, (2), 2501E & 2502E CLARK RA-6	565	HP	Nitrogen Oxides (NOx)	2ND GENERATION CLEAN BURN CONTROLS
TX-0364	SALT CREEK GAS PLANT	(2) INGERSOLL-RAND ENGINES, #IR-SVG-8, EPN4&5	440	HP	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	HOT OIL HEATER, EPN6	12	MMBTU/H	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	(2) INGERSOLL-RAND ENGINES, #IR-SVG-8, EPN10A&B	1330	HP	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	GLYCOL REBOILER, EPN11	2.5	MMBTU/H	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	(3) COOPER-BESSEMER ENGINES, #GMVH-12C2, EPN21-23	3105	HP	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	HOT OIL HEATER, EPN26	32.5	MMBTU/H	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	(2) FLARES, EPN 9 & 29			Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	HP TEG FIREBOX, EPN30	3	MMBTU/H	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	COOPER-BESSEMER ENGINE, #GMVH-12, EPN1	2400	HP	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	(2) CLARK ENGINE, #TLAB-6, EPN2&3	2000	HP EACH	Nitrogen Oxides (NOx)	NONE INDICATED

Table A-2. Industrial Boilers RBLC Tables.

RBLCID	FACILITY_NAME	THROUGHPUT	POLLUTANT	CONTROL_METHOD_DESCRIPTION
AK-0071	INTERNATIONAL STATION POWER PLANT	140 MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction
AK-0073	INTERNATIONAL STATION POWER PLANT	140 MMBTU/H	Nitrogen Oxides (NOx)	Duct Burners EU IDs 9 through 12 shall be equipped with Selective Catalytic Reduction (SCR). SCR is a post-combustion gas treatment technique for reduction of nitric oxide (NO) and nitrogen dioxide (NO2) in the turbine exhaust stream to molecular nitrogen, water, and oxygen. This process is accomplished by using ammonia (NH3) as a reducing agent, and is injected into the flue gas upstream of the catalyst bed. By lowering the activation energy of the NOx decomposition removal efficiency of 80 to 90 percent are achievable.
AK-0083	KENAI NITROGEN OPERATIONS	243 MMBTU/H	Nitrogen Oxides (NOx)	Ultra Low NOx Burners
AK-0083	KENAI NITROGEN OPERATIONS	101 MMBTU/H	Nitrogen Oxides (NOx)	Limited Use (200 hr/yr)
AR-0121	EL DORADO CHEMICAL COMPANY	240 MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS AND FLUE GAS RECIRCULATION
AR-0140	BIG RIVER STEEL LLC	234 MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES
CA-1206	STOCKTON COGEN COMPANY	178 MMBTU/H	Nitrogen Oxides (NOx)	
CA-1212	PALMDALE HYBRID POWER PROJECT	110 MMBTU/H	Nitrogen Oxides (NOx)	
IA-0105	IOWA FERTILIZER COMPANY	110.12 MMBTU/H	Nitrogen Oxides (NOx)	good combustion practices
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	250 MMBTU/H	Nitrogen Oxides (NOx)	LOW-NOX BURNER AND FGR
IL-0114	CRONUS CHEMICALS, LLC	104 MMBTU/H	Nitrogen Oxides (NOx)	low-nox burners
IN-0179	OHIO VALLEY RESOURCES, LLC	218 MMBTU/HR, E	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS FLUE GAS RECIRCULATION
IN-0263	MIDWEST FERTILIZER COMPANY LLC	218.6 MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES
LA-0244	LAKE CHARLES CHEMICAL COMPLEX - LAB UNIT	170 MMBTU/H	Nitrogen Oxides (NOx)	low nox burners

Table A-2. Industrial Boilers RBLC Tables.

RBLCID	FACILITY_NAME	THROUGHPUT	POLLUTANT	CONTROL_METHOD_DESCRIPTION
LA-0272	AMMONIA PRODUCTION FACILITY	217.5 MM BTU/HR	Nitrogen Oxides (NOx)	FLUE GAS RECIRCULATION, LOW NOX BURNERS, AND GOOD COMBUSTION PRACTICES (I.E., PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE).
LA-0307	MAGNOLIA LNG FACILITY	171 mm btu/hr	Nitrogen Oxides (NOx)	Low Nox burners
LA-0314	INDORAMA LAKE CHARLES FACILITY	248 mm btu/hr (ea	Nitrogen Oxides (NOx)	good combustion practices; fueled by natural gas or process fuel gas; ULNB (FGR and economizer)
LA-0314	INDORAMA LAKE CHARLES FACILITY	229 mm btu	Nitrogen Oxides (NOx)	good combustion practices; fueled by natural gas or process fuel gas; ULNB (FGR and economizer)
LA-0331	CALCASIEU PASS LNG PROJECT	115 MM BTU/h	Nitrogen Oxides (NOx)	Ultra Low NOx Burners and Good Combustion Practices
MI-0389	KARN WEADOCK GENERATING COMPLEX	220 MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER
MI-0423	INDECK NILES, LLC	182 MMBTU/H	Nitrogen Oxides (NOx)	Low NOx burners/Flue gas recirculation and good combustion practices.
MI-0427	FILER CITY STATION	182 MMBTU/H	Nitrogen Oxides (NOx)	LNB that incorporate internal (within the burner) FGR and good combustion practices.
NM-0052	ZIA II GAS PLANT	114 mmBtu/hr	Nitrogen Oxides (NOx)	
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	150 MMBTU/H	Nitrogen Oxides (NOx)	
OH-0354	KRATON POLYMERS U.S. LLC	249 MMBtu/H	Nitrogen Oxides (NOx)	Low-NOx burners
OH-0363	NTE OHIO, LLC	150 MMBTU/H	Nitrogen Oxides (NOx)	Ultra low NOx burner
OH-0374	GUERNSEY POWER STATION LLC	185 MMBTU/H	Nitrogen Oxides (NOx)	low-NOx burners and flue gas recirculation
OH-0379	PETMIN USA INCORPORATED	218.9 MMBTU/H	Nitrogen Oxides (NOx)	Low NOX burners, use of natural gas and good combustion practices
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	1052 MMscf/yr	Nitrogen Oxides (NOx)	Good combustion practices and ULNOx burners
TN-0162	JOHNSONVILLE COGENERATION	450 MMBtu/hr	Nitrogen Oxides (NOx)	Good combustion design and practices, selective catalytic reduction (SCR), low-NOX burners with flue gas recirculation
*TN-0164	TVA - JOHNSONVILLE COGENERATION	450 MMBtu/hr, ea	Nitrogen Oxides (NOx)	SCR, low-NOX burners, flue gas recirculation, good combustion design & practices
TX-0641	PINECREST ENERGY CENTER	150 MMBTU/H	Nitrogen Oxides (NOx)	low NOx burners

Table A-2. Industrial Boilers RBLC Tables.

RBLCID	FACILITY_NAME	THROUGHPUT	POLLUTANT	CONTROL_METHOD_DESCRIPTION
TX-0678	FREEPORT LNG PRETREATMENT FACILITY	130 MMBTU/H	Nitrogen Oxides (NOx)	ultra-low NOx burners
TX-0682	GALENA PARK TERMINAL	129 MMBTU/H	Nitrogen Oxides (NOx)	low-NOx burners and SCR
TX-0708	LA PALOMA ENERGY CENTER	150 MMBTU/H	Nitrogen Oxides (NOx)	low-NOx burners, limited use
TX-0712	TRINIDAD GENERATING FACILITY	110 MMBTU/H	Nitrogen Oxides (NOx)	ultra-low NOx burners, limited use
TX-0811	LINEAR ALPHA OLEFINS PLANT	217 MM BTU / H	Nitrogen Oxides (NOx)	Low-NOX burners and Selective Catalytic Reduction (SCR). Ammonia slip limited to 10 ppmv (corrected to 3% O2) on a 1-hr block average.
VA-0325	GREENSVILLE POWER STATION	185 MMBTU/HR	Nitrogen Oxides (NOx)	ultra low-NOâ€ž burners
VA-0328	C4GT, LLC	902 mmcf/y	Nitrogen Oxides (NOx)	Low NOx burners
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	100 mmBtu/hr	Nitrogen Oxides (NOx)	Ultra Low-NOx Burners, Flue-Gas Recirculation, & Good Combustion Practices

APPENDIX B: COST ANALYSIS SUPPORTING INFORMATION

The cost analysis was based on information received from engine or boiler control vendors or knowledge on the particular equipment and is provided in Table B-1 below.

Table B-1. Engine and Boiler Cost Information.

Equipment	Model	Control Type	Purchased Equipment Cost [a] ($)	Direct & Indirect Installation Cost [b] ($)	Capital Cost ($)
Clark	BA-8	CBT	800,000	150,000	950,000
Clark	HBA-8	CBT	800,000	150,000	950,000
Clark	HBA-T8	CBT	800,000	150,000	950,000
Wicker	Type A	Flue Gas Recirculation	300,000	*	300,000

[a] The cost in this column is based on a control vendor estimated quote. This cost does not include the $1 million to $3 million required to upgrade the electrical substation at the site needed to power blowers for the CTB technology. A full engineering assessment would need to be completed in order to know the full cost of this upgrade.

[b] The cost in this column is based on Targa's knowledge of the equipment but does not include the additional costs of operating the upgraded electrical substation.

*The flue gas recirculation control includes piping in the cost and modifications to the facility which is accounted for under purchased equipment.

Targa Eunice Gas Processing Plant

Eunice Gas Plant

Boiler	Interest Rate:	5.50%	
Unit B-01	Period (yrs):	20	<-- EPA Guidance Default

Base Emissions (CEMS)			
NO_X ppm	90	ppm	<-- From client
NO_X lb/hr:	1.84	lb/hr	<-- From 2016 EI calculations
NO_X tpy:	8.08	tpy	<-- From 2016 EI calculations

Flue Gas Recirculation				
NO_X control:		50%	Control Eff.	<-- Manufacturer estimate
NO_X ppm		45.00	ppm	
NO_X tpy:		4.04	tpy	
Total Cap Investment	$	300,000		<--Client provided
Annualized TCI:	$	25,104		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	14,000		<--Client Provided
Total Annual Costs:	$	39,104		
Emissions Reduction:		2.42	tpy	
Cost Effectiveness:	**$**	**16,138.92**	**$/ton**	

Targa Eunice Gas Processing Plant

Eunice Gas Plant

Boiler	Interest Rate:	5.50%	
Unit B-02	Period (yrs):	20	<-- EPA Guidance Default

Base Emissions (CEMS)			
NO_X ppm	90	ppm	<-- From client
NO_X lb/hr:	1.54	lb/hr	<-- From 2016 EI calculations
NO_X tpy:	6.73	tpy	<-- From 2016 EI calculations

Flue Gas Recirculation			
NO_X control:	50%	Control Eff.	<-- Manufacturer estimate
NO_X ppm	45.00	ppm	
NO_X tpy:	3.36	tpy	
Total Cap Investment	$ 300,000		<--Client provided
Annualized TCI:	$ 25,104		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 14,000		<--Client provided
Total Annual Costs:	$ 39,104		
Emissions Reduction:	2.02	tpy	
Cost Effectiveness:	**$ 19,371.44**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:	5.50%	
Units: C-01	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1200	hp	<-- As permitted
2016 Operating Hours	8009	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	13.165	g/hp-hr	<-- From 7/22/15 performance test
NO_X lb/hr:	34.83	lb/hr	<-- Calculated
NO_X tpy:	139.47	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		84.8%	Control Eff.	<-- Calculated ($NO_{X(in)}$ - $NO_{X(out)}$)/$NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Based on assumptions from manufactur
NO_X lb/hr:		5.29	lb/hr	
NO_X tpy:		21.19	tpy	
Total Cap Investment	$	950,000		<--Manufacturer specification
Annualized TCI:	$	79,495		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	179,495		
Emissions Reduction:		118.28	tpy	
Cost Effectiveness:	**$**	**1,517.53**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:	5.50%	
Units: C-02	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1200	hp	<-- As permitted
2016 Operating Hours	4271	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	9.226	g/hp-hr	<-- From 7/22/15 performance test
NO_X lb/hr:	24.41	lb/hr	<-- Calculated
NO_X tpy:	52.12	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		78.3%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		5.29	lb/hr	
NO_X tpy:		11.30	tpy	
Total Cap Investment	$	950,000		<--Manufacturer specification
Annualized TCI:	$	79,495		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	179,495		
Emissions Reduction:		40.82	tpy	
Cost Effectiveness:	**$**	**4,396.91**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:	5.50%	
Units: C-03	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1200	hp	<-- As permitted
2016 Operating Hours	7275	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	5.13	g/hp-hr	<-- From client
NO_X lb/hr:	13.57	lb/hr	<-- Calculated
NO_X tpy:	49.37	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		61.0%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		5.29	lb/hr	
NO_X tpy:		19.25	tpy	
Total Cap Investment	$	950,000		<--Manufacturer specification
Annualized TCI:	$	79,495		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	179,495		
Emissions Reduction:		30.12	tpy	
Cost Effectiveness:	**$**	**5,959.33**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:	5.50%	
Units: C-04	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1200	hp	<-- As permitted
2016 Operating Hours	5996	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	11.742	g/hp-hr	<-- From 7/23/15 performance test
NO_X lb/hr:	31.06	lb/hr	<-- Calculated
NO_X tpy:	93.13	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		83.0%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		5.29	lb/hr	
NO_X tpy:		15.86	tpy	
Total Cap Investment	$	950,000		<--Manufacturer specification
Annualized TCI:	$	79,495		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	179,495		
Emissions Reduction:		77.27	tpy	
Cost Effectiveness:	**$**	**2,323.09**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:	5.50%	
Units: C-05	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1200	hp	<-- As permitted
2016 Operating Hours	7684	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	9.285	g/hp-hr	<-- From 7/23/15 performance test
NO_X lb/hr:	24.56	lb/hr	<-- Calculated
NO_X tpy:	94.37	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		78.5%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		5.29	lb/hr	
NO_X tpy:		20.33	tpy	
Total Cap Investment	$	950,000		<--Manufacturer specification
Annualized TCI:	$	79,495		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	179,495		
Emissions Reduction:		74.04	tpy	
Cost Effectiveness:	**$**	**2,424.14**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:	5.50%	
Units: C-06	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1200	hp	<-- As permitted
2016 Operating Hours	8123	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	13.261	g/hp-hr	<-- From 7/23/15 performance test
NO_X lb/hr:	35.08	lb/hr	<-- Calculated
NO_X tpy:	142.49	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		84.9%	Control Eff.	<-- Calculated ($NO_{X(in)}$ - $NO_{X(out)}$)/$NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		5.29	lb/hr	
NO_X tpy:		21.49	tpy	
Total Cap Investment	$	950,000		<--Manufacturer specification
Annualized TCI:	$	79,495		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	179,495		
Emissions Reduction:		121.00	tpy	
Cost Effectiveness:	**$**	**1,483.48**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:	5.50%	
Units: C-07	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1200	hp	<-- As permitted
2016 Operating Hours	6476	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	13.787	g/hp-hr	<-- From 7/27/15 performance test
NO_X lb/hr:	36.47	lb/hr	<-- Calculated
NO_X tpy:	118.10	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		85.5%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		5.29	lb/hr	
NO_X tpy:		17.13	tpy	
Total Cap Investment	$	950,000		<--Manufacturer specification
Annualized TCI:	$	79,495		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	179,495		
Emissions Reduction:		100.97	tpy	
Cost Effectiveness:	**$**	**1,777.73**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:	5.50%	
Units: C-09	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1200	hp	<-- As permitted
2016 Operating Hours	500	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	17.249	g/hp-hr	<-- From 7/28/15 performance test
NO_X lb/hr:	45.63	lb/hr	<-- Calculated
NO_X tpy:	11.41	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		88.4%	Control Eff.	<-- Calculated ($NO_{X(in)}$ - $NO_{X(out)}$)/$NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		5.29	lb/hr	
NO_X tpy:		1.32	tpy	
Total Cap Investment	$	950,000		<--Manufacturer specification
Annualized TCI:	$	79,495		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	179,495		
Emissions Reduction:		10.09	tpy	
Cost Effectiveness:	**$**	**17,797.69**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark HBA-8	Interest Rate:	5.50%	
Units: C-10	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1600	hp	<-- As permitted
2016 Operating Hours	500	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	11.401	g/hp-hr	<-- From 7/28/15 performance test
NO_X lb/hr:	40.22	lb/hr	<-- Calculated
NO_X tpy:	10.05	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		82.5%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		7.05	lb/hr	
NO_X tpy:		1.76	tpy	
Total Cap Investment	$	950,000		<--Manufacturer specification
Annualized TCI:	$	79,495		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	179,495		
Emissions Reduction:		8.29	tpy	
Cost Effectiveness:	**$**	**21,651.71**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark HBA-8	Interest Rate:	5.50%	
Units: C-11	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1600	hp	<-- As permitted
2016 Operating Hours	500	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	16.265	g/hp-hr	<-- From 7/28/15 performance test
NO_X lb/hr:	57.37	lb/hr	<-- Calculated
NO_X tpy:	14.34	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		87.7%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		7.05	lb/hr	
NO_X tpy:		1.76	tpy	
Total Cap Investment	$	950,000		<--Manufacturer specification
Annualized TCI:	$	79,495		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	179,495		
Emissions Reduction:		12.58	tpy	
Cost Effectiveness:	**$**	**14,269.03**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark HBA-8	Interest Rate:	5.50%	
Units: C-12	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1600	hp	<-- As permitted
2016 Operating Hours	500	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	9.838	g/hp-hr	<-- From 7/29/15 performance test
NO_X lb/hr:	34.70	lb/hr	<-- Calculated
NO_X tpy:	8.68	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		79.7%	Control Eff.	<-- Calculated ($NO_{X(in)}$ - $NO_{X(out)}$)/$NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		7.05	lb/hr	
NO_X tpy:		1.76	tpy	
Total Cap Investment	$	950,000		<--Manufacturer specification
Annualized TCI:	$	79,495		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	179,495		
Emissions Reduction:		6.91	tpy	
Cost Effectiveness:	**$**	**25,969.35**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark HBA-T8	Interest Rate:	5.50%	
Units: C-13	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	2050	hp	<-- As permitted
2016 Operating Hours	7560	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	13.654	g/hp-hr	<-- From 7/29/15 performance test
NO_X lb/hr:	61.71	lb/hr	<-- Calculated
NO_X tpy:	233.26	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		85.4%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		9.04	lb/hr	
NO_X tpy:		34.17	tpy	
Total Cap Investment	$	950,000		<--Manufacturer specification
Annualized TCI:	$	79,495		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	179,495		
Emissions Reduction:		199.09	tpy	
Cost Effectiveness:	**$**	**901.58**	**$/ton**	

REGIONAL HAZE FOUR-FACTOR ANALYSIS
SSM FLARING ADDENDUM

Targa Midstream Services LLC – Eunice Gas Plant



SSM FLARING ADDENDUM

Targa appends the Four-Factor Analysis for Eunice Gas Plant with the following additional information on process and SSM flaring at our Eunice Gas Plant as requested in Liz Bisbey-Kuehn's November 14, 2019 emailed letter titled "Submittal Requirements for Process Flaring and Startup, Shutdown, and Maintenance (SSM) Flaring as part of the Regional Haze Four-Factor Analyses".

In Targa's original Four-Factor Analysis report submitted on October 31, 2019, flaring associated with F-01, Acid Gas Flare, was discussed in Section 1.1.2. As such, we do not intend to include additional information about this flaring. Targa maintains that the redundant compression unit to be installed by December 30, 2020 constitutes effective emission control technology to meet emission reductions required under the Settlement Agreement and therefore, does not require additional review.

Table 1A below shows the flare emission rates permitted in the current NSR permit for Eunice Gas Plant.

Table 1A. Summary of Flaring Emissions at Eunice Gas Plant.

Unit	Equipment	NO_X (lb/hr)	NO_X (tpy)	SO_2 (lb/hr)	SO_2 (tpy)
F-01	Acid Gas Flare (Allowable Emissions)	0.3	0.12	--	--
F-01	Acid Gas Flare (Allowable SSM Emissions)	68.5	10.3	5,176.6	776.5[1]
F-02	Inlet and Residue Flare (Allowable Emissions)	0.03	0.12	0.06	0.2
F-02	Inlet and Residue Flare (Allowable SSM Emissions)	563.5	9.1	4,064.0	63.4

Targa does not have process streams that vent to flare during normal operations. Targa's authorized flaring is associated with startup, shutdown, and maintenance (SSM) events. As required under 20.2.7.14, Targa developed and implemented a plan to minimize emissions during routine and predictable startup, shutdown, and scheduled maintenance through work practice standards and good air pollution control practices. Targa has followed these requirements while continuing to look for ways to reduce and minimize emissions at the Eunice Gas Plant.

Targa minimizes emissions during startups, shutdowns, and maintenance activities through the use of industry standards and/or manufacturer recommended operating practices. In addition, equipment at the facility is equipped with safety devices that will aid in minimizing excess emissions during non-routine operating conditions. The following summarizes Targa's operational plans for minimizing excess emissions.

After reviewing options for minimizing emissions associated with flaring at Targa's Eunice Gas Plant, Targa has not identified any new options to lower flared emission rates beyond what it is already doing. Below is a more detailed explanation of what Targa already does to minimize emissions at the gas plant.

[1] Permit amendment for redundant AGI compressor has not been submitted and will lower annual PTE for SSM emissions significantly from EPN F-01. See Section 1.1.2 of Eunice's Four-Factor Analysis Report submitted 10/31/2019.

1.1. MAINTENANCE

Targa takes a pro-active approach to facility and equipment maintenance. Operations personnel are aware of the importance of proper and efficient operation of equipment. Moreover, Targa recognizes the economic incentives to maintain and operate equipment efficiently. Malfunctioning equipment wastes resources and costs money.

Equipment at the facility is maintained in accordance with manufacturers' recommendations, industry best operating practices, and Targa's own practices designed to minimize downtime and non-routine operations. Procedures exist for maintenance of each major piece of equipment; personnel are trained in proper procedures; and Targa's own internal review processes ensure that procedures are followed. As a result, non-routine operational events and consequent excess emissions are minimized.

1.2. STARTUP AND SHUTDOWN

Targa's Eunice Gas Plant is shutdown annually, in conjunction with required third party pipeline maintenance outages. During this downtime, Targa conducts annual inspections and maintenance of its equipment to minimize downtime. However, due to the nature of oil and natural gas production, natural gas production rates cannot be easily turned on and off when a gas plant needs to be offline for maintenance activities. When natural gas cannot be processed, the gas must be vented or combusted.

During startup of the gas plant some flaring is necessary and cannot be avoided. The first processing step at the plant involves removal of carbon dioxide (CO_2) and hydrogen sulfide (H_2S) followed by the removal of water from the gas. This processing is necessary because Eunice utilizes a cryogenic process to split out methane from the heavier hydrocarbons found in raw natural gas. The cryogenic process operates at approximately -150°F. Due to this very cold temperature, the gas must meet very low specifications for water, CO2 and H2S content. Additionally, the natural gas, methane, produced from the cryogenic process must meet several specifications for BTU value as well as ethane content prior to the pipeline accepting the gas.

During startup, the gas will not initially meet the specifications required to go onto the next step in the process. Therefore, there is a period of time flaring of the gas prior to being able to introduce it into the next step of the process. Therefore, the gas must be flared initially until the stream reaches the specifications and can be routed to the next step in the process.

1.3. MINIMIZING EMISSIONS

To reduce emissions during equipment shutdowns for maintenance or operational outages, procedures are designed to minimize the duration of events. Such procedures include the following:

- Compression and other operational loads may be shifted to other units.
- Maintenance may be scheduled for periods of low load.
- Use of spare equipment to maintain operating rates during routine maintenance downtime of certain equipment, like natural gas fired engines.
- Multiple maintenance activities may be scheduled to occur simultaneously.
- Gas may be routed to other nearby gas plants.
- Producers may be asked to shut-in production to minimize gas flow to the plant.
- Startup is conducted with lower H_2S gas streams. Higher H_2S streams are not introduced to the gas plant inlet until the plant is operating normally.

- Compressors are first blown down to lower pressure process equipment prior to venting to reduce volume of process gas emitted (for example blowdown higher stage compressors to first stage suction at approximately 5 psig rather than venting from operating pressure that can be over 100 psig).
- Startup procedures for the turbines and engine are normally completed in less than five minutes, and shutdown procedures are normally completed in less than two minutes.

Targa believes the Eunice Gas Plant already utilizes efficient processes and mitigation strategies to reduce flaring emissions through the use of an acid gas injection system as well as by the techniques explained in this addendum. Targa is not aware of control technology that could further reduce emissions from the gas plant.

NMED Final Cost Evaluation
Targa Midstream Services - Monument Gas Plant

Facility Information

Targa Resources - Monument	**Facility**
Two 1950s 2SLB RICE, 800 HP	**Units**
C-01 and C-02	**Unit IDs**
LEC	**Evaluated Pollution Control**
3.0	**Post-control Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
800	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		C-01	C-02	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 1,800,000	$ 1,800,000	Targa 8/4/23 FFA update, 2023$	Equipment, materials and labor to install
Other Direct Capital Costs 1 ($)	ODC1	$ 143,977	$ 143,977	Targa 8/4/23 FFA update, 2023$ (removed the 30% increase from the 2019$ estimate and adjusted to 2023$ using CEPCI)	Cooling system, fuel system and custody transfer
Other Direct Capital Costs 2 ($)	ODC2	$ 383,509	$ 383,509	Targa 8/4/23 FFA update, 2023$	Permitting, taxes and contingency
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Not specified by Targa
Total Capital Costs - Direct ($)	TCC	$ 2,327,486	$ 2,327,486	-	PEC + ODC1 + ODC2 + IDC
Additional Capital ($)	AC	$ -	$ -	-	Targa included $6.3M for electrical substation upgrades needed to operate electric blowers associated with LEC. NMED omitted these costs for several reasons, most notably the fact that the vendor estimate provided by Targa specified turbochargers (which are powered by the engine's exhaust) instead of electric blowers.
Total Capital Investment ($)	TCI	$ 2,327,486	$ 2,327,486	-	TCC + AC
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	20	20	Targa 8/4/23 FFA update	Consistent with other FFAs
Capital Recovery Factor	CRF	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 228,308	$ 228,308	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	-	Incremental O&M of a LEC retrofit is expected to be negligible. Targa included $164K per engine in additional electricity costs for electric blowers. NMED omitted these costs for several reasons, most notably the fact that the vendor estimate provided by Targa specified turbochargers (which are powered by the engine's exhaust) instead of electric blowers.
Other Indirect Annual Costs ($/yr)	OAC	$ 93,099	$ 93,099	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 321,408	$ 321,408	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	81%	81%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	37.3	82.0	CY 2023 emissions testing and average operating hours (2019-2021).	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	37.3	82.0	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	30.4	66.8	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 10,568**	**$ 4,813**	-	TAC/ER
Price Index	PI	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 10,568**	**$ 4,813**	-	CE1 x PI

NMED Final Cost Evaluation
Targa Midstream Services - Monument Gas Plant

Facility Information

Targa Resources - Monument	**Facility**
Three 1950s 2SLB RICE, 600 HP	**Units**
C-04, C-05 and C-06	**Unit IDs**
LEC	**Evaluated Pollution Control**
3.0	**Post-control Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
600	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		C-04	C-05	C-06	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 1,800,000	$ 1,800,000	$ 1,800,000	Targa 8/4/23 FFA update, 2023$	Equipment, materials and labor to install
Other Direct Capital Costs 1 ($)	ODC1	$ 143,977	$ 143,977	$ 143,977	Targa 8/4/23 FFA update, 2023$ (removed the 30% increase from the 2019$ estimate and adjusted to 2023$ using CEPCI)	Cooling system, fuel system and custody transfer
Other Direct Capital Costs 2 ($)	ODC2	$ 383,509	$ 383,509	$ 383,509	Targa 8/4/23 FFA update, 2023$	Permitting, taxes and contingency
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	Not specified by Targa
Total Capital Costs - Direct ($)	TCC	$ 2,327,486	$ 2,327,486	$ 2,327,486	-	PEC + ODC1 + ODC2 + IDC
Additional Capital ($)	AC	$ -	$ -	$ -	-	Targa included $6.3M for electrical substation upgrades needed to operate electric blowers associated with LEC. NMED omitted these costs for several reasons, most notably the fact that the vendor estimate provided by Targa specified turbochargers (which are powered by the engine's exhaust) instead of electric blowers.
Total Capital Investment ($)	TCI	$ 2,327,486	$ 2,327,486	$ 2,327,486	-	TCC + AC
Interest Rate (%)	R	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	20	20	20	Targa 8/4/23 FFA update	Consistent with other FFAs
Capital Recovery Factor	CRF	0.0981	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 228,308	$ 228,308	$ 228,308	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	$ -	-	Incremental O&M of a LEC retrofit is expected to be negligible. Targa included $164K per engine in additional electricity costs for electric blowers. NMED omitted these costs for several reasons, most notably the fact that the vendor estimate provided by Targa specified turbochargers (which are powered by the engine's exhaust) instead of electric blowers.
Other Indirect Annual Costs ($/yr)	OAC	$ 93,099	$ 93,099	$ 93,099	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 321,408	$ 321,408	$ 321,408	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	83%	83%	59%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	19.5	98.3	33.1	CY 2023 emissions testing and average operating hours (2019-2021).	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	19.5	98.3	33.1	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	16.3	82.1	19.5	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 19,702**	**$ 3,915**	**$ 16,468**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 19,702**	**$ 3,915**	**$ 16,468**	-	CE1 x PI

NMED Final Cost Evaluation
Targa Midstream Services - Monument Gas Plant

Facility Information

Targa Resources - Monument	**Facility**
One 1960s 2SLB RICE, 880 HP	**Units**
C-24	**Unit IDs**
LEC	**Evaluated Pollution Control**
3.0	**Post-control Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
880	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		C-24	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 1,800,000	Targa 8/4/23 FFA update, 2023$	Equipment, materials and labor to install
Other Direct Capital Costs 1 ($)	ODC1	$ 143,977	Targa 8/4/23 FFA update, 2023$ (removed the 30% increase from the 2019$ estimate and adjusted to 2023$ using CEPCI)	Cooling system, fuel system and custody transfer
Other Direct Capital Costs 2 ($)	ODC2	$ 383,509	Targa 8/4/23 FFA update, 2023$	Permitting, taxes and contingency
Indirect Capital Costs ($)	IDC	$ -	-	Not specified by Targa
Total Capital Costs - Direct ($)	TCC	$ 2,327,486	-	PEC + ODC1 + ODC2 + IDC
Additional Capital ($)	AC	$ -	-	Targa included $6.3M for electrical substation upgrades needed to operate electric blowers associated with LEC. NMED omitted these costs for several reasons, most notably the fact that the vendor estimate provided by Targa specified turbochargers (which are powered by the engine's exhaust) instead of electric blowers.
Total Capital Investment ($)	TCI	$ 2,327,486	-	TCC + AC
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	20	Targa 8/4/23 FFA update	Consistent with other FFAs
Capital Recovery Factor	CRF	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 228,308	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	-	Incremental O&M of a LEC retrofit is expected to be negligible. Targa included $164K per engine in additional electricity costs for electric blowers. NMED omitted these costs for several reasons, most notably the fact that the vendor estimate provided by Targa specified turbochargers (which are powered by the engine's exhaust) instead of electric blowers.
Other Indirect Annual Costs ($/yr)	OAC	$ 93,099	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 321,408	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	85%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	171.1	CY 2023 emissions testing and average operating hours (2019-2021).	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	171.1	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	146.2	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 2,198**	-	TAC/ER
Price Index	PI	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 2,198**	-	CE1 x PI

NMED Final Cost Evaluation
Targa Midstream Services - Monument Gas Plant

Facility Information

Targa Resources - Monument	**Facility**
One 1970s 2SLB RICE,1100 HP	**Units**
C-28	**Unit IDs**
LEC	**Evaluated Pollution Control**
3.0	**Post-control Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
1100	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		C-28	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 1,400,000	Targa 8/4/23 FFA update, 2023$.	Equipment, materials and labor to install. Targa specified the egine is already turbocharged in its 8/4/23 update.
Other Direct Capital Costs 1 ($)	ODC1	$ 143,977	Targa 8/4/23 FFA update, 2023$ (removed the 30% increase from the 2019$ estimate and adjusted to 2023$ using CEPCI)	Cooling system, fuel system and custody transfer
Other Direct Capital Costs 2 ($)	ODC2	$ 383,509	Targa 8/4/23 FFA update, 2023$.	Permitting, taxes and contingency
Indirect Capital Costs ($)	IDC	$ -	-	Not specified by Targa
Total Capital Costs - Direct ($)	TCC	$ 1,927,486	-	PEC + ODC1 + ODC2 + IDC
Additional Capital ($)	AC	$ -	-	Targa included $6.3M for electrical substation upgrades needed to operate electric blowers associated with LEC. NMED omitted these costs for several reasons, most notably the fact that the vendor estimate provided by Targa specified turbochargers (which are powered by the engine's exhaust) instead of electric blowers.
Total Capital Investment ($)	TCI	$ 1,927,486	-	TCC + AC
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	20	Targa 8/4/23 FFA update	Consistent with other FFAs
Capital Recovery Factor	CRF	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 189,071	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	-	Incremental O&M of a LEC retrofit is expected to be negligible. Targa included $164K per engine in additional electricity costs for electric blowers. NMED omitted these costs for several reasons, most notably the fact that the vendor estimate provided by Targa specified turbochargers (which are powered by the engine's exhaust) instead of electric blowers.
Other Indirect Annual Costs ($/yr)	OAC	$ 77,099	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 266,171	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	58%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	32.5	CY 2023 emissions testing and average operating hours (2019-2021).	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	32.5	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	18.7	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 14,223**	-	TAC/ER
Price Index	PI	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 14,223**	-	CE1 x PI

NMED Final Cost Evaluation
Targa Midstream Services - Monument Gas Plant

Facility Information

Targa Resources - Monument	**Facility**
Two 1950s 2SLB RICE, 800 HP	**Units**
C-01 and C-02	**Unit IDs**
Replacement with new RICE	**Evaluated Pollution Control**
0.5	**Post-control Emissions Rate (g NOx/bhp-hr)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired spark ignited RICE >500 and <1875 bhp

Supporting Information

2020	**Calendar year associated with cost estimates**
800	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		C-01	C-02	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 2,581,600	$ 2,581,600	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $3227/hp cost metric as Targa did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered RICE.
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	30	30	ERG experience based on discussions with RICE manufacturers	
Capital Recovery Factor	CRF	0.0847	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 218,587	$ 218,587	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	-	Incremental O&M reasonably negligible
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 218,587	$ 218,587	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	97%	97%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	37.3	82.0	CY 2023 emissions testing and average operating hours (2019-2021).	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	37.3	82.0	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	36.2	79.4	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 6,042**	**$ 2,752**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 and thus assumed costs are in 2020$
Price Index	PI	1.34	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 8,096**	**$ 3,687**	-	CE1 x PI

NMED Final Cost Evaluation
Targa Midstream Services - Monument Gas Plant

Facility Information

Targa Resources - Monument	**Facility**
Three 1950s 2SLB RICE, 600 HP	**Units**
C-04, C-05 and C-06	**Unit IDs**
Replacement with new RICE	**Evaluated Pollution Control**
0.5	**Post-control Emissions Rate (g NOx/bhp-hr)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired spark ignited RICE >500 and <1875 bhp

Supporting Information

2020	**Calendar year associated with cost estimates**
600	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		C-04	C-05	C-06	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 1,936,200	$ 1,936,200	$ 1,936,200	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $3227/hp cost metric as Targa did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered RICE.
Interest Rate (%)	R	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	30	30	30	ERG experience based on discussions with RICE manufacturers	
Capital Recovery Factor	CRF	0.0847	0.0847	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 163,940	$ 163,940	$ 163,940	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	$ -	$ -	-	Incremental O&M reasonably negligible
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 163,940	$ 163,940	$ 163,940	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	97%	97%	93%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	19.5	98.3	33.1	CY 2023 emissions testing and average operating hours (2019-2021).	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	19.5	98.3	33.1	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	19.0	95.6	30.8	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 8,627**	**$ 1,714**	**$ 5,322**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 and thus assumed costs are in 2020$
Price Index	PI	1.34	1.34	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 11,560**	**$ 2,297**	**$ 7,132**	-	CE1 x PI

NMED Final Cost Evaluation
Targa Midstream Services - Monument Gas Plant

Facility Information

Targa Resources - Monument	**Facility**
One 1960s 2SLB RICE, 880 HP	**Units**
C-24	**Unit IDs**
Replacement with new RICE	**Evaluated Pollution Control**
0.5	**Post-control Emissions Rate (g NOx/bhp-hr)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired spark ignited RICE >500 and <1875 bhp

Supporting Information

2020	**Calendar year associated with cost estimates**
880	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		C-24	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 2,839,760	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $3227/hp cost metric as Targa did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered RICE.
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	30	ERG experience based on discussions with RICE manufacturers	
Capital Recovery Factor	CRF	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 240,446	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	-	Incremental O&M reasonably negligible
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 240,446	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	98%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	171.1	CY 2023 emissions testing and average operating hours (2019-2021).	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	171.1	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	167.0	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 1,440**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 and thus assumed costs are in 2020$
Price Index	PI	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 1,929**	-	CE1 x PI

NMED Final Cost Evaluation
Targa Midstream Services - Monument Gas Plant

Facility Information

Targa Resources - Monument	**Facility**
One 1970s 2SLB RICE,1100 HP	**Units**
C-28	**Unit IDs**
Replacement with new RICE	**Evaluated Pollution Control**
0.5	**Post-control Emissions Rate (g NOx/bhp-hr)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired spark ignited RICE >500 and <1875 bhp

Supporting Information

2020	**Calendar year associated with cost estimates**
1100	**Maximum Power Output (hp/unit)**

Economic Evaluation

Cost Component		C-28	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 3,549,700	9/8/20 info from El Paso Natural Gas	All-in estimate ($/HP) x Maximum Power Output (HP); Using EPNG's $3227/hp cost metric as Targa did not provide a cost evaluation for replacement with an equivalent fossil fuel-powered RICE.
Interest Rate (%)	R	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	30	ERG experience based on discussions with RICE manufacturers	
Capital Recovery Factor	CRF	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 300,557	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ -	-	Incremental O&M reasonably negligible
Other Indirect Annual Costs ($/yr)	OAC	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 300,557	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	93%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	32.5	CY 2023 emissions testing and average operating hours (2019-2021).	
Future Utilization Adjustment (%)	FUA	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	32.5	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	30.2	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 9,960**	-	TAC/ER; Cost info provided by EPNG on 9/8/20 and thus assumed costs are in 2020$
Price Index	PI	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 13,347**	-	CE1 x PI

NMED Final Cost Evaluation
Targa Midstream Services - Monument Gas Plant

Facility Information

Targa Resources - Monument	**Facility**
1960s 2SLB RICE	**Units**
Varies	**Unit IDs**
Replacement with EMD	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (g NOx/bhp-hr)**

Supporting Information

2023	**Calendar year associated with cost estimates**
Varies	**Maximum Power Output (hp/unit)**
6,283,299	**Cost of Electrical Substation Upgrades (2023$, Targa 8/4/23 FFA update)**
4	**Number of groups of units that will be replaced with EMD (for apportionment of substation costs)**

Economic Evaluation

Cost Component		C-01, C-02	C-04, C-05, C-06	C-24	C-28	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ 5,403,750	$ 5,403,750	$ 4,585,000	$ 9,170,000	Targa 8/4/23 FFA update, 2023$	Equipment, install labor and materials. Removed Targa's 30% increase and adjusted to 2023$ using CEPCI.
Other Direct Capital Costs ($)	ODC	$ 262,000	$ 262,000	$ 1,000,000	$ 700,000	Targa 8/4/23 FFA update, 2023$	Relocation/reconstruction of shop/storage. Removed Targa's 30% increase and adjusted to 2023$ using CEPCI (for C-01/C-02 and C-04/C-05/C-06).
Indirect Capital Costs ($)	IDC	$ 40,000	$ 40,000	$ 40,000	$ 40,000	Targa 8/4/23 FFA update, 2023$	Permitting
Total Capital Costs - Direct ($)	TCC	$ 5,705,750	$ 5,705,750	$ 5,625,000	$ 9,910,000	-	PEC + ODC + IDC
Additional Capital ($)	AC	$ 1,570,825	$ 1,570,825	$ 1,570,825	$ 1,570,825	Targa 8/4/23 FFA update	Substation upgrade cost spread across all affected RICE
Total Capital Investment ($)	TCI	$ 7,276,575	$ 7,276,575	$ 7,195,825	$ 11,480,825	-	TCC + AC
Interest Rate (%)	R	7.50%	7.50%	7.50%	7.50%	Bank prime rate as of December 2024	Targa did not provide a company-specific rate
Useful Life (yr)	Y	25	25	25	25	Consistent with other FFAs	
Capital Recovery Factor	CRF	0.0897	0.0897	0.0897	0.0897	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 652,786	$ 652,786	$ 645,542	$ 1,029,952	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 117,944	$ 187,188	$ 97,223	$ 55,149	-	AED + AOM + AFC
Additional Electricity Demand ($/yr)	AED	$ 229,408	$ 367,896	$ 187,966	$ 103,818	Engineering judgement	Assumes 60% load, 95% efficiency, and $0.053/kWh price (per Targa)
Additional Maintenance ($/yr)	AM	$ -	$ -	$ -	$ -	Engineering judgment	Assumed to be negligible
Associated non-electricity O&M ($/yr)	AOM	$ 3,240	$ 3,240	$ 3,240	$ 3,240	Targa 8/4/23 FFA update	Incremental maintenance at 54 hr/yr and $60/hr
Annual Fuel Credit ($/yr)	AFC	$ (114,704)	$ (183,948)	$ (93,983)	$ (51,909)	ERG calculation	Assumed equal to 50% of AED
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 770,731	$ 839,974	$ 742,765	$ 1,085,102	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	100%	100%	100%	100%	-	No emissions from EMD units
Baseline Actual NOx Emissions (ton/yr)	BAE	119.3	150.9	171.1	32.5	CY 2023 emissions testing and average operating hours (2019-2021).	
Future Utilization Adjustment (%)	FUA	0%	0%	0%	0%	-	Not requested by Targa
Projected Actual Emissions (ton/yr)	PAE	119.3	150.9	171.1	32.5	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	119.3	150.9	171.1	32.5	-	PAE x Eff
2023$ Cost Effectiveness ($/ton)	**CE1**	**$ 6,460**	**$ 5,565**	**$ 4,340**	**$ 33,421**	-	TAC/ER
Price Index	PI	1.00	1.00	1.00	1.00	-	2024 CEPCI* / 2023 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 6,460**	**$ 5,565**	**$ 4,340**	**$ 33,421**	-	CE1 x PI

REGIONAL HAZE FOUR-FACTOR ANALYSIS

Targa Midstream Services LLC – Monument Gas Plant

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1. EXECUTIVE SUMMARY

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR).[1] The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across the United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

> *(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A).*
>
> *(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B).*

Currently, we are in the second planning period for national regional haze efforts. There are a few key distinctions from the processes that took place during the first planning period. Most notably, the second planning period analysis will distinguish between "natural" and "anthropogenic" sources. Using a Photochemical Grid Model (PGM), the Western Regional Air Partnership (WRAP) in coordination with the EPA will compare anthropogenic source contributions against natural background concentrations.

Pursuant to 40 CFR 51.308(d)(3)(iv), "The State must identify all anthropogenic sources of visibility impairment considered by the State in developing its long-term strategy. The State should consider major and minor stationary sources, mobile sources, and area sources." To accomplish this for major stationary sources, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for Title V sources and screened each facility's potential impact on visibility in Class I areas using a "Q/d" analysis, where "Q" is the magnitude of emissions that could impact ambient visibility, and "d" is the distance of a facility to a Class I area. From this analysis, 24 facilities were identified by the NMED. On July 19, 2019 the NMED informed Targa Midstream Services LLC (Targa) that its Monument Gas Plant was identified as one of the sources potentially contributing to regional haze at the Carlsbad Caverns National Park Class I Area.

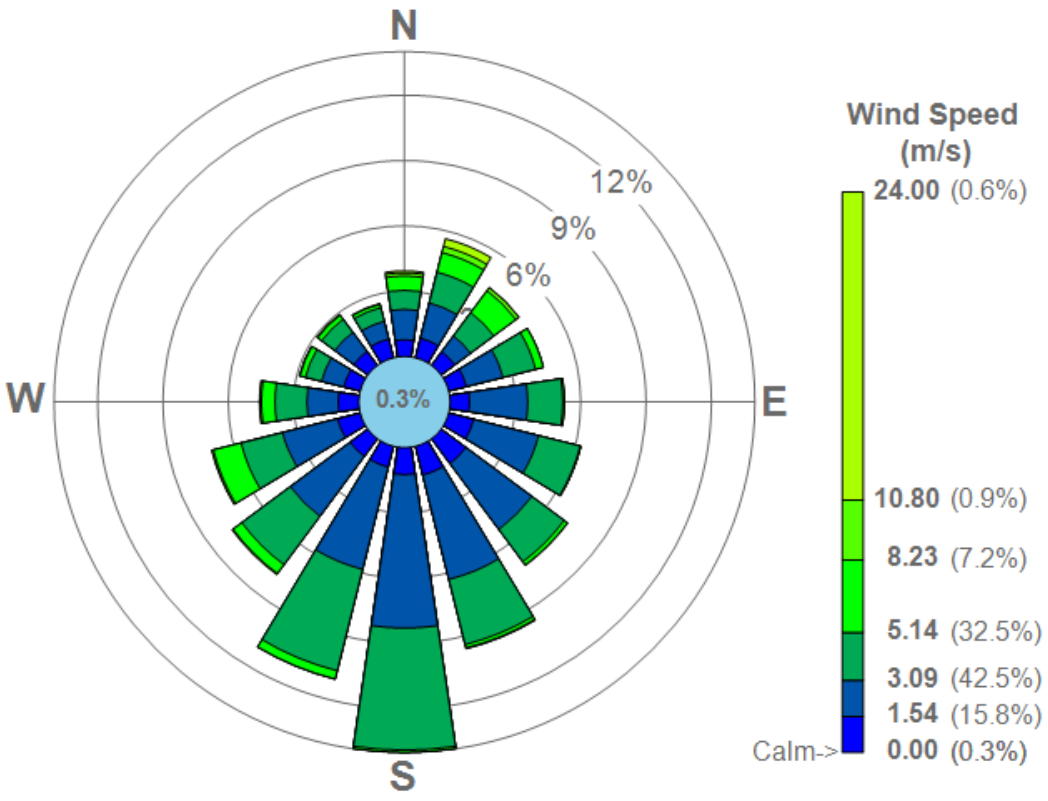
[1] Federal Register / Vol. 64, No. 126 /Thursday, July 1, 1999 (https://www.govinfo.gov/content/pkg/FR-1999-07-01/pdf/99-13941.pdf).

1.1. CONTRIBUTION TO VISIBILITY

1.1.1. Lack of Contribution to Visibility Impairment Due To Prevailing Winds

The NMED did not consider actual contribution to visibility impairment when selecting sources for the Four-Factor Analysis, but this is a critical factor in establishing realistic reasonable progress goals for Class I areas. In Figure 1-1 below, the prevailing wind from Hobbs, NM, can be used to estimate this facility's potential impact on the nearest Class I Area, Carlsbad Caverns National Park. Targa's Monument Gas Plant is located approximately 68.2 miles northeast at a wind vector of 65.9 degrees from the Carlsbad Caverns. The 2015 meteorological data from the NMED website at the Hobbs, NM meteorological station shows that wind blows from 56.3 to 78.8 degrees at a frequency of approximately 4.5%.[2] Based off this infrequent amount of time the wind blows from Targa's Monument Gas Plant toward Carlsbad Caverns, Targa believes that it is unlikely that the facility's potential emissions impact visibility at Carlsbad Caverns. Therefore, when balancing retrofit costs and visibility improvements, NMED should remain mindful that emissions from this facility are unlikely to contribute to regional haze at Carlsbad Caverns.

Figure 1-1. Hobbs, NM Meteorological Data, 2015 Wind rose



[2] https://www.env.nm.gov/air-quality/meteorological-data/

1.1.2. Lack of Contribution to Visibility Impairment Due to Already Effective SO_2 Controls

Further, with respect to SO_2 emissions, Targa controls H_2S emissions from the amine unit through operation of an acid gas injection (AGI) well and is in the process of adding redundant electric compression to the AGI well system to further reduce SO_2 emissions from the flare during SSM and malfunction events. The addition of the redundant electric compression is solely required by a Settlement Agreement and Stipulated Final Compliance Order between the Environmental Protection Division of the New Mexico Environment Department and Targa Midstream Services LLC. Targa expects this project to reduce flaring emissions at Monument Gas Plant by approximately 150-200 tons per year of SO_2. The installation of the redundant compression constitutes effective emission control technology to meet emission reductions required under the Settlement Agreement. This project will be complete by September 1, 2020; therefore, occurring during the 2nd Planning Period. There are no further SO_2 control options for the amine unit. Thus, the only equipment at this facility subject to this regional haze evaluation emit NOx.

Per 40 CFR 51.308(f)(2) of the Regional Haze rule, the NMED must determine emission reduction measures that are necessary to make reasonable further progress. The NMED, in an outreach webinar on Regional Haze Planning held on October 2, 2019, presented data on the most impaired days. This presentation identified ammonium sulfate as the largest contributor of visibility impairment in the National Parks of New Mexico. Ammonium sulfate is a byproduct of gaseous sulfur dioxide which becomes oxidized in the atmosphere to form sulfate particulate matter. This sulfate particulate matter is composed of sulfuric acid and corresponding salts such as ammonium sulfate. Since this information indicates the major contribution to regional haze is from sulfur dioxide emissions, not nitrogen dioxide emissions, the NMED should ensure that any required NOX reductions show significant contribution to improving visibility prior to requiring capital expenditures. Because emissions from Targa's Monument Gas Plant are not expected to impact visibility in the Carlsbad Caverns National Park Class I Area based on predominant wind direction (see Section 1.1), the NMED should find all technically feasible NO_X controls for the Monument Gas Plant economically unreasonable.

1.2. EQUIPMENT ANALYSIS

In coordination with guidance provided by WRAP, the NMED devised criteria to determine specific equipment that is subject to the four factor analysis. In the NMED's notification letter to Targa, they specify that any equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The equipment at the facility that is subject to this analysis, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant, are reported in Table 1.

Table 1. Summary of equipment and applicability of the four-factor analysis.

Unit	Equipment	NO_X (lb/hr)	NO_X (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 (lb/hr)	SO_2 (tpy)	SO_2 Subject to Analysis? (Yes/No)
C-01	Natural Gas Fired Two-Stroke Lean-Burn Engine	27.8	121.8	Yes	0.11	0.47	No
C-02	Natural Gas Fired Two-Stroke Lean-Burn Engine	27.8	121.8	Yes	0.11	0.47	No
C-04	Natural Gas Fired Two-Stroke Lean-Burn Engine	25.1	109.9	Yes	0.06	0.26	No
C-05	Natural Gas Fired Two-Stroke Lean-Burn Engine	25.1	109.9	Yes	0.06	0.26	No
C-06	Natural Gas Fired Two-Stroke Lean-Burn Engine	25.1	109.9	Yes	0.06	0.26	No
C-24	Natural Gas Fired Two-Stroke Lean-Burn Engine	41.9	183.5	Yes	0.17	0.76	No
C-28	Natural Gas Fired Two-Stroke Lean-Burn Engine	16.6	72.7	Yes	0.13	0.58	No
AM-01/ F-03	Amine Gas Treating Unit/Flare[a]	-	-	No	5817.5	872.6	Yes

[a] This unit is controlled by an acid gas injection well during normal operations and a flare during SSM or malfunction activities. Hydrogen sulfide emissions from this unit are combusted to form sulfur dioxide at flare F-03.

Once the applicability of process equipment and pollutants has been determined, potential retrofit control technologies must be identified in accordance with 40 CFR 51, Appendix Y. At the recommendation of the NMED,[3] this is primarily achieved by utilizing RACT/BACT/LAER Clearinghouse (RBLC) data. In order to determine the most relevant and current retrofit controls available, the RBLC was queried for the two-stroke lean-burn engines over the past 20 years. Summaries of the search results are provided and discussed in Section 2 of this report. The facility engineers then reviewed the list of available retrofit technologies and performed a technical feasibility assessment for each control option. The required four-factor analysis is then conducted for those controls that are technically feasible.

Targa conducted the required Four Factor Analysis for engines listed in Table 1 above. Based on a comprehensive review of the RBLC and engine control vendor's input of available control technologies for natural gas fired engines, Targa determined the only feasible additional control option is installation of clean burn technology for the 2SLB engines.

[3] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

2. BACKGROUND INFORMATION & TECHNICAL FEASIBILITY

2.1. SO_2 EMISSIONS

Targa controls H_2S emissions from the amine unit through operation of an acid gas injection (AGI) well at the site and is in the process of adding redundant electric compression to the AGI well system to further reduce SO_2 emissions during SSM and malfunction flaring events. The addition of the redundant electric compression is solely required by a Settlement Agreement and Stipulated Final Compliance Order between the Environmental Protection Division of the New Mexico Environment Department and Targa Midstream Services LLC. Targa expects this project to reduce SO_2 flaring emissions at the Monument Gas Plant by approximately 150-200 tons per year. The installation of the redundant compression constitutes effective emission control technology to meet emission reductions required under the Settlement Agreement. This project will be complete by September 1, 2020 and therefore occurs during the 2nd Planning Period.

There are no further control options for the amine unit. No further analysis should be necessary to evaluate SO_2 emissions from the amine treater since no additional control equipment can be added to reduce SO_2 emissions at the site. Therefore, Targa will not assess any further control technology for this process unit.

2.2. NO_X EMISSIONS

Monument Gas Plant has seven (7) natural gas-fired two-stroke lean-burn engines. Units C-01, C-02, C-04, C-05, C-06, C-24, and C-28 that are subject to review under this analysis. The only pollutant subject to evaluation for these units is nitrogen oxides (NO_X). More detailed information on each engine is listed in Table 2 below:

Table 2. Summary of equipment and applicability of the four-factor analysis.

Unit	Make & Model	Date of Manufacture	Permitted Capacity
C-01	Clark RA-8	1956	800 hp
C-02	Clark RA-8	1956	800 hp
C-04	Clark RA-6	1956	600 hp
C-05	Clark RA-6	1956	600 hp
C-06	Clark RA-6	1956	600 hp
C-24	Clark HRA-8	1969	880 hp
C-28	Cooper Bessemer GMVA-8	1977	1100 hp

2.2.1. Two-Stroke Lean-Burn Engines

Table 3. Potential Control Equipment for Two-Stroke Lean-Burn RICE

Control Equipment	Technically Feasible?	NO_X Control Efficiency
Good Combustion Practices and Fuel Selection	**Yes**	**Base Case**
Clean Burn Technology	**Yes**	**70% to 90%**
Selective Catalytic Reduction	**No**	**N/A**
Non-Selective Catalytic Reduction	**No**	**N/A**

2.2.1.1. Two-Stroke Lean-Burn Engines Background

A reciprocating internal combustion engine (RICE) is a device that uses the combustion of fuel and air in an internal chamber to generate a reciprocating motion and convert heat energy into mechanical work. The units use a piston to draw air and fuel into the combustion chamber and compress it. The compressed air/fuel mixture is then ignited, generating combustion in the chamber. The energy of combustion pushes out the piston, turning a crankshaft and producing mechanical work. In the same cycle, the products of combustion remaining in the chamber are released and exhausted from the unit.

Natural gas-fired RICE are separated into multiple design classes, including 2-stroke lean-burn (2SLB), 4-stroke lean-burn (4SLB), and 4-stroke rich-burn (4SRB). The four-stroke design uses four strokes of the piston, or two turns of the crankshaft, to complete the power cycle. The two-stroke design completes the power cycle in a single revolution of the crankshaft. Rich-burn engines are designed to operate close to the stoichiometric, or chemically balanced, air-to-fuel ratio (around 16:1) with exhaust oxygen levels less than 4%, while lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1), with exhaust oxygen levels of 12% or more.[4] .

NO_X is formed in reciprocating engines by the following mechanisms:

(1) Thermal NO_X - the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion,
(2) Fuel NO_X - the evolution and reaction of fuel-bound nitrogen compounds with oxygen, and
(3) Prompt NO_X - the early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The Monument engines also use natural gas fuel; therefore, the formation of prompt NO_X and fuel NO_X will again be insignificant, and this analysis will focus on thermal NO_X. The rate of NO_X formation through the thermal NO_X mechanism is highly dependent upon the air-to-fuel ratio, combustion temperature, and residence time at the combustion temperature. Maximum thermal NO_X formation occurs near the stoichiometric air-to-fuel mixture ratio because combustion temperatures are greatest at this ratio[5].

NO_X reduction in natural gas-fired RICE can be accomplished by three general methods, as follows:[6]

(1) Operational control methods, such as adjusting the timing or other operating parameters.

[4] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
[5] Ibid.
[6] Ibid.

(2) Combustion control techniques, for example reducing the peak flame temperature or introducing inerts that limit initial NO_X formation.
(3) Post-combustion NO_X control technologies, which employ various strategies to chemically reduce NO_X.

The potential to emit (PTE) from each engine is reported in the Monument Gas Plant's NSR (0110M9R3) and Title V (P110-R2M1) permits as well as summarized in Table 1. Additionally, the NO_X emission rates from the RICE are calculated using stack test data.

2.2.1.2. Potential NO_X Controls for 2SLB Engines

Retrofit control options identified for 2SLB RICE were identified via comprehensive review of the RBLC and available technical literature and are summarized in Table 3. A detailed description and discussion of the technical feasibility and anticipated performance of each control is provided below.

2.2.1.2.1 Good Combustion Practices and Fuel Selection

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from large natural gas-fired lean-burn stationary internal combustion engines; therefore, it has been determined that this method of NO_X control is feasible for the 2SLB engines at Monument Gas Plant. However, these practices are currently in use at Monument Gas Plant. No further assessment of these control practices has been included in this report.

Monument Gas Plant conducts routine maintenance on all engines at the site per manufacture recommendations using trained maintenance personnel and using pipeline quality natural gas.

2.2.1.2.2 Clean Burn Technology

Clean Burn Technology (CBT) is another term for utilizing combustion mixtures in engines with fuel-lean air-to-fuel ratios. This method of reducing NO_X emissions involves reconfiguring the engines by adding an air-to-fuel ratio controller so that they are capable of operating at more desirable ratios.

As described in Section 2.1.1 of this report, lean-burn engines operate at air-to-fuel ratios ranging from 20:1 to 50:1. A combustion mixture with a higher air-to-fuel ratio results in reduced NO_X emissions, because using fuel-lean mixtures lowers the combustion temperature by diluting energy input. 2SLB engines are typically designed to operate at the high air-to-fuel ratios employed in CBT; however, further increasing the air-to-fuel ratio in lean-burn engines can decrease the NO_X emissions.[7]

[7] State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines, State of New Jersey Department of Environmental Protection, 2003.

In order to avoid derating the engine, combustion air must be increased at constant fuel flow. To achieve this, the engine would need to be retrofitted with a turbocharger, which forces additional air into the combustion chamber, as well as an automatic air-to-fuel ratio controller.

Many 2SLB engines, such as naturally aspirated engines, do not have identical air-to-fuel ratios in each cylinder, which can result in limited ability to vary the air-to-fuel ratio. To maintain acceptable engine performance at lean conditions, high energy ignition systems (HEIS) have been developed that promote flame stability at very lean conditions.[8]

2SLB engines are mechanically capable of being retrofit with more sensitive air-to-fuel ratio controllers and running on higher air-to-fuel ratio combustion to control NO_X emissions. Therefore, it has been determined that this method of NO_X control is feasible for the 2SLB engines at Monument. On 2SLB RICE, air-to-fuel ratio adjustment generally achieves a 5 to 30% reduction in NO_X emissions; however, this reduction is very specific to each engine and typical loading.[9]

Targa was able to request potential NO_X reduction options from their engine control vendor including Clean Burn technology. The Clean Burn technology will reduce NO_X emissions between 70% and 90%. The units could be modified to operate with pre-combustion chambers and pilot fuel systems with Jet Cells which are needed to significantly lean the combustion mixture with the required capacity air source. The 2SLB engines will also need turbochargers or externally driven blowers added as well. If a 2SLB engine does need an externally driven blower, this will be an electric blower and require electricity to operate. At this time, Monument Gas Plant would have to significantly upgrade the power substation at the plant to operate blowers associated with these controls. The cost provided in Section 3 of this report does not include the cost to upgrade the electrical substation at the facility. An engineering design assessment would need to be completed before a total cost for the upgrade can be provided but is estimated at $1 million to $3 million.

Even with the power concerns, Targa has determined that this method of NO_X control is feasible for the 2SLB engines at the facility.

2.2.1.2.3 Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[10] The chemical reactions for this process are shown in the equations below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

An SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and an electronic control system. The electronic controls regulate the quantity of reagent injected as a function of engine load, speed, and temperature, so NO_X emissions reductions can be achieved. The

[8] Ibid.
[9] Ibid.
[10] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

catalyst effectiveness can reduce over time and ultimately become inactive. This inactivity can be caused by the following: [11]

- Poisoning of the active sites by flue gas constituents;
- Thermal sintering of active sites due to high temperatures within the catalyst reactor;
- Blinding/plugging/fouling of active sites by ammonia-sulfur salts and particulate matter; and
- Erosion due to high gas velocities.

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as ammonia slip. Unreacted ammonia in the exhaust can form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams can blind the catalyst and may necessitate the application of a soot blower.[12]

For an SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 and 850 °F), the material of the catalyst will affect the specific temperature range the exhaust must operate within. Exhaust gas temperatures greater than the upper limit will cause the NO_X and ammonia to pass through the catalyst unreacted.[13]

In order for the chemical reactions necessary for SCR to occur effectively, the exhaust streams injected with the reagent must be fairly oxygen rich. The exhaust oxygen levels for 2SLB engines are sufficient to support these reactions; therefore, this technology can be used on lean-burn engines. That said, the RBLC does not identify SCR as a control for these specific engine models.[14] This is likely because there is limited operating experience to date with the use of SCR on 2SLB RICE. Additionally, there is a historical precedent that installation of SCR on 2SLB engines can result in significant technical complications, including a necessity to derate the engines and unreliable operation post-retrofit.

The engine control vendors did not offer or suggest SCR as a suitable control option as there are significant challenges to install this equipment on the 2SLB units at Monument. The main challenge is most 2SLB engines have a poor air-to-fuel ratio that will not support the SCR control. The vendors provided CBT technology as the technically feasible option to control NO_X emissions from 2SLB engines. As SCR control technology is not listed in the RBLC tables for 2SLB engines, has not been a proven as an effective control of NO_X emissions for 2SLB engines and has significant operating challenges for 2SLB engines, Targa has determined this control is technically infeasible.

2.2.1.2.4 Non-Selective Catalytic Reduction

Non-Selective Catalytic Reduction (NSCR) is a control technique that uses residual hydrocarbons and carbon monoxide (CO) in engine exhaust as a reducing agent for NO_X. In an NSCR system, hydrocarbons and CO are oxidized by oxygen (O_2) and NO_X. The excess hydrocarbons, CO, and NO_X pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H_2O and CO_2, while reducing NO_X to N_2.[15] This technique does not require additional reagents to be injected because the

[11] Ibid.
[12] Ibid.
[13] U.S. EPA, AP-42, Section 3.2, "Natural Gas-fired Reciprocating Engines"
[14] Ibid.
[15] Ibid.

unburned hydrocarbons in the engine exhaust are used as the reductant. The chemical reactions for this process are shown in the equations below.[16]

Phase 1:
$$2CO + O_2 \rightarrow 2CO_2$$
$$2H_2 + O_2 \rightarrow 2H_2O$$
$$HC + O_2 \rightarrow CO_2 + H_2O$$

Phase 2:
$$NO_X + CO \rightarrow CO_2 + N_2$$
$$NO_X + H_2 \rightarrow H_2O + N_2$$
$$NO_X + HC \rightarrow CO_2 + H_2O + N_2$$

The reactions in Phase 1 of the chemical process above function to remove excess oxygen from the exhaust stream. This step is necessary because if the oxygen is not removed, it will react more readily with the CO and hydrocarbons than the NO_X, thus reducing the NO_X removal.

Despite this oxygen removal step in the chemical process, the engine exhaust gas stream must already have low levels of excess oxygen, or the oxygen will not be fully removed in Phase 1 and the NO_X removal will not be efficient. Consequently, application of the NSCR control technique is effectively limited to engines with normal exhaust oxygen levels of 4% or less. This includes naturally aspirated 4SRB engines and some turbocharged 4SRB engines. In order to achieve effective NO_X reduction performance, the engine may need to be run with a richer fuel adjustment than normal, resulting in an exhaust excess oxygen level closer to 1%.[17]

The exhaust oxygen levels for 2SLB engines are not sufficiently low to support the reactions described above; therefore, this technology is not a method used to control NO_X emissions from lean-burn engines. Furthermore, NSCR was not identified in the review of the RBLC as a potential control of NO_X emissions from large natural gas-fired lean-burn stationary RICE and AP-42 Section 3.2 does not list NSCR as an available control technique for 2SLB engines.[18] For these reasons, it has been determined that this method of NO_X control is infeasible for the 2SLB engines at Monument.

[16] U.S. EPA, "Compliance Assurance Monitoring Technical Guidance Document", Appendix B Review Draft, 2005
[17] U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"
[18] Ibid.

According to the EPA Control Cost Manual, there are five steps associated with evaluating the control cost effectiveness:

1. Obtain the facility parameters and regulatory options for a given facility;
2. Draft the control system design;
3. Size the control system components;
4. Estimate the costs of these individual components; and
5. Estimate the capital and annual costs of the entire system.

The cost effectiveness discussion and summary tables for the engines applicable to this analysis are provided in this section. Detailed cost control estimates are provided in Appendix B.

3.1. TWO-STROKE LEAN-BURN ENGINE CONTROLS

Table 4. Cost analysis summary of technically feasible controls for two-stroke lean-burn engines.

Control Equipment	Unit	Capital Cost ($)	Total Annual Cost ($)[a, b]	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Clean Burn Technology	C-01	**900,000[c]**	**175,311**	**20.58**	**8,519.78**
	C-02	**900,000[c]**	**175,311**	**27.99**	**6,263.84**
	C-04	**900,000[c]**	**175,311**	**5.17**	**33,892.19**
	C-05	**900,000[c]**	**175,311**	**16.67**	**10,517.35**
	C-06	**900,000[c]**	**175,311**	**12.65**	**13,857.01**
	C-24	**900,000[c]**	**175,311**	**103.87**	**1,687.77**
	C-28	**850,000[c]**	**171,127**	**2.99**	**57,280.51**

[a]Total Annual Cost includes the annualized capital cost, as well as the direct and indirect annual operating costs.
[b] This cost does not include annual operating costs for upgrade to the electrical substation that would incur. A full engineering assessment would need to be completed in order to know the full annual cost of this upgrade.
[c] The Capital Cost does not include the $1 million to $3 million required to upgrade the electrical substation at the site needed to power blowers for the CTB technology. A full engineering assessment would need to be completed in order to know the full cost of this upgrade.

3.1.1. Good Combustion Practices and Fuel Selection

Targa already employs good combustion practices and fuel selection. There is no further cost to assess for this control technology.

3.1.2. Clean Burn Technology

Targa has received an estimated direct capital costs for the equipment and vendor labor associated with implementing a CBT on the 2SLB models located at Monument from the engine control vendor. Based on prior knowledge of the equipment, Targa estimated the direct annual costs (maintenance, operating labor, reagent cost, electricity cost, and catalyst cost) and indirect annual costs associated with Targa's internal labor, overhead and capital recovery for the project. Please note that the cost in Table 4 does not include the significant upgrade to the power substation at the plant to operate the blowers associated with these CTB controls as discussed in Section 2.2.12.2. The upgrade to the substation would require a Capital Cost of at least $1 million to $3 million. A full engineering design assessment would need to be completed before a final full cost can be provided.

This cost estimate assumes that the CBT will reduce NO_X emissions to an outlet concentration of 2 g/hp-hr, based on information provided by the engine control vender. The cost effectiveness for each engine control option are summarized in Table 4. The full cost estimation for each unit is included in Appendix B of this report. To calculate the emission reductions, Targa used the 2016 Emission Inventory (EI) data. This was compared to the maximum PTE emission rate of the equipment post-control to get an Emission Reduction (tpy) value. The Total Annual Cost was then divided by the Emission Reduction to come up with a Cost Effectiveness ($/ton) amount.

4.1. TWO-STROKE LEAN-BURN ENGINE CONTROLS

4.1.1. Good Combustion Practices and Fuel Selection

Targa already employs good combustion practices and fuel selection. There is no further time for compliance to assess for this control technology.

4.1.2. Clean Burn Technology

Targa estimates that approximately 7 years will be needed to budget, design, procure, permit and install the CBT equipment from the time the facility is required to add this control.

5.1. TWO-STROKE LEAN-BURN ENGINES

5.1.1. Good Combustion Practices and Fuel Selection

There are no anticipated unique or site-specific energy or non-air impacts imposed by continuing to use good combustion practices and fuel selection.

5.1.2. Clean Burn Technology

Clean burn technology control employs a combustion mixture with a higher air-to-fuel ratio, because using fuel-lean mixtures lowers the combustion temperature by diluting energy input. This will reduce NO_X emissions; however, a reduction in combustion temperature increases emissions of CO, due to incomplete combustion. The blowers associated with this control will require electrical power to operate. This additional power will cause additional strain on the electrical grid and require an upgrade to the electrical substation at the site.

6.1. TWO-STROKE LEAN-BURN ENGINE CONTROLS

6.1.1. Good Combustion Practices and Fuel Selection

Targa already employs good combustion practices and fuel selection. No further information needs to be assessed in this section.

6.1.2. Clean Burn Technology

The estimated useful life of the CTB equipment is 20 years, based on industry standards for life of the controls.

7. RESULTS & CONCLUSION

Based on a comprehensive review of the RBLC, and engine control vendor's input of available control technologies for the natural-gas fired engines located at Monument Gas Plant, Targa has determined that CBT and good combustion practices for the 2SLB engines are the only technically feasible NO_X control options for the engines being reviewed under this analysis. However, retrofitting these technologies would require Targa to spend significant amounts of time (for design and installation) and capital. In addition, based on the predominant wind direction and that SO_2, not NO_X, is the contaminant of interest for visibility impairment in Carlsbad Caverns, NO_X emissions from these pieces of equipment are inconsequential for regional haze purposes. Thus, retrofitting the Monument Gas Plant engines would be uneconomical and unnecessary for improving visibility.

APPENDIX A: RBLC TABLES

Attached is the RBLC tables, Table A-1 for the 2SLB Cooper Bessemer engines and Table A-2 for the 2SLB Clark engines.

Table A-1. 2SLB Cooper Bessemer Engines RBLC Tables.

RBLCID	FACILITY_NAME	PROCESS_NAME	THROUGHPUT	POLLUTANT	CONTROL_METHOD_DESCRIPTION
NE-0015	KN ENERGY. INC	IC ENGINE, 2511E, COOPER GMVA-6	750 HP	Nitrogen Oxides (NOx)	
NE-0015	KN ENERGY. INC	IC ENGINE, 2512E, CLIMAX V-125	320 HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, 2514E, INGERSOLL RAND SVG-12	660 HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, 2515E, WAUKESHA L3711	285 HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, 2516E, WAUKESHA L3711	285 HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	TURBINE, 2551E, SOLAR SATURN	1100 HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS.
NE-0015	KN ENERGY. INC	2-CYCLE LEAN BURN ENGINE, UNIT 2505E	1000 HP	Nitrogen Oxides (NOx)	2ND GENERATION CLEAN BURN CONTROL.
NE-0015	KN ENERGY. INC	IC ENGINE, 2506E	2200 HP	Nitrogen Oxides (NOx)	2ND GENERATION CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	TURBINE, 2507E, SOLAR T-1001	1100 HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	TURBINE, 2508E, SOLAR CENTAR	4756 HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS.
NE-0015	KN ENERGY. INC	IC ENGINE, 2503E, COOPER GMVA-10	1265 HP	Nitrogen Oxides (NOx)	CLEAN BURNCONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, 2504E, COOPER GMVA-6	750 HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, CLEAN BURN, 2517E COOPER GMVH-8	2000 HP	Nitrogen Oxides (NOx)	2ND GENERATION CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, (2), 2501E & 2502E CLARK RA-6	565 HP	Nitrogen Oxides (NOx)	2ND GENERATION CLEAN BURN CONTROLS
OK-0049	RELIANT, CHANDLER STA	COOPER BESSEMER GMWC-12 RECIP. COMBUSTION ENGINE	4000 HP	Nitrogen Oxides (NOx)	CLEAN BURN TECHNOLOGY
TX-0364	SALT CREEK GAS PLANT	(2) INGERSOLL-RAND ENGINES, #IR-SVG-8, EPN4&5	440 HP	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	HOT OIL HEATER, EPN6	12 MMBTU/H	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	(2) INGERSOLL-RAND ENGINES, #IR-SVG-8, EPN10A&B	1330 HP	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	GLYCOL REBOILER, EPN11	2.5 MMBTU/H	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	(3) COOPER-BESSEMER ENGINES, #GMVH-12C2, EPN21-23	3105 HP	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	HOT OIL HEATER, EPN26	32.5 MMBTU/H	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	(2) FLARES, EPN 9 & 29		Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	HP TEG FIREBOX, EPN30	3 MMBTU/H	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	COOPER-BESSEMER ENGINE, #GMVH-12, EPN1	2400 HP	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	(2) CLARK ENGINE, #TLAB-6, EPN2&3	2000 HP EACH	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0465	SALT CREEK GAS PLANT	COOPER-BESSEMER ENGINE 3105 HP	3105 HP	Nitrogen Oxides (NOx)	LEAN COMBUSTION
TX-0465	SALT CREEK GAS PLANT	HOT OIL HEATER	32.5 MMBTU/H	Nitrogen Oxides (NOx)	
TX-0465	SALT CREEK GAS PLANT	FLARES (2)		Nitrogen Oxides (NOx)	
TX-0465	SALT CREEK GAS PLANT	HP TEG FIREBOX		Nitrogen Oxides (NOx)	
TX-0465	SALT CREEK GAS PLANT	COOPER-BESSEMER ENGINE	2400 HP	Nitrogen Oxides (NOx)	LEAN COMBUSTION
TX-0465	SALT CREEK GAS PLANT	CLARK ENGINE (2)	2000 HP	Nitrogen Oxides (NOx)	LEAN COMBUSTION
TX-0465	SALT CREEK GAS PLANT	INGERSOLL-RAND ENGINE	440 HP	Nitrogen Oxides (NOx)	LEAN COMBUSTION
TX-0465	SALT CREEK GAS PLANT	HOT OIL HEATER	12 MMBTU/H	Nitrogen Oxides (NOx)	LEAN COMBUSTION
TX-0465	SALT CREEK GAS PLANT	INGERSOLL-RAND ENGINE 1330 HP	1330 HP	Nitrogen Oxides (NOx)	LEAN COMBUSTION
TX-0465	SALT CREEK GAS PLANT	GLYCOL REBOILER	2.5 MMBUT/H	Nitrogen Oxides (NOx)	

Table A-2. 2SLB Clark Engines RBLC Tables.

RBLCID	FACILITY_NAME	PROCESS_NAME	THROUGH	THROUGH	POLLUTANT	CONTROL_METHOD_DESCRIPTION
NE-0015	KN ENERGY. INC	IC ENGINE, 2511E, COOPER GMVA-6	750	HP	Nitrogen Oxides (NOx)	
NE-0015	KN ENERGY. INC	IC ENGINE, 2512E, CLIMAX V-125	320	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, 2514E, INGERSOLL RAND SVG-12	660	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, 2515E, WAUKESHA L3711	285	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, 2516E, WAUKESHA L3711	285	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	TURBINE, 2551E, SOLAR SATURN	1100	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS.
NE-0015	KN ENERGY. INC	2-CYCLE LEAN BURN ENGINE, UNIT 2505E	1000	HP	Nitrogen Oxides (NOx)	2ND GENERATION CLEAN BURN CONTROL.
NE-0015	KN ENERGY. INC	IC ENGINE, 2506E	2200	HP	Nitrogen Oxides (NOx)	2ND GENERATION CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	TURBINE, 2507E, SOLAR T-1001	1100	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	TURBINE, 2508E, SOLAR CENTAR	4756	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS.
NE-0015	KN ENERGY. INC	IC ENGINE, 2503E, COOPER GMVA-10	1265	HP	Nitrogen Oxides (NOx)	CLEAN BURNCONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, 2504E, COOPER GMVA-6	750	HP	Nitrogen Oxides (NOx)	CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, CLEAN BURN, 2517E COOPER GMVH-8	2000	HP	Nitrogen Oxides (NOx)	2ND GENERATION CLEAN BURN CONTROLS
NE-0015	KN ENERGY. INC	IC ENGINE, (2), 2501E & 2502E CLARK RA-6	565	HP	Nitrogen Oxides (NOx)	2ND GENERATION CLEAN BURN CONTROLS
TX-0364	SALT CREEK GAS PLANT	(2) INGERSOLL-RAND ENGINES, #IR-SVG-8, EPN4&5	440	HP	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	HOT OIL HEATER, EPN6	12	MMBTU/H	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	(2) INGERSOLL-RAND ENGINES, #IR-SVG-8, EPN10A&B	1330	HP	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	GLYCOL REBOILER, EPN11	2.5	MMBTU/H	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	(3) COOPER-BESSEMER ENGINES, #GMVH-12C2, EPN21-23	3105	HP	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	HOT OIL HEATER, EPN26	32.5	MMBTU/H	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	(2) FLARES, EPN 9 & 29			Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	HP TEG FIREBOX, EPN30	3	MMBTU/H	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	COOPER-BESSEMER ENGINE, #GMVH-12, EPN1	2400	HP	Nitrogen Oxides (NOx)	NONE INDICATED
TX-0364	SALT CREEK GAS PLANT	(2) CLARK ENGINE, #TLAB-6, EPN2&3	2000	HP EACH	Nitrogen Oxides (NOx)	NONE INDICATED

APPENDIX B: COST ANALYSIS SUPPORTING INFORMATION

The cost analysis was based on information received from engine control vendors or knowledge on the particular equipment and is provided in Table B-1 below.

Table B-1. Engine Cost Information.

Equipment	Model	Control Type	Purchased Equipment Cost [a] ($)	Direct & Indirect Installation Cost [b] ($)	Capital Cost ($)
Clark	RA-8	CBT	800,000	100,000	900,000
Clark	RA-6	CBT	800,000	100,000	900,000
Clark	HRA-8	CBT	800,000	100,000	900,000
Cooper Bessemer	GMVA-8	CBT	750,000	100,000	850,000

[a] The cost in this column is based on a control vendor estimated quote. This cost does not include the $1 million to $3 million required to upgrade the electrical substation at the site needed to power blowers for the CTB technology. A full engineering assessment would need to be completed in order to know the full cost of this upgrade.

[b] The cost in this column is based on Targa's knowledge of the equipment but does not include the additional costs of operating the upgraded electrical substation.

Monument Gas Plant

2SLB Engine - Clark RA-8	Interest Rate:	5.50%	
Units: C-01	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	800	hp	<-- As permitted
2016 Operating Hours	2357	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	11.9	g/hp-hr	<-- From 4/21/15 performance test
NO_X lb/hr:	20.99	lb/hr	<-- Calculated
NO_X tpy:	24.73	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		83.2%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:		3.53	lb/hr	
NO_X tpy:		4.16	tpy	
Total Cap Investment	$	900,000		<--Manufacturer specification
Annualized TCI:	$	75,311		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	175,311		
Emissions Reduction:		20.58	tpy	
Cost Effectiveness:	**$**	**8,519.78**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark RA-8	Interest Rate:	5.50%	
Units: C-02	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	800	hp	<-- As permitted
2016 Operating Hours	4069	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	9.8	g/hp-hr	<-- From 4/21/15 performance test
NO_X lb/hr:	17.28	lb/hr	<-- Calculated
NO_X tpy:	35.16	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		79.6%	Control Eff.	<-- Calculated ($NO_{X(in)}$ - $NO_{X(out)}$)/$NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		3.53	lb/hr	
NO_X tpy:		7.18	tpy	
Total Cap Investment	$	900,000		<--Manufacturer specification
Annualized TCI:	$	75,311		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	175,311		
Emissions Reduction:		27.99	tpy	
Cost Effectiveness:	**$**	**6,263.84**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark RA-6	Interest Rate:	5.50%	
Units: C-04	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	600	hp	<-- As permitted
2016 Operating Hours	990	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	9.9	g/hp-hr	<-- From 4/23/15 performance test
NO_X lb/hr:	13.10	lb/hr	<-- Calculated
NO_X tpy:	6.48	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		79.8%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		2.65	lb/hr	
NO_X tpy:		1.31	tpy	
Total Cap Investment	$	900,000		<--Manufacturer specification
Annualized TCI:	$	75,311		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	175,311		
Emissions Reduction:		5.17	tpy	
Cost Effectiveness:	**$**	**33,892.19**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark RA-6	Interest Rate:	5.50%	
Units: C-05	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	600	hp	<-- As permitted
2016 Operating Hours	3938	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	8.4	g/hp-hr	<-- From 4/22/15 performance test
NO_X lb/hr:	11.11	lb/hr	<-- Calculated
NO_X tpy:	21.88	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		76.2%	Control Eff.	<-- Calculated ($NO_{X(in)}$ - $NO_{X(out)}$)/$NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		2.65	lb/hr	
NO_X tpy:		5.21	tpy	
Total Cap Investment	$	900,000		<--Manufacturer specification
Annualized TCI:	$	75,311		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	175,311		
Emissions Reduction:		16.67	tpy	
Cost Effectiveness:	**$**	**10,517.35**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark RA-6	Interest Rate:	5.50%	
Units: C-06	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	600	hp	<-- As permitted
2016 Operating Hours	2035	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	11.4	g/hp-hr	<-- From 4/21/15 performance test
NO_X lb/hr:	15.08	lb/hr	<-- Calculated
NO_X tpy:	15.34	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		82.5%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		2.65	lb/hr	
NO_X tpy:		2.69	tpy	
Total Cap Investment	$	900,000		<--Manufacturer specification
Annualized TCI:	$	75,311		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	175,311		
Emissions Reduction:		12.65	tpy	
Cost Effectiveness:	**$**	**13,857.01**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark HRA-8	Interest Rate:	5.50%	
Units: C-24	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	880	hp	<-- As permitted
2016 Operating Hours	6610	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	18.2	g/hp-hr	<-- From 4/22/15 performance test
NO_X lb/hr:	35.31	lb/hr	<-- Calculated
NO_X tpy:	116.70	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		89.0%	Control Eff.	<-- Calculated ($NO_{X(in)}$ - $NO_{X(out)}$)/$NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		3.88	lb/hr	
NO_X tpy:		12.82	tpy	
Total Cap Investment	$	900,000		<--Manufacturer specification
Annualized TCI:	$	75,311		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	175,311		
Emissions Reduction:		103.87	tpy	
Cost Effectiveness:	**$**	**1,687.77**	**$/ton**	

Monument Gas Plant

2SLB Engine - Cooper Bessemer GMVA-8	Interest Rate:	5.50%	
Units: C-28	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1100	hp	<-- As permitted
2016 Operating Hours	573	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	6.3	g/hp-hr	<-- From 4/23/15 performance test
NO_X lb/hr:	15.28	lb/hr	<-- Calculated
NO_X tpy:	4.38	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		68.3%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		4.85	lb/hr	
NO_X tpy:		1.39	tpy	
Total Cap Investment	$	850,000		<--Manufacturer specification
Annualized TCI:	$	71,127		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	171,127		
Emissions Reduction:		2.99	tpy	
Cost Effectiveness:	**$**	**57,280.51**	**$/ton**	

REGIONAL HAZE FOUR-FACTOR ANALYSIS
SSM FLARING ADDENDUM

Targa Midstream Services LLC – Monument Gas Plant



SSM FLARING ADDENDUM

Targa appends the Four-Factor Analysis for Monument Gas Plant with the following additional information on process and SSM flaring at Monument Gas Plant as requested in Liz Bisbey-Kuehn's November 14, 2019 emailed letter titled "Submittal Requirements for Process Flaring and Startup, Shutdown, and Maintenance (SSM) Flaring as part of the Regional Haze Four-Factor Analyses".

In Targa's original Four-Factor Analysis report submitted on October 31, 2019, flaring associated with F-03, Acid Gas Flare, was discussed in Section 1.1.2. As such, we do not intend to include additional information about this flaring. Targa maintains that the redundant compression unit to be installed by December 30, 2020 constitutes effective emission control technology to meet emission reductions required under the Settlement Agreement and therefore, does not require additional review.

Table 1A below shows the flare emission rates permitted in the current NSR permit for Monument Gas Plant.

Table 1A. Summary of Flaring Emissions at Monument Gas Plant.

Unit	Equipment	NO_X (lb/hr)	NO_X (tpy)	SO_2 (lb/hr)	SO_2 (tpy)
F-01	Plant Flare (Allowable Emissions)	0.083	0.36	0.004	0.018
F-01	Plant Flare (Allowable SSM Emissions)	522.4	5.1	0.004	0.02
F-02	Emergency Flare (Allowable Emissions)	0.083	0.36	0.004	0.018
F-02	Emergency Flare (Allowable SSM Emissions)	631.0	2.0	6,865.3	17.5
F-03	Acid Gas Flare (Allowable Emissions)	0.083	0.36	0.004	0.018
F-03	Acid Gas Flare (Allowable SSM Emissions)	68.4	10.7	5,817.5	899.1[1]

Targa does not have process streams that vent to flare during normal operations. Targa's authorized flaring is associated with startup, shutdown, and maintenance (SSM) events. As required under 20.2.7.14, Targa developed and implemented a plan to minimize emissions during routine and predictable startup, shutdown, and scheduled maintenance through work practice standards and good air pollution control practices. Targa has followed these requirements while continueing to look for ways to reduce and minimize emissions at the Monument Gas Plant.

Targa minimizes emissions during startups, shutdowns, and maintenance activities through the use of industry standards and/or manufacturer recommended operating practices. In addition, equipment at the facility is equipped with safety devices that will aid in minimizing excess emissions during non-routine operating conditions. The following summarizes Targa's operational plans for minimizing excess emissions.

[1] Permit amendment for redundant AGI compressor has not been submitted and will lower annual PTE for SSM emissions significantly from EPN F-03. See Section 1.1.2 of Monument's Four-Factor Analysis Report submitted 10/31/2019.

After reviewing options for minimizing emissions associated with flaring at Targa's Monument Gas Plant, Targa has not identified any new options to lower flared emission rates beyond what it is already doing. Below is a more detailed explanation of what Targa already does to minimize emissions at the gas plant.

1.1. MAINTENANCE

Targa takes a pro-active approach to facility and equipment maintenance. Operations personnel are aware of the importance of proper and efficient operation of equipment. Moreover, Targa recognizes the economic incentives to maintain and operate equipment efficiently. Malfunctioning equipment wastes resources and costs money.

Equipment at the facility is maintained in accordance with manufacturers' recommendations, industry best operating practices, and Targa's own practices designed to minimize downtime and non-routine operations. Procedures exist for maintenance of each major piece of equipment; personnel are trained in proper procedures; and Targa's own internal review processes ensure that procedures are followed. As a result, non-routine operational events and consequent excess emissions are minimized.

1.2. STARTUP AND SHUTDOWN

Targa's Monument Gas Plant is shutdown annually, in conjunction with required third party pipeline maintenance outages. During this downtime, Targa conducts annual inspections and maintenance of its equipment to minimize downtime. However, due to the nature of oil and natural gas production, natural gas production rates cannot be easily turned on and off when a gas plant needs to be offline for maintenance activities. When natural gas cannot be processed, the gas must be vented or combusted.

During startup of the gas plant some flaring is necessary and cannot be avoided. The first processing step at the plant involves removal of carbon dioxide (CO_2) and hydrogen sulfide (H_2S) followed by the removal of water from the gas. This processing is necessary because Monument utilizes a cryogenic process to split out methane from the heavier hydrocarbons found in raw natural gas. The cryogenic process operates at approximately -150°F. Due to this very cold temperature, the gas must meet very low specifications for water, CO2 and H2S content. Additionally, the natural gas, methane, produced from the cryogenic process must meet several specifications for BTU value as well as ethane content prior to the pipeline accepting the gas.

During startup, the gas will not initially meet the specifications required to go onto the next step in the process. Therefore, there is a period of time flaring of the gas prior to being able to introduce it into the next step of the process. Therefore, the gas must be flared initially until the stream reaches the specifications and can be routed to the next step in the process.

1.3. MINIMIZING EMISSIONS

To reduce emissions during equipment shutdowns for maintenance or operational outages, procedures are designed to minimize the duration of events. Such procedures include the following:

- Compression and other operational loads may be shifted to other units.
- Maintenance may be scheduled for periods of low load.
- Use of spare equipment to maintain operating rates during routine maintenance downtime of certain equipment, like natural gas fired engines.
- Multiple maintenance activities may be scheduled to occur simultaneously.
- Gas may be routed to other nearby gas plants.

- Producers may be asked to shut-in production to minimize gas flow to the plant.
- Startup is conducted with lower H_2S gas streams. Higher H_2S streams are not introduced to the gas plant inlet until the plant is operating normally.
- Compressors are first blown down to lower pressure process equipment prior to venting to reduce volume of process gas emitted (for example blowdown higher stage compressors to first stage suction at approximately 5 psig rather than venting from operating pressure that can be over 100 psig).
- Startup procedures for the turbines and engine are normally completed in less than five minutes, and shutdown procedures are normally completed in less than two minutes.

Targa believes the Monument Gas Plant already utilizes efficient processes and mitigation strategies to reduce flaring emissions through the use of an acid gas injection system as well as by the techniques explained in this addendum. Targa is not aware of control technology that could further reduce emissions from the gas plant.

Permitting Administrative Multi-Form

Use for NSR administrative permit revisions (including GCPs), TV administrative amendments, TV responsible official notifications, and other submittals required by a permit condition. Refer to Section 4 for instructions, acronyms, and mailing addresses.

RECEIVED
MAY 31 2024
Air Quality Bureau

Mail Application To: New Mexico Environment Department Air Quality Bureau 525 Camino de los Marquez, Suite 1 Santa Fe, New Mexico, 87505 Phone (505) 476-4300 Fax (505) 476-4375 www.env.nm.gov/aqb		For Department use only – Received Date: ☑ Approved ☐ Completed ☐ Denied Permit revision number: Reviewed by & date: Jim Kellerson 6-24-24

Section 1: General Information – Required for All Submittals

1	Facility Name: **Saunders Gas Plant**		
2	Preparer/Consultant Name: **Robert Andries**	Title: **Senior Environmental Specialist**	
3	Email: **randries@targaresources.com**	Phone: **(713) 584 – 1360**	
4	Address: **811 Louisiana Street, Suite 2100, Houston, TX 77002**		
5	Air Permit Contact: **Robert Andries**	Title: **Senior Environmental Specialist**	
6	Email: **randries@targaresources.com**	Phone: **(713) 584 – 1360**	
7	Address: **811 Louisiana Street, Suite 2100, Houston, TX 77002**		
8	Check all boxes below for which this submittal applies:	AI #: **612**	Permit #: **0315M5 (NSR)** **P111-R3 (TV)**

☒ NSR Construction Permit (20.2.72 NMAC) ☒ TV Operating Permit (20.2.70 NMAC)	☐ NOI (20.2.73 NMAC) (Sections 2-B, 2-D) ☐ Notice of Exemption (20.2.72.202.B NMAC) (Section 2-F)	☐ PSD Permit (20.2.74 NMAC) ☐ Nonattainment Permit (20.2.79 NMAC)

Section 2: Details of Submittal

Only print and submit the pages necessary for your submittal. Print double sided head-to-toe, flip on short end (tablet). The Permit Section responds to all TV Administrative amendments and responds only to denials of NSR administrative revisions. Courier proof of delivery is required if you want confirmation that the Department received this submittal. Check the box(es) applicable to this submittal:

☐ 2-A(i) & 2-A(ii): Identical Engine or Turbine Replacements

☐ 2-B: Owner, Operator, and Name Changes to NOIs or Construction Permits

☐ 2-C: Ownership or Operational Control Changes for Title V Permits

☒ 2-D: Closing a Facility or Removing Units from a Permit or Canceling an NOI

☐ 2-E: Correct Typographical Error

☐ 2-F: Reporting Exempt Equipment for Minor Construction Permits or for No Permit Required (NPR) Facilities

☐ 2-G: Add Minor NSR Exempt Equipment to Construction Permits for PSD or Nonattainment Sources

☐ 2-H: Title V Responsible Official Designations

Section 3: Certification – Required for All Changes Section 4: Form Instructions

Section 2-D: Closing a Facility, Removing Units from a Permit, or Canceling an NOI

(Administrative Revision)

Check the appropriate boxes and provide complete information in the table. Closing the permit does not relieve the permittee from any outstanding permit fees.

If any of the units being removed are emission control equipment explain how a permit, federal regulation, or state regulation will not be violated by removal of the control equipment.

☐ Cease operations of the entire facility and close the construction permit (20.2.72.219.A(1)(c) NMAC).

Date the facility ceased operating:

☒ Retire an emissions unit and remove it from the construction permit (20.2.72.219.A(1)(c) NMAC).

Date unit(s) retired: **01/01/2021**
List all retired unit numbers to be removed from the permit: **A-01, C-01, C-02, C-03, C-04, C-05, C-06, C-07, C-08, C-09, F-01, F-03, G-01, G-02, G-03, and I-01**

☐ Close a construction permit for a facility or remove an emissions unit that has not and will not be constructed (20.2.72.219.A(1)(d) NMAC).

☐ Facility (plant) will not be constructed, or	☐ The following units will not be constructed and should be removed from the permit:

☒ Retire an emissions unit and remove it from the TV permit (20.2.70.404.A(1)(c) NMAC).

Date unit(s) retired: **01/01/2021**
List all retired unit numbers to be removed from the permit: **A-01, C-01, C-02, C-03, C-04, C-05, C-06, C-07, C-08, C-09, F-01, F-03, G-01, G-02, G-03, and I-01**

☒ Voluntary Discontinuation of the TV permit (20.2.70.400.I NMAC).

Explanation: **With the retirement of the equipment specified above, Targa has determined that the facility will have a potential to emit and actual emissions below Title V Major source thresholds and will no longer require a Title V permit to operate.**

☐ Close a construction permit that is no longer required.

Explanation:

☐ Removal of minor NSR exempt equipment.

Explanation:

☐ Cancel a Notice of Intent (check one or explain):

☐ PER is now below 20.2.73.200 NMAC threshold.	☐ Date the facility ceased operating:

Section 3: Certification – Required for All Submittals

Company Name: Targa Midstream Services, LLC

I, Jimmy Oxford, hereby certify that the information and data submitted in this application are true and as accurate as possible, to the best of my knowledge and professional expertise and experience.

Signed this 29th day of May, 2024, upon my oath or affirmation, before a notary of the State of Texas.

Signature[1] Date: 5/29/24

Jimmy E Oxford — Printed Name

VP Operations — Title

Scribed and sworn before me on this 29th day of May, 2024.

My authorization as a notary of the State of Texas expires on the 13th day of March, 2026.

Notary's Signature Date: 5-29-24

Notary's Printed Name

NEIL P CONWAY
Notary ID #129737310
My Commission Expires
March 13, 2026

[1] For Title V applications, the signature must be of the Responsible Official as defined in 20.2.70.7.AE NMAC:

REGIONAL HAZE FOUR-FACTOR ANALYSIS ADDENDUM

Targa Midstream Services LLC
Eunice Gas Plant
Monument Gas Plant
Saunders Gas Plant

Prepared By:

TRINITY CONSULTANTS
9400 Holly Ave.
Building 3, Suite 300
Albuquerque, NM 87122
(505) 266-6611

February 2020

Project 193201.0194

Environmental solutions delivered uncommonly well

Targa Midstream Services LLC (Targa) appends the Four-Factor Analysis for Eunice Gas Plant, Monument Gas Plant and Saunders Gas Plant with the following information requested by Kerwin Singleton's December 23, 2019 emailed letter titled "Request for Additional Information on Four-Factor Analysis under the Regional Haze Program." In addition, this submittal includes the SSM Flaring Addendum that NMED requested for the Saunders Gas Plant.

INTRODUCTION

In supplementing, at NMED's request, Targa's original four-factor analysis reports submitted on October 31, 2019, Targa wishes to re-assert as an initial matter that emissions from its facilities are unlikely to impact Class I areas at all. The NMED did not consider actual contribution to visibility impairment when selecting sources for the Four-Factor Analysis, but this is a critical factor in establishing realistic reasonable progress goals for Class I areas. As demonstrated in Section 1.1.1 of Targa's original reports, the location of Targa's facilities and meteorology make it unlikely that potential emissions could impact Class I areas. Therefore, when balancing retrofit costs and visibility improvements, NMED should remain mindful that emissions reductions from Targa's facilities are unlikely to contribute to improvement in regional haze at Class I areas.

RESPONSE TO FOUR-FACTOR ANALYSIS QUESTIONS

Please find below Targa's response to questions from the NMED December 23, 2019 letter on the Four-Factor Analysis reports that Targa submitted on October 31, 2019 for the Monument, Eunice, and Saunders Gas Plants.

1. Overarching (for all 3 facilities)

a. Please provide the electronic spreadsheets used to determine the costs of control technologies for all three facilities for all sources subject to the four-factor analysis.

Targa has included a CD with copies of the Excel spreadsheets used in the Four Factor Analyses for the three plants.

b. Flaring: Please provide the following information for the flares at the Targa facilities with emission limits of NOX and/or SO2 greater than 10 pounds per hour (pph) and equal to or greater than 5 tons per year (tpy): Monument Gas Processing Plant F-01, F-02, F-03; Eunice Gas Processing Plant F-01 and F-02; Saunders Gas Processing Plant F-01.

i. If not already provided in the SSM Flaring Addendum submitted on December 13, 2019 from the Eunice and Monument gas plants, please provide a description of each flare and all of its purposes.

Facility	Flare Unit No.	Description
Monument Gas Plant	F-01	Process flare used during maintenance or upset events within the facility to control residue gas (pipeline quality natural gas). Flare meets 40 CFR 60.18 requirements with a 98 % destruction efficiency.
	F-02	Process flare used during maintenance or upset events within the facility to combust inlet gas. Flare meets 40 CFR 60.18 requirements with a 98 % destruction efficiency.
	F-03	Process flare used during AGI well maintenance or upset events within the facility to combust acid gas. Flare meets 40 CFR 60.18 requirements with a 98 % destruction efficiency.
Eunice Gas Plant	F-01	Process flare used during AGI well maintenance or upset events within the facility to combust acid gas. Flare meets 40 CFR 60.18 requirements with a 98 % destruction efficiency.
	F-02	Process flare used during maintenance or upset events within the facility to combust inlet and residue gas. Flare meets 40 CFR 60.18 requirements with a 98 % destruction efficiency.
Saunders Gas Plant	F-01	Process flare used during SRU maintenance or upset events when the SRU is not operating to combust acid gas. Flare meets 40 CFR 60.18 requirements with a 98 % destruction efficiency.

ii. Provide the startup, shutdown, and maintenance plan required by 20.2.7.14 NMAC that was mentioned as the existing and only method and that is currently implemented to reduce SSM flaring emissions, including any equipment maintenance and training plans used to prevent outages. According to the December 13, 2019 submittal, there are no other alternatives to reducing emissions other than that is required by 20.2.7.14 NMAC. If it is not possible to make any improvements to the facility or its processes to reduce SSM flaring events, then please explain why.

Targa is commercially and economically incentivized to minimize SSM downtime, and thereby SSM flaring. Further, the AQB's excess emissions reporting rules and enforcement process incentivize Targa to minimize SSM downtime and SSM flaring. Targa's existing O&M policies and SSM Plans were designed and are implemented accordingly. As explained in Targa's SSM Flaring Addendums (and in Section 4 of this submittal for the Saunders Gas Plant), Targa takes a number of steps to prevent and reduce SSM flaring, and Targa's practices comply with NMED's "minimize emissions" requirements in 20.2.7.14 NMAC. That said, it is infeasible to completely eliminate SSM downtime and SSM flaring emissions—indeed, Targa has represented expected SSM emissions in permit applications and the AQB authorized those emissions.

Targa's SSM plans are attached to this submittal in Appendix B.

iii. List and describe all of the reasons that trigger each type of flaring event. This is to identify and clarify the causes to help find potential solutions to reduce flaring emissions.

Please refer to Targa's SSM Flaring Addendums, Section 4 of this submittal (Saunders Gas Plant), and the table in Section b.i. above.

iv. Include a discussion of any potential alternative control options or operational changes that could reduce flaring NO_X and/or SO_2 emissions, including but not limited to:

a. infrastructure that allows recovering and re-routing or recirculating the gas within the facility or outside of the facility until an SSM event is over;

This option is outside the scope of the haze analysis. The regional haze planning process should result in establishment of emissions limitations or other limitations (40 C.F.R. 51.308(f)(2)) that may be met by applying retrofit technologies or practices to an existing source, not redefining a source. *See* 40 C.F.R. Part 51, App. Y ("We do not consider BART as a requirement to redesign the source when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, we do not require the BART analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting on a per unit basis."). As demonstrated below, this option would completely redefine the gas processing plants.

Rerouting gas volumes to other facilities is currently in place when a facility has an SSM event. However, inlet gas to a facility cannot be diverted or routed directly to a sales meter or transmission pipeline (bypassing the facility) due to contaminants in the inlet gas such as water, CO2, H2S, and heavy liquids. Sales pipelines cannot and will not take inlet gas unless it meets certain specifications. Inlet gas cannot be recirculated back to the producer or field system. Producer gas continues flowing until high pressure limits of equipment and/or pipe is reached, resulting in flaring or physically shut-in gas at the well head.

As stated above and in the SSM flaring addendums, the current operating system will route gas to other nearby gas plants when possible during SSM or upset events.

b. sulfur absorbent technology used to remove sulfur from pipelines and other auxiliary equipment to reduce inlet or plant flaring SO_2 emissions;

Targa already utilizes sulfur absorbent technology, amine, to remove H_2S and CO_2 from the inlet gas. Targa's Four Factor Analysis did not include selective chemical absorption where the H_2S remains in the liquid and disposed as hazardous waste. Non regenerative chemical absorbent technology is not designed for high volumes (100 MMSCFD) or high H_2S concentrations. When there are both high volumes and high H_2S concentrations, the amount of chemical absorbent needed is extremely high and it is technically infeasible to store the amount of absorbent needed on a daily basis or the ability to replenish the spent chemical to remove H_2S from the stream. A gas plant is a gathering system of wells that all converge in a pipeline to the facility. This technology was designed to use on a much smaller scale than a gas plant.

c. Gas Capture Plans with facilities located downstream and upstream similar to those required for producers to better synchronize upstream and downstream services with the Targa facilities;

As the question implies, New Mexico's rules do not require midstream companies to maintain gas capture plans. Requiring Targa to maintain a gas capture plan would not reduce flaring at its

gas plants for at least three reasons. First, Targa already coordinates with upstream producers and downstream pipelines to plan for scheduled outages, and so further coordination requirements would be duplicative and not cost effective. Second, scheduled maintenance, unexpected equipment malfunctions, or third-party power outages are the typical cause of gas plant flaring—not upstream or downstream coordination problems. Third, gas capture plans are only required for producers and may reduce well site flaring. The outcome of the regional haze process, however, should be an enforceable emissions limitation or other limitation at the source under review, and gas capture plans can neither be converted into an enforceable limitation nor reduce flaring at the source under review (i.e. gas plants).

d. use of remote capture equipment;

A remote gas capture system is a small gas plant (produces NGLs). Targa is unaware of this technology ever being "proven" for use at a gas processing plant. For that reason alone, Targa considers this technology infeasible. 40 C.F.R. Part 51, App. Y (regarding how to identify available retrofit emission control technologies, stating "[t]echnologies which have not yet been applied to (or permitted for) full scale operations need not be considered as available; we do not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice.").

For Targa's gas plants in particular, using this technology would be technically infeasible for 100 MMSCFD gas plants due to the size and H_2S content of the gas. In addition, when a downstream facility has a malfunction, Targa is unable to send gas or NGL liquids to the outlet pipelines. In these instances, especially, a gas capture system would not work since there would be no place to send the gas or liquids downstream.

Further, the regional haze analysis focuses on the source under review (Targa's gas plants), and not interconnected sources (upstream oil and gas wells). The NMED's Draft Methane Advisory Panel Report, for example, assesses the use of remote capture equipment only for upstream operators. As that report notes, well sites may have the space for this equipment as well pads designed for hydraulic fracturing will have additional space become available when well pad equipment is removed. Further, upstream operators may be able to deploy this technology knowing that there will be a reliable stream of "shut-in" gas to be captured, such as when buildout of a gathering system is delayed. This investment would be infeasible for a gas processing plant that goes to flare during limited SSM periods.

e. better infrastructure planning and changes to existing infrastructure that connects the downstream and upstream operations to ensure that there is adequately processing capacity to move produced gas to market.

Targa does not and cannot control upstream infrastructure planning. This process is largely driven by upstream operators and regulatory agencies such as the NMOCD, the N.M. State Land Office, and the Bureau of Land Management. For its part, Targa has adequate infrastructure for connecting and continues developing infrastructure to connect downstream and upstream operations in New Mexico. Thus, Targa already has the infrastructure in place to adequately process and move produced gas to market while mitigating flaring emissions as much as possible.

v. For any technically feasible solutions, provide a four-factor analysis. For additional information regarding potential alternative controls to flaring see the New Mexico Methane Strategy.

Targa has been involved in the development of the New Mexico Methane Strategy. For example, Targa's Director of Air Permitting gave a technical presentation to the Methane Advisory Panel on natural gas dehydration units. To date, that Panel has only produced a *draft* technical report that includes discussion of addressing flaring and venting in New Mexico. Targa reviewed the draft report and did not see any midstream-specific NOx or SO_2 solutions that should be considered technically feasible for a four-factor analysis.

c. Engines: Please provide the following information for all engines that were evaluated in the Four-Factor Analysis for NO_X:

Targa is providing the requested information below. However, as an initial matter, note that NMED has presented information identifying ammonium sulfate as the largest contributor to visibility impairment in New Mexico's National Parks. Ammonium sulfate is a byproduct of gaseous sulfur dioxide which becomes oxidized in the atmosphere to form sulfate particulate matter. This information indicates that the major contribution to regional haze is from sulfur dioxide emissions, not nitrogen dioxide emissions. Thus, NMED should ensure that any required NOx reductions show significant contribution to improving visibility prior to requiring capital expenditures. Because emissions from Targa's facilities are not expected to impact visibility in Class I areas, any technically feasible NOx controls are economically unreasonable.

i. Natural gas-fired two-stroke lean-burn (2SLB) engines from the three gas plants have widely varying emissions rates and control efficiencies. Please explain why there are such large differences for engines that are the same make, model, and horsepower.

The cost analyses submitted to the NMED on October 31, 2019 were based on 2016 actual emissions. Actual emissions were calculated based on 2016 hours of operation multiplied by the stack tested emission rate. With regards to the engine usage, Targa attempts to use its engines uniformly but this does not mean equally on a calendar year basis. The annual hours of operation will depend on various factors. The main reasons may be a unit's service availability (is it working or not), or if the unit requires scheduled maintenance (i.e. the unit may be scheduled to be swapped with an identical unit). As such, each year the engines will operate with different hours of operation and fuel usage. Since the NMED requested 2016 actual emissions be used in the cost analysis, the cost calculations for each unit will have varying emission totals which creates varying costs per ton for identical engines. Per AP-42 Section 3.2.3 "It is not unusual to test emissions from two identical engines in the same plant, operated by the same personnel, using the same fuel, and have the test results show significantly different emissions. This variability in the test data is evidenced in the high relative standard deviation reported in the data set." Stack tests are a snapshot in time and only provide potential emissions based on that snapshot. See the included Excel spreadsheets for details on the emission rate calculations.

ii. Targa states that some compressors that were previously powered by natural gas-fueled engines used at the Eunice Gas Processing Plant were replaced with compressors powered by commercial electric power. Please consider and include a discussion on the feasibility of replacing more natural gas-fueled engines with commercial electric powered compressors at Eunice and other facilities.

The regional haze planning process should result in establishment of emissions limitations or other limitations (40 C.F.R. 51.308(f)(2)) that may be met by applying retrofit technologies or practices to an

existing source, not redefining a source. *See* 40 C.F.R. Part 51, App. Y ("We do not consider BART as a requirement to redesign the source when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, we do not require the BART analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting on a per unit basis."). Thus, replacement of one source (natural gas-fired engines) with another (electric compression) is beyond the scope of the regional haze analysis.

Further, Targa is unable to add additional electric driven compression to Monument or Eunice without significant investment in electrical infrastructure at the sites. Electrical substations would need to be built at the Eunice and Monument Gas Plants. In addition, the power to the plants would need to be upgraded by the electrical provider. Saunders Gas Plant currently generates power from on-site generators.

iii. Consider and include a discussion of variations of Clean Burn Technology (CBT) used to reduce NO_X emissions that may be less expensive than the full CBT packages proposed. Please include cost and efficiencies in the analysis.

Targa has provided an updated cost analysis for Clean Burn Technology on the Cooper Bessemer engines showing an optional NO_X reduction to 5 g/hp-hr as an alternative to the 2 g/hp-hr reduction provided in the original analysis. To meet 5 g/hp-hr the engines would need to add a pre-combustion chamber with power cylinder heads, modification to the fuel system, a turbocharger system, and combustion air intercoolers with jacket water. To meet 2 g/hp-hr, the same equipment would need to be installed to meet the base reduction plus an additional intercooler water circuit radiator and electric motor driven water pump to operate a lower temperature water system for air cooling.

Please note, some units tested below 5 g/hp-hr for 2016 and are not included in this updated control analysis. Also, unit C-03 at Eunice had incorrect emissions reported in the 2016 Emission Inventory. The correct emission rate should be based on 14.192 g/hp-hr, the 2015 performance test on the engine. See further discussion in 3.b. This cost analysis is attached to Appendix A.

iv. Please provide vendor quotes that include the cost information, recommendations, and equipment specifications for the engine control cost estimates.

Targa has included the requested vendor cost estimate, recommendations, and equipment specifications in Appendix B. This appendix has been marked confidential and included separately as vendor data is confidential.

v. Provide the technical basis for the "historical precedent that installation of SCR on two-stroke lean-burn (2SLB) engines can result in significant technical complications, require deration of engines, and unreliable operation post-retrofit" statement.

Selective catalytic reduction technology has not been applied successfully to 2SLB engines. After researching SCR controls on 2SLB engines, the EPA document titled "Technical Issues Related to the Potential Use of Selective Catalytic Reduction (SCR) to Reduce NOx Emissions from Natural Gas-Fired Lean Burn Engines" is the only document found with information on the application of SCR's on 2SLB engines. This documentation shows that many units did not perform properly after SCR was installed. Targa was unable to find any historical installation of SCR on 2SLB engines in the RLBC tables. The only proven technology to control NO_X for 2SLB engines is Clean Burn Technology. This is also the technology recommended by the engine control vendor to control NO_X for the units at Targa's three gas plants.

When completing BACT analyses and even in the BART requirements under 40 C.F.R. Part 51, App. Y, the EPA only requires analysis for technologies that have been proven. 40 C.F.R. Part 51, App. Y (regarding how to identify available retrofit emission control technologies, stating "[t]echnologies which have not yet been applied to (or permitted for) full scale operations need not be considered as available; we do not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice."). As such, this is the definition Targa used to analyze equipment for this report.

vi. Provide the basis for the operational and maintenance (O&M) costs used in the cost analyses.

The O&M cost included in the analyses were based on Targa's experience operating similar control devices at other sites for expected maintenance and repair. Targa intends to conduct recommended maintenance per manufacturer.

vii. Explain why the air-to-fuel ratio adjustments for 2SLB engines varies so much depending on the specific engine and typical loading (e.g. 5% to 30% reduction).

The air-to-fuel ratio information was obtained in a document titled "State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines from the State of New Jersey."[1] This document contained the range for the air-to fuel-ratio used in the original submittal.

viii. Provide an explanation for the need to upgrade the power substations at the Monument Gas Processing Plant and the Eunice Gas Processing Plant to operate blowers for the proposed CBT.

Targa is unable to add any further high-power electrical equipment to the sites without significant modifications to the facilities' power substations. As stated in the original submittal, Eunice and Monument Gas Plants would need to add a substation in order to operate more electric units as well as contract more power from the power company. Not only is this expensive, but the power the facility currently receives has been unreliable at times, especially at Eunice Gas Plant. The electricity currently used to operate Eunice Gas Plant has voltage fluctuations and voltage spikes. This causes units to shutdown or malfunction when these conditions occur. A partial loss of power or voltage spike (voltage fluctuation) has the same effect as total loss in that it will cause high power electrical equipment to automatically shutdown to avoid equipment damage.

ix. Typically, under the Regional Haze process, a time period of two to five (2-5) years is assumed to be reasonable for the installation of controls; therefore, an estimate of seven (7) years to install CBT on the 2SLB engines at your facilities seems excessive. Please detail the reason for the long compliance times and whether there are ways to reduce compliance times and installation.

The time period Targa included to install controls on the facility's 2SLB engines was based on an estimate for installing controls for all 2SLB engines located at Eunice, Monument and Saunders Gas Plants. This would require installing CBT for a combined 30 units. The timeline of 7 years allows Targa 5 years to install 30 units plus 2 years to conduct engineering design work and obtain the air permits.

Below is a breakdown of our estimate for 7 years.

[1] https://www.state.nj.us/dep/aqpp/downloads/sota/sota13.pdf

- Engineering design work is estimated to take 3 months.

- An air quality permit will need to be obtained before installing the modifications. Typically, an air permit application takes 1-2 months to prepare and the permit application, once submitted, will take 9 to 12 months to receive.

- Concurrent to obtaining the air permit, Targa would also need to prepare an engineering schedule and complete final design work on the installations and order long lead-time equipment to install the controls on each unit.

- Targa would need to obtain a new contract with the electric company for the additional power. The electric company would need to build a substation and potentially run additional lines to the plant. This assumes the electrical company can provide the additional power needed within the required timeline. This is unknown at this time.

- Installation could begin once the air permit was issued and equipment was delivered. Installation of the substation would need to occur first so power would be available to run the CBT. This is estimated to take up to a year due to long lead time of equipment.

- Startup of the first set of CBT controls would take approximately 24-30 months. Assuming installation of up to 6 units a year would spread out installation over 5 years. In order to install the controls, once the control equipment is installed, the engines will have to be taken out of service for approximately 2 weeks to hook up the additional control equipment to the engine. Installing 6 units per year allows for the engineering construction crew to move from one engine to the next in an orderly fashion since there will be reduced gas processing rates through the plants during shutdown of the unit for control installation.

x. Please provide the details regarding Good Combustion Practices (GCP) and the routine maintenance schedule and procedures that are currently used to mitigate NO_X emissions and are proposed as a feasible control.

On all engines Targa operates, specific job plans are developed from the original equipment manufacturer (OEM) recommended maintenance procedures. They are done on OEM recommended intervals and are tracked in Targa's Maximo maintenance tracking system. The operators also make daily rounds and record exhaust temps. Temperatures are used to plan maintenance on the units.

2. Monument Gas Processing Plant

a. Sour Gas Amine Treating Units / Flare:

i. Describe why the Amine Treating Unit / Flare emissions for 2016-2017 are approximately 2,000 tons SO2. Was there a malfunction in the acid gas injection well (AGI) process? Describe the current emissions rate, current status of operations and why there are no further control options evaluated other than the AGI.

Targa's Monument AGI well failed an OCD required pressure test on July 27, 2016. Targa shut down the AGI well on August 8th to attempt to repair the well and began flaring acid gas. However, the well repair was unsuccessful and the well had to be plugged and abandoned. Targa drilled a new well immediately and the well became fully operational in March 2017. This was an unexpected failure of the AGI well after only 5 years of service. Since most of these emissions were caused by an upset condition, calendar year 2016 and 2017 actual emissions would not be a reasonable emission rate to use for Regional Haze

review. Targa maintains that no further review should be required for the amine unit at the Monument Gas Plant under the Four Factor Analysis as an AGI well with redundant compression constitutes effective emission control technology of H_2S and SO_2 emissions.

ii. Describe how the addition of a redundant compressor will increase the control efficiency of the AGI system.

The addition of the redundant compressor will reduce the number of hours that the AGI system is offline for maintenance and upset conditions, thus reducing the amount of SO_2 emitted during flaring of the acid gas. The AGI system currently must be taken offline for maintenance of the AGI compressor, which is used to increase the acid gas to the pressure necessary for injection into the AGI well.

iii. Are there additional ways of optimizing performance of the AGI system in addition to redundant compression?

Targa is spending approximately $7,000,000 to install redundant compression, and this was done to settle an AQB enforcement case, not as part of meeting BACT-based emission limits. Targa has not identified any technically feasible control alternatives to further optimize performance of the AGI system.

3. Eunice Gas Processing Plant

a. Amine Unit Controls: Include a discussion of alternative control methods, other than redundant acid gas injection (AGI) for amine units, such as sulfur recovery units (SRUs).

In Settlement Agreement Number AQCA 09-00(CO) issued by the NMED, Targa was required to shutdown the SRU and incinerator at the Eunice Gas Plant and install an AGI well. In addition, Targa believes that an AGI injection system with redundant compression as required under Settlement Agreement ABQ TAR-0610-1701(NOV) is effective emission control as defined in the Regional Haze rules. Targa has not identified any technically feasible control alternatives.

b. Engines: For Engine Unit C-03, provide the origin of the 5.13 g/hp-hr NOx emission factor used in baseline emissions calculations instead of the performance test results of 14.192 g/hp-hr.

This was an error in the 2016 emissions inventory. The 2015 performance test for C-03 was not used to calculate 2016 emissions on the engine. Targa has updated the emission rate calculations for this engine in our analysis and the cost effectiveness has been updated based on the performance test results of 14.192 g/hp-hr.

c. Steam Generating Boilers: Units B-01 and B-02.

i. Please provide details of the GCP and the associated routine maintenance schedule and procedures that are currently used to mitigate NO_X emissions and are proposed as a feasible control for the Boilers.

Specific job plans are developed from the original equipment manufacturer (OEM) recommended maintenance procedures. They are done on OEM recommended intervals and are tracked in Targa's Maximo maintenance tracking system. The operators also make daily rounds on the units.

As part of the maintenance program of these boilers, Targa conducts an efficiency study every 5 years per 40 CFR Part 63, Subpart DDDDD.

ii. Provide vendor specifications that include the cost information, recommendations, technical feasibility/infeasibility basis, and equipment specifications for the boiler control estimates.

Vendor information is provided in Appendix B. This information is business confidential information.

iii. Consider and include a discussion of the feasibility of staged combustion techniques, peak flame temperature reduction, water/steam injection, fuel-induced recirculation (FIR), and natural gas reburning (NGR) to reduce NOx emissions.

The option recommended by the boiler control vender to reduce NO_X emissions is to add flue gas recirculation (FGR) to the boilers. Other options, including the options listed above, will require major modifications to the boilers. FGR requires the least amount of modification to the boilers. These boilers were manufactured in the 1950's and not designed with add-on controls in mind. Installing controls on a unit never designed with controls in mind has a high potential to affect runtime, reliability, and will require increased maintenance. The boilers provide heat to the amine unit. With a higher amount of downtime on the units, this will cause associated flaring since sour gas cannot be processed without the amine system to remove CO_2 and H_2S. This will likely result in negatively offsetting the NO_X reductions from additional control technology.

Per our consultant, staged combustion is typical for burner types that are air staged, similar to the Eunice burners, or fuel staged. To do deeper air staging, the boiler sidewalls would need modification as the A frame style boilers to not lend themselves to deep air staging. Therefore, this is technically infeasible.

Peak flame temperature reduction is how NO_X emissions are reduced but is not a specific control technology. However, this is typically done through flue gas recirculation (FGR) or fuel induced recirculation (FIR). Per our consultant, FIR requires modification of the burners to accept the mixing of flue gas with the fuel. This method requires very precise method of mixing the flue gas with the fuel. If not designed well, burner acoustics will occur. This technology also requires higher fuel gas pressures. Due to the precise modifications that would need to be made to these 1950 vintage boilers and likelihood of burner acoustics, Targa determined this technology to be technically impractical. Targa has already provided information on FGR technology on the boilers. See original Four Factor Analysis.

Steam injection was determined to be technically impractical for a number of reasons including that the boiler furnaces were not designed for water and high purity water is not available. As a result, this technology would significantly increase maintenance downtime for cleaning and inspections due to scaling on the outside of the tube bundles. Additional NO_X emissions would be generated from the increased firing rate of the boiler to accommodate the additional steam requirement for injection. Scaling would decrease fuel efficiency of the boilers increasing the firing rate as well. This would result in higher NO_X emission from the boilers, offsetting the reductions from the control technology.

NGR was not considered for these units as it is applicable to boilers burning coal, wood or heavy oils. The Eunice boilers are natural gas fueled.

iv. Supplement the technical analysis that eliminated selective catalytic reduction (SCR) as technically infeasible as an add-on NO_X control for the boilers. The reasons given in the analysis for eliminating SCR are that retrofitting SCR controls on boilers is difficult and affects the reliability of the boilers and references the EPA SCR fact sheet. The fact sheet states that retrofitting is difficult but mentions nothing about boiler reliability. The other reason that SCR was eliminated for technical reasons is that SCR takes significant electrical power that would require a significant upgrade to the power system. The cost of upgrading the electric system is not considered at the technical feasibility step.

The boilers were manufactured in the 1950's and installing new technology on a unit never designed with controls in mind has a high potential to affect runtime, reliability, and will require increased maintenance downtime. With a higher potential for downtime on the units, this will cause associated flaring when the units are down and likely result in negatively offsetting NO_X reductions from the control technology. Targa believes installing SCR's on these boilers should be considered technically infeasible. However, Targa has provided the cost per ton to install SCR on the boilers at Eunice. Using the EPA Cost Control Manual estimates $134,021.21/ton for boiler B-01 and $139,853.11/ton for boiler B-02. This cost is not reasonable for this control. These calculations are provided in the electronic files.

v. Why was natural gas reburn (NGR) not included in the discussion?

NGR was never considered for these units as it is applicable to boilers burning coal, wood or heavy oils. These are natural gas fueled boilers.

vi. Provide a summary of the continuous emissions monitoring system (CEMS) data used to provide the emission factors for the boiler baseline calculations.

The boilers do not have CEMS installed and CEMS data was not used. Targa used the most recent stack test available (2008) as the baseline emission factor for the emission inventory. Targa also used this basis for the cost analysis.

vii. Please provide the basis for the total capital investment and annual O&M costs provided by Targa.

On all engines Targa operates, specific job plans are developed from the original equipment manufacturer (OEM) recommended maintenance procedures. They are done on OEM recommended intervals and are tracked in Targa's Maximo maintenance tracking system.

4. Saunders Gas Plant

a. Engines: The analysis states that the emission factors for the baseline emissions calculations for the engines were based on performance tests. Typically, a performance test refers to an initial compliance test using EPA Reference Methods. The Department's records show that this was a periodic portable analyzer test, not what would be called a performance test. Were these the only tests conducted on these units during 2016, or were additional periodic portable analyzer tests conducted? If so, please provide test results of all portable analyzer tests conducted on these engines in 2016.

The portable analyzer tests conducted on the engines that were used for the emission inventory calculations are attached to this addendum in Appendix A.

b. All Four-Stroke Rich-Burn (4SRB) Engines: Table 3., Potential Control Options for 4SRB Recirculating Internal Combustion Engines (RICE) indicates that CBT is technically feasible for these engines, with a NOX control efficiency of 10% - 40%; however, the narrative on the technical feasibility for this technology concludes that, for various reasons, Targa has determined that this method is infeasible for 4SRB engines. Please explain this discrepancy.

The 10% to 40% provided in the table of the original submittal was a typographical error. The table should have stated N/A for 4SRB engines as this technology was determined to be infeasible.

c. All Two-Stroke Lean-Burn (2SLB) Engines: The estimated cost effectiveness for the installation and operation of CBT on the six (6) Cooper Bessemer GMVA-10 engines at the facility varies drastically from

a low of $2,753.99/ton NO_X to a high of $277,724.45/ton NO_X based on performance tests (periodic portable analyzer tests) conducted in 2016. Has Targa conducted an evaluation of these units to determine why the emissions from these identical engines varies so greatly ((2.05 – 10.78 grams NO_X/hp-hr.)? If we assume that that the addition of CBT on unit C-01 is uneconomical at $277,724.45/ton NO_X reduced, the average the cost effectiveness of units C-02 through C-09 is $5,926.01 and would result in an estimated annual NO_X reduction of 279.65 tons. Would Targa be willing to reduce the allowable emission rate for unit C-01 to ensure continued low NO_X emissions from this unit?

The cost analyses submitted to the NMED on October 31, 2019 were based on 2016 actual emissions. The actual emissions were calculated from 2016 hours of operation multiplied by the emission rate from stack testing. With regards to the engine usage, Targa attempts to use its engines uniformly but this does not mean equally on a calendar year basis. The annual hours of operation will depend on various factors. The main reasons may be a unit's service availability (is it working or not), or if the unit requires scheduled maintenance (i.e. the unit may be scheduled to be swapped with an identical unit). As such, each year the engines will operate with different hours of operation and fuel usage. Since the NMED requested 2016 actual emissions be used in the cost analysis, the cost calculations for each unit will have a varying emission totals which will create varying costs per ton for identical engines. Per AP-42 Section 3.2.3 "It is not unusual to test emissions from two identical engines in the same plant, operated by the same personnel, using the same fuel, and have the test results show significantly different emissions. This variability in the test data is evidenced in the high relative standard deviation reported in the data set." Stack tests are a snapshot in time and only provide potential emissions based on that snapshot. See the included Excel spreadsheets for details on the emission rate calculations.

Targa believes it is unnecessary and unwarranted to reduce the allowable emission rate for unit C-01 to ensure continued low NO_X emissions.

d. Amine Treating Unit:

i. How efficient is the amine treating unit at removing H2S and CO2 from the gas stream? Is it technically feasible to add additional stages to the sulfur recovery unit to reduce the amount of sulfur compounds in the tail gas?

The current amine treating unit removes CO_2 and H_2S from the natural gas stream down to very low concentrations, as required to meet pipeline specifications and the low temperatures of the cryogenic unit used to split the methane from the natural gas liquids. The sulfur recovery unit (SRU) meets the NSPS LLL requirement of 74% efficiency in removing sulfur from the acid gas stream. The acid gas stream is the vent gas stream off the amine unit still vent. Additional SRU stages to control SO_2 emissions from the sulfur recovery unit are discussed in d.ii below.

ii. Similarly, as Targa had previously determined that the construction of an acid gas injection well is technically infeasible, is it feasible to have a redundant sulfur recovery unit in order to limit acid gas flaring during maintenance of the primary sulfur recovery unit?

Three different add-on control scenarios for the SRU are provided below to further reduce SO_2 emissions from the SRU and incinerator.

- Add a 3rd bed to current SRU, which would result in a 90% recovery of inlet sulfur. The current system reduces inlet sulfur by 74%.

- Add a redundant SRU, which would result in reducing flaring emissions when the current SRU is down for maintenance.

- Add a tail gas unit after the SRU, which would increase the sulfur recovery to 95% of inlet sulfur.

These scenarios are deemed technically feasible. The cost analysis for these scenarios are shown in the table below.

Control Equipment	Unit	Capital Cost ($)	Total Annual Cost ($)*	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Redundant SRU	I-01	**26,760,000**	**2,489,259**	**25.59**	**97,287.09**
3rd Bed to SRU	I-01	**8,590,000**	**818,805**	**242.97**	**3,369.96**
Tailgas Unit	I-01	**6,850,000**	**2,073,203**	**347.49**	**5,966.28**

*Total Annual Cost includes the annualized capital cost, as well as the direct and indirect annual operating costs.

Targa has received an estimated direct capital costs for the equipment and vendor labor associated with implementing the above changes to the amine system located at Saunders from a consultant who designs the equipment. Based on prior knowledge of the equipment, Targa estimated the direct annual costs (maintenance, operating labor, reagent cost, electricity cost, and catalyst cost) and indirect annual costs associated with Targa's internal labor, overhead and capital recovery for the project.

Cost effectiveness for each scenario are summarized in the Table above. To calculate the emission reductions, Targa used the 2016 Emission Inventory (EI) data. This was compared to the maximum PTE emission rate of the equipment post-control to get an Emission Reduction (tpy) value. The Total Annual Cost was then divided by the Emission Reduction to come up with a Cost Effectiveness ($/ton) amount. The full cost estimation for each unit is included in Appendix A of this report.

The Tailgas Unit would have negative environmental impacts due to the waste generated from the caustic chemical used to control the tail gas SO_2 emissions. This control would have 600 bbl/d of waste that would need to be trucked out and disposed.

Targa estimates that approximately 4 years will be needed to budget, design, procure, authorize, and install either of these types of control equipment if the facility is required to add these controls. The estimated useful life of the SRU equipment is 20 years, based on industry standards for life of the controls.

SAUNDERS SSM FLARING

Additional information on process and SSM flaring at Saunders Gas Plant is included below as requested in Liz Bisbey-Kuehn's November 14, 2019 emailed letter titled "Submittal Requirements for Process Flaring and Startup, Shutdown, and Maintenance (SSM) Flaring as part of the Regional Haze Four-Factor Analyses".

Targa does not have process streams that vent to flare during normal operations. Targa's authorized flaring is associated with startup, shutdown, and maintenance (SSM) events. As required under 20.2.7.14, Targa developed and implemented a plan to minimize emissions during routine and predictable startup, shutdown, and scheduled maintenance through work practice standards and good air pollution control practices. Targa has followed these requirements while continuing to look for ways to reduce and minimize emissions at the Saunders Gas Plant.

Targa minimizes emissions during startups, shutdowns, and maintenance activities through the use of industry standards and/or manufacturer recommended operating practices. In addition, equipment at the facility is equipped with safety devices that will aid in minimizing excess emissions during non-routine operating conditions. The following summarizes Targa's operational plans for minimizing excess emissions. After reviewing options for minimizing emissions associated with flaring at Targa's Saunders Gas Plant, Targa has not identified any new options to lower flared emission rates beyond what it is already doing. Below is a more detailed explanation of what Targa already does to minimize emissions at the gas plant.

MAINTENANCE

Targa takes a pro-active approach to facility and equipment maintenance. Operations personnel are aware of the importance of proper and efficient operation of equipment. Moreover, Targa recognizes the economic incentives to maintain and operate equipment efficiently. Malfunctioning equipment wastes resources and costs money.

Equipment at the facility is maintained in accordance with manufacturers' recommendations, industry best operating practices, and Targa's own practices designed to minimize downtime and non-routine operations. Procedures exist for maintenance of each major piece of equipment; personnel are trained in proper procedures; and Targa's own internal review processes ensure that procedures are followed. As a result, nonroutine operational events and consequent excess emissions are minimized.

STARTUP AND SHUTDOWN

Targa's Saunders Gas Plant is shutdown as needed, in conjunction with required third party pipeline maintenance outages. During this downtime, Targa conducts inspections and maintenance of its equipment to minimize other downtime. However, due to the nature of oil and natural gas production, natural gas production rates cannot be easily turned on and off when a gas plant needs to be offline for maintenance activities. When natural gas cannot be processed, the gas must be vented or combusted.

During startup of the gas plant some flaring is necessary and cannot be avoided. The first processing step at the plant involves removal of carbon dioxide (CO2) and hydrogen sulfide (H2S) followed by the removal of water from the gas. This processing is necessary because Saunders utilizes a cryogenic process to split out methane from the heavier hydrocarbons found in raw natural gas. The cryogenic process operates at approximately -150°F. Due to this very cold temperature, the gas must meet very low specifications for water, CO_2, and H_2S content. Additionally, the natural gas (methane) produced from the cryogenic process must meet several specifications including BTU value and ethane content prior to the outlet pipeline accepting the gas.

During startup, the gas will not initially meet the specifications required to go onto the next step in the process. Therefore, there is a period of time flaring of the gas is necessary prior to being able to introduce it into the next step of the process. Therefore, the gas must be flared initially until the stream reaches the specifications and can be routed to the next step in the process.

Additionally, the sulfur recovery unit (SRU) must be warmed prior to introducing acid gas to the unit. Targa minimizes emissions from SRU startup using hot nitrogen gas to warm up the SRU beds. This allows the recovery of sulfur to be higher once acid gas is introduced into the SRU.

MINIMIZING EMISSIONS

To reduce emissions during equipment shutdowns for maintenance or operational outages, procedures are designed to minimize the duration of events. Such procedures include the following:

- Compression and other operational loads may be shifted to other units.
- Maintenance may be scheduled for periods of low load.
- Use of spare equipment to maintain operating rates during routine maintenance downtime of certain equipment, like natural gas fired engines.
- Multiple maintenance activities may be scheduled to occur simultaneously.
- Gas may be routed to other nearby gas plants.
- Producers may be asked to shut-in production to minimize gas flow to the plant.
- Startup is conducted with lower H_2S gas streams. Higher H_2S streams are not introduced to the gas plant inlet until the plant is operating normally.
- Compressors are first blown down to lower pressure process equipment prior to venting to reduce volume of process gas emitted (for example blowdown higher stage compressors to first stage suction at approximately 5 psig rather than venting from operating pressure that can be over 100 psig).
- Startup procedures for the turbines and engine are normally completed in less than five minutes, and shutdown procedures are normally completed in less than two minutes.
- Using hot nitrogen gas to warm up the SRU bed prior to introducing acid gas.

Targa believes the Saunders Gas Plant already utilizes efficient processes and mitigation strategies to reduce flaring emissions through the use of an acid gas injection system as well as by the techniques explained in this addendum. Additional control technology to reduce SSM flaring is covered in response to 4.d.ii. above.

APPENDIX A: SUPPORTING INFORMATION

ENGINE 2016 PORTABLE ANALYZER TESTS – SAUNDERS
REVISED COST ANALYSES

Saunders Engine Test Reports Omitted for Brevity

Targa Eunice Gas Processing Plant

Eunice Gas Plant

Boiler	Interest Rate:		5.50%	
Unit B-01	Period (yrs):		20	<-- EPA Guidance Default

Base Emissions

NO_X ppm	90	ppm	<-- From client
NOX Rate	73.59	lb/MMSCF	<-- From 11/12/08 test data
Fuel Usage	219.5	MMscf/yr	<-- From 2016 EI calculations
NO_X lb/hr:	1.84	lb/hr	
NO_X tpy:	8.08	tpy	

SCR

NO_X control:	80%	Control Eff.	<-- Assumed for SCR, AP-42 Section 1.4
NO_X lb/hr:	0.37	lb/hr	
NO_X tpy:	1.62	tpy	
Total Cap Investment	$ 1,436,087		<--EPA Cost Estimate Spreadsheet
Annualized TCI:	$ 120,171		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 745,767		<--EPA Cost Estimate Spreadsheet
Total Annual Costs:	$ 865,938		
Emissions Reduction:	6.46	tpy	
Cost Effectiveness:	**$ 134,021.21**	**$/ton**	

Flue Gas Recirculation

NO_X control:	50%	Control Eff.	<-- Manufacturer estimate
NO_X ppm	45.00	ppm	
NO_X tpy:	4.04	tpy	
Total Cap Investment	$ 300,000		<--Client provided
Annualized TCI:	$ 25,104		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 14,000		<--Client Provided
Total Annual Costs:	$ 39,104		
Emissions Reduction:	2.42	tpy	
Cost Effectiveness:	**$ 16,138.92**	**$/ton**	

SNCR

NO_X control:	90%	Control Eff.	<-- Manufacturer estimate
NO_X ppm	9.00	ppm	
NO_X tpy:	0.81	tpy	
Total Cap Investment	$ 1,200,000		<--Client provided
Annualized TCI:	$ 100,415		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 200,000		<--Client Provided
Total Annual Costs:	$ 300,415		
Emissions Reduction:	1.62	tpy	
Cost Effectiveness:	**$ 185,981.00**	**$/ton**	

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	25	MMBtu/hr
What is the higher heating value (HHV) of the fuel?	1,000	Btu/scf
What is the estimated actual annual MWhs output?	219,500,000	scf/year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3400	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	73.59	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	14.72	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	700	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	16.67	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0361	$/kWh			* $0.0361/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	-	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	-	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1025	Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	25	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	219,500,000	scf/year	
Actual Annual fuel consumption (Mactual) =		219,500,000	scf/year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	1.47	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	6.45	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	417.6	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	0.2	/hour	
Residence Time	1/V_{space}	5.4119	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.13		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.0	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	2,260.11	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	0	ft^2

Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1,733	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	1	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	0.7	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	6,968	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	573	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	1,977	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	264	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	88,800	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	12.88	kW

Cost Estimate

Total Capital Investment (TCI)

1.13 ELEVF

TCI for Oil and Natural Gas Boilers

	New	Retrofit
For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW: $TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$	$0	$0
For Oil and Natural Gas-Fired Utility Boilers >500 MW: $TCI = 62,680 \times B_{MW} \times ELEVF \times RF$	$0	$0
For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour : $TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$	$0	$0
For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour : $TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$	$0	$1,289,882
For Oil-Fired Industrial Boilers >5,500 MMBtu/hour: $TCI = 5,700 \times Q_B \times ELEVF \times RF$	$0	$0
For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour: $TCI = 7,640 \times Q_B \times ELEVF \times RF$	$0	$0
	$0	$1,289,882

Total Capital Investment (TCI) =	$1,436,087	in 2018 dollars

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$0	in 2018 dollars
Reagent Preparation Cost (RPC) =	$0	in 2018 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2018 dollars
Balance of Plant Costs (BPC) =	$0	in 2018 dollars
Total Capital Investment (TCI) =	$0	in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW: $SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$	$0.00	$0.00
For Coal-Fired Industrial Boilers >250 MMBtu/hour: $SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$	0.00	0.00
	$0	$0

SCR Capital Costs (SCR_{cost}) =	$0 in 2018 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW: $RPC = 564,000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$	$0	$0
For Coal-Fired Industrial Boilers >250 MMBtu/hour: $RPC = 564,000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$	$0	$0
	$0	$0

Reagent Preparation Costs (RPC) =	$0 in 2018 dollars

Air Pre-Heater Costs (APHC)*				
For Coal-Fired Utility Boilers >25MW:				
	$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$		$0	$0
For Coal-Fired Industrial Boilers >250 MMBtu/hour:				
	$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$		$0	$0
Air Pre-Heater Costs (APH_{cost}) =		$0 in 2018 dollars	**$0**	**$0**

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)				
For Coal-Fired Utility Boilers >25MW:				
	$BPC = 529{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$		**$0**	**$0**
For Coal-Fired Industrial Boilers >250 MMBtu/hour:				
	$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42} ELEVF \times RF$		**$0**	**$0**
Balance of Plant Costs (BOP_{cost}) =		$0 in 2018 dollars	**$0**	**$0**

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$743,053 in 2018 dollars
Indirect Annual Costs (IDAC) =	$122,915 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$865,968 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$7,180 in 2018 dollars	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$0	#REF!
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$677,809 in 2018 dollars	
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$4,074 in 2018 dollars	
Annual Catalyst Replacement Cost =		$53,989 in 2018 dollars	
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$		
Direct Annual Cost =		$743,053 in 2018 dollars	

	1
Method 1	$53,989
	9,794

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,714 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$120,200 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$122,915 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$865,968	per year in 2018 dollars
NOx Removed =	6.45	tons/year
Cost Effectiveness =	$134,314	per ton of NOx removed in 2018 dollars

Targa Eunice Gas Processing Plant

Eunice Gas Plant

Boiler	Interest Rate:	5.50%		
Unit B-02	Period (yrs):	20		<-- EPA Guidance Default
Base Emissions				
NO_X ppm		90	ppm	<-- From client
NO_X lb/hr:		1.54	lb/hr	<-- From 2016 EI calculations
NO_X tpy:		6.73	tpy	<-- From 2016 EI calculations
SCR				
NO_X control:		80%	Control Eff.	<-- Assumed for SCR, AP-42 Section 1.4
NO_X lb/hr:		0.31	lb/hr	
NO_X tpy:		1.35	tpy	
Total Cap Investment	$	1,436,087		<--EPA Cost Estimate Spreadsheet
Annualized TCI:	$	120,171		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	632,661		<--EPA Cost Estimate Spreadsheet
Total Annual Costs:	$	752,832		
Emissions Reduction:		5.38	tpy	
Cost Effectiveness:	**$**	**139,853.11**	**$/ton**	
Flue Gas Recirculation				
NO_X control:		50%	Control Eff.	<-- Manufacturer estimate
NO_X ppm		45.00	ppm	
NO_X tpy:		3.36	tpy	
Total Cap Investment	$	300,000		<--Client provided
Annualized TCI:	$	25,104		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	14,000		<--Client provided
Total Annual Costs:	$	39,104		
Emissions Reduction:		2.02	tpy	
Cost Effectiveness:	**$**	**19,371.44**	**$/ton**	

SNCR

NO_X control:		50%	Control Eff.	<-- Manufacturer estimate
NO_X ppm		9.00	ppm	
NO_X tpy:		0.67	tpy	
Total Cap Investment	$	1,200,000		<--Client provided
Annualized TCI:	$	100,415		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	200,000		<--Client provided
Total Annual Costs:	$	300,415		
Emissions Reduction:		1.35	tpy	
Cost Effectiveness:	**$**	**223,231.80**	**$/ton**	

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	25	MMBtu/hr
What is the higher heating value (HHV) of the fuel?	1,000	Btu/scf
What is the estimated actual annual MWhs output?	219,500,000	scf/year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3400	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = _____ percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ● Method 2
- ○ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	61.31	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	12.26	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	700	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	16.67	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0361	$/kWh			* $0.0361/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	-	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	-	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1025	Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	25	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	219,500,000	scf/year	
Actual Annual fuel consumption (Mactual) =		219,500,000	scf/year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	1.23	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	5.38	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	417.6	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	0.2	/hour	
Residence Time	1/V_{space}	5.4119	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.13		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.0	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	2,260.11	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	0	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1,733	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	1	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	0.7	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	6,968	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	478	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	1,647	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	220	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	74,000	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	12.88	kW

Cost Estimate

Total Capital Investment (TCI)

1.13 ELEVF

TCI for Oil and Natural Gas Boilers

	New	Retrofit
For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW: $TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$	$0	$0
For Oil and Natural Gas-Fired Utility Boilers >500 MW: $TCI = 62,680 \times B_{MW} \times ELEVF \times RF$	$0	$0
For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour : $TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$	$0	$0
For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour : $TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$	$0	$1,289,882
For Oil-Fired Industrial Boilers >5,500 MMBtu/hour: $TCI = 5,700 \times Q_B \times ELEVF \times RF$	$0	$0
For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour: $TCI = 7,640 \times Q_B \times ELEVF \times RF$	$0	$0
	$0	$1,289,882

Total Capital Investment (TCI) =	$1,436,087	in 2018 dollars

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$0	in 2018 dollars
Reagent Preparation Cost (RPC) =	$0	in 2018 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2018 dollars
Balance of Plant Costs (BPC) =	$0	in 2018 dollars
Total Capital Investment (TCI) =	$0	in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW: $SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$	$0.00	$0.00
For Coal-Fired Industrial Boilers >250 MMBtu/hour: $SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$	0.00	0.00
	$0	$0

SCR Capital Costs (SCR_{cost}) =	$0 in 2018 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW: $RPC = 564,000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$	$0	$0
For Coal-Fired Industrial Boilers >250 MMBtu/hour: $RPC = 564,000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$	$0	$0

Reagent Preparation Costs (RPC) =	$0 in 2018 dollars	**$0**	**$0**

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

	$0	$0

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

	$0	$0

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2018 dollars	**$0**	**$0**

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$$

	$0	**$0**

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42} ELEVF \times RF$$

	$0	**$0**

Balance of Plant Costs (BOP_{cost}) =	$0 in 2018 dollars	**$0**	**$0**

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$629,947 in 2018 dollars
Indirect Annual Costs (IDAC) =	$122,915 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$752,862 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$7,180 in 2018 dollars	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$0	#REF!
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$564,703 in 2018 dollars	
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$4,074 in 2018 dollars	
Annual Catalyst Replacement Cost =		$53,989 in 2018 dollars	
			1
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$		Method 1 $53,989
Direct Annual Cost =		$629,947 in 2018 dollars	9,794

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,714 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$120,200 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$122,915 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$752,862	per year in 2018 dollars
NOx Removed =	5.38	tons/year
Cost Effectiveness =	$139,859	per ton of NOx removed in 2018 dollars

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:	5.50%	
Units: C-01	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1200	hp	<-- As permitted
2016 Operating Hours	8009	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	13.165	g/hp-hr	<-- From 7/22/15 performance test
NO_X lb/hr:	34.83	lb/hr	<-- Calculated
NO_X tpy:	139.47	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		69.6%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		4.00	g/hp-hr	<-- Based on assumptions from manufacture
NO_X lb/hr:		10.58	lb/hr	
NO_X tpy:		42.38	tpy	<--Calculated from 2016 hr/yr
Total Cap Investment	$	5,303,408		<--Vendor quote
Annualized TCI:	$	443,786		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	543,786		
Emissions Reduction:		97.09	tpy	
Cost Effectiveness:	**$**	**5,600.65**	**$/ton**	

Clean Burn Technologies				
NO_X guarantee:		62.0%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		5.00	g/hp-hr	<-- Based on assumptions from manufacture
NO_X lb/hr:		13.23	lb/hr	
NO_X tpy:		52.97	tpy	<--Calculated from 2016 hr/yr
Equipment, install labor and materials	$	1,101,346		<-- From Vendor
Auxiliary Cooling System	$	66,573		<-- From Vendor
Fuel System Modification	$	24,166.67		<-- Targa estimated
Custody Transfer Metering	$	19,166.67		<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00		<-- Targa estimated
Permitting Cost	$	3,750.00		<-- Targa estimated
Taxes, Contingency	$	737,625.39		<-- Targa estimated
Total Cap Investment	**$**	**4,952,628**		
Annualized TCI:	$	414,433		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	514,433		
Emissions Reduction:		86.50	tpy	
Cost Effectiveness:	**$**	**5,947.24**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:		5.50%	
Units: C-02	Period (yrs):		20	<-- EPA Guidance Default for SCR
Base Emissions				
Site Horsepower		1200	hp	<-- As permitted
2016 Operating Hours		4271	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)		9.226	g/hp-hr	<-- From 7/22/15 performance test
NO_X lb/hr:		24.41	lb/hr	<-- Calculated
NO_X tpy:		52.12	tpy	<-- Calculated
Clean Burn Technologies				
NO_X guarantee:		56.6%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		4.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:		10.58	lb/hr	
NO_X tpy:		22.60	tpy	<--Calculated from 2016 hr/yr
Total Cap Investment	$	5,303,408		<--Vendor quote
Annualized TCI:	$	443,786		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	543,786		
Emissions Reduction:		29.52	tpy	
Cost Effectiveness:	**$**	**18,418.34**	**$/ton**	
Clean Burn Technologies				
NO_X guarantee:		45.8%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		5.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:		13.23	lb/hr	
NO_X tpy:		28.25	tpy	<--Calculated from 2016 hr/yr
Equipment, install labor and materials	$	1,101,346		<-- From Vendor
Auxiliary Cooling System	$	66,573		<-- From Vendor
Fuel System Modification	$	24,166.67		<-- Targa estimated
Custody Transfer Metering	$	19,166.67		<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00		<-- Targa estimated
Permitting Cost	$	3,750.00		<-- Targa estimated
Taxes, Contingency	$	737,625.39		<-- Targa estimated
Total Cap Investment	**$**	**4,952,628**		
Annualized TCI:	$	414,433		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	514,433		
Emissions Reduction:		23.87	tpy	
Cost Effectiveness:	**$**	**21,547.22**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:		5.50%	
Units: C-03	Period (yrs):		20	<-- EPA Guidance Default for SCR
Base Emissions				
Site Horsepower		1200	hp	<-- As permitted
2016 Operating Hours		7275	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)		14.41	g/hp-hr	<-- From client
NO_X lb/hr:		38.11	lb/hr	<-- Calculated
NO_X tpy:		138.64	tpy	<-- Calculated
Clean Burn Technologies				
NO_X guarantee:		72.2%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		4.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:		10.58	lb/hr	
NO_X tpy:		38.49	tpy	<--Calculated from 2016 hr/yr
Total Cap Investment	$	5,303,408		<--Vendor quote
Annualized TCI:	$	443,786		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	543,786		
Emissions Reduction:		100.15	tpy	
Cost Effectiveness:	**$**	**5,429.89**	**$/ton**	
Clean Burn Technologies				
NO_X guarantee:		65.3%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		5.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:		13.23	lb/hr	
NO_X tpy:		48.12	tpy	<--Calculated from 2016 hr/yr
Equipment, install labor and materials	$	1,101,346		<-- From Vendor
Auxiliary Cooling System	$	66,573		<-- From Vendor
Fuel System Modification	$	24,166.67		<-- Targa estimated
Custody Transfer Metering	$	19,166.67		<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00		<-- Targa estimated
Permitting Cost	$	3,750.00		<-- Targa estimated
Taxes, Contingency	$	737,625.39		<-- Targa estimated
Total Cap Investment	**$**	**4,952,628**		
Annualized TCI:	$	414,433		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	514,433		
Emissions Reduction:		90.52	tpy	
Cost Effectiveness:	**$**	**5,682.85**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:	5.50%	
Units: C-04	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1200	hp	<-- As permitted
2016 Operating Hours	5996	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	11.742	g/hp-hr	<-- From 7/23/15 performance test
NO_X lb/hr:	31.06	lb/hr	<-- Calculated
NO_X tpy:	93.13	tpy	<-- Calculated

Clean Burn Technologies			
NO_X guarantee:	65.9%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	4.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:	10.58	lb/hr	
NO_X tpy:	31.72	tpy	<--Calculated from 2016 hr/yr

Total Cap Investment	$	5,303,408	<--Vendor quote
Annualized TCI:	$	443,786	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000	<--Client provided
Total Annual Costs:	$	543,786	
Emissions Reduction:		61.40 tpy	
Cost Effectiveness:	**$**	**8,855.94**	**$/ton**

Clean Burn Technologies			
NO_X guarantee:	57.4%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	5.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:	13.23	lb/hr	
NO_X tpy:	39.66	tpy	<--Calculated from 2016 hr/yr

Equipment, install labor and materials	$	1,101,346	<-- From Vendor
Auxiliary Cooling System	$	66,573	<-- From Vendor
Fuel System Modification	$	24,166.67	<-- Targa estimated
Custody Transfer Metering	$	19,166.67	<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00	<-- Targa estimated
Permitting Cost	$	3,750.00	<-- Targa estimated
Taxes, Contingency	$	737,625.39	<-- Targa estimated
Total Cap Investment	**$**	**4,952,628**	
Annualized TCI:	$	414,433	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000	<--Client provided
Total Annual Costs:	$	514,433	
Emissions Reduction:		53.47 tpy	
Cost Effectiveness:	**$**	**9,620.55**	**$/ton**

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:	5.50%	
Units: C-05	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1200	hp	<-- As permitted
2016 Operating Hours	7684	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	9.285	g/hp-hr	<-- From 7/23/15 performance test
NO_X lb/hr:	24.56	lb/hr	<-- Calculated
NO_X tpy:	94.37	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		56.9%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		4.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:		10.58	lb/hr	
NO_X tpy:		40.66	tpy	<--Calculated from 2016 hr/yr
Total Cap Investment	$	5,303,408		<--Vendor quote
Annualized TCI:	$	443,786		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	543,786		
Emissions Reduction:		53.72	tpy	
Cost Effectiveness:	**$**	**10,123.18**	**$/ton**	

Clean Burn Technologies				
NO_X guarantee:		46.1%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		5.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:		13.23	lb/hr	
NO_X tpy:		50.82	tpy	<--Calculated from 2016 hr/yr
Equipment, install labor and materials	$	1,101,346		<-- From Vendor
Auxiliary Cooling System	$	66,573		<-- From Vendor
Fuel System Modification	$	24,166.67		<-- Targa estimated
Custody Transfer Metering	$	19,166.67		<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00		<-- Targa estimated
Permitting Cost	$	3,750.00		<-- Targa estimated
Taxes, Contingency	$	737,625.39		<-- Targa estimated
Total Cap Investment	**$**	**4,952,628**		
Annualized TCI:	$	414,433		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	514,433		
Emissions Reduction:		43.55	tpy	
Cost Effectiveness:	**$**	**11,811.69**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:	5.50%	
Units: C-06	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1200	hp	<-- As permitted
2016 Operating Hours	8123	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	13.261	g/hp-hr	<-- From 7/23/15 performance test
NO_X lb/hr:	35.08	lb/hr	<-- Calculated
NO_X tpy:	142.49	tpy	<-- Calculated

Clean Burn Technologies			
NO_X guarantee:	69.8%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	4.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:	10.58	lb/hr	
NO_X tpy:	42.98	tpy	<--Calculated from 2016 hr/yr
Total Cap Investment	$ 5,303,408		<--Vendor quote
Annualized TCI:	$ 443,786		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 100,000		<--Client provided
Total Annual Costs:	$ 543,786		
Emissions Reduction:	99.51	tpy	
Cost Effectiveness:	**$ 5,464.81**	**$/ton**	

Clean Burn Technologies			
NO_X guarantee:	62.3%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	5.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:	13.23	lb/hr	
NO_X tpy:	53.72	tpy	<--Calculated from 2016 hr/yr
Equipment, install labor and materials	$ 1,101,346		<-- From Vendor
Auxiliary Cooling System	$ 66,573		<-- From Vendor
Fuel System Modification	$ 24,166.67		<-- Targa estimated
Custody Transfer Metering	$ 19,166.67		<-- Targa estimated
Electrical Power to MCC	$ 3,000,000.00		<-- Targa estimated
Permitting Cost	$ 3,750.00		<-- Targa estimated
Taxes, Contingency	$ 737,625.39		<-- Targa estimated
Total Cap Investment	**$ 4,952,628**		
Annualized TCI:	$ 414,433		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 100,000		<--Client provided
Total Annual Costs:	$ 514,433		
Emissions Reduction:	88.76	tpy	
Cost Effectiveness:	**$ 5,795.64**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:	5.50%	
Units: C-07	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1200	hp	<-- As permitted
2016 Operating Hours	6476	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	13.787	g/hp-hr	<-- From 7/27/15 performance test
NO_X lb/hr:	36.47	lb/hr	<-- Calculated
NO_X tpy:	118.10	tpy	<-- Calculated

Clean Burn Technologies			
NO_X guarantee:	71.0%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	4.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:	10.58	lb/hr	
NO_X tpy:	34.26	tpy	<--Calculated from 2016 hr/yr
Total Cap Investment	$ 5,303,408		<--Vendor quote
Annualized TCI:	$ 443,786		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 100,000		<--Client provided
Total Annual Costs:	$ 543,786		
Emissions Reduction:	83.84	tpy	
Cost Effectiveness:	**$ 6,486.24**	**$/ton**	

Clean Burn Technologies			
NO_X guarantee:	63.7%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	5.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:	13.23	lb/hr	
NO_X tpy:	42.83	tpy	<--Calculated from 2016 hr/yr
Equipment, install labor and materials	$ 1,101,346		<-- From Vendor
Auxiliary Cooling System	$ 66,573		<-- From Vendor
Fuel System Modification	$ 24,166.67		<-- Targa estimated
Custody Transfer Metering	$ 19,166.67		<-- Targa estimated
Electrical Power to MCC	$ 3,000,000.00		<-- Targa estimated
Permitting Cost	$ 3,750.00		<-- Targa estimated
Taxes, Contingency	$ 737,625.39		<-- Targa estimated
Total Cap Investment	**$ 4,952,628**		
Annualized TCI:	$ 414,433		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 100,000		<--Client provided
Total Annual Costs:	$ 514,433		
Emissions Reduction:	75.27	tpy	
Cost Effectiveness:	**$ 6,834.44**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:		5.50%	
Units: C-08	Period (yrs):		20	<-- EPA Guidance Default for SCR
Base Emissions				
Site Horsepower		1200	hp	<-- As permitted
2016 Operating Hours		#REF!	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)		19.583	g/hp-hr	<-- From 7/27/15 performance test
NO_X lb/hr:		51.81	lb/hr	<-- Calculated
NO_X tpy:		#REF!	tpy	<-- Calculated
Clean Burn Technologies				
NO_X guarantee:		89.8%	Control Eff.	<-- Calculated ($NO_{X(in)}$ - $NO_{X(out)}$)/$NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		5.29	lb/hr	
NO_X tpy:		#REF!	tpy	
Total Cap Investment	$	950,000		<--Manufacturer specification
Annualized TCI:	$	79,495		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	179,495		
Emissions Reduction:		#REF!	tpy	
Cost Effectiveness:		**#REF!**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark BA-6	Interest Rate:	5.50%	
Units: C-09	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1200	hp	<-- As permitted
2016 Operating Hours	500	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	17.249	g/hp-hr	<-- From 7/28/15 performance test
NO_X lb/hr:	45.63	lb/hr	<-- Calculated
NO_X tpy:	11.41	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		76.8%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		4.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:		10.58	lb/hr	
NO_X tpy:		2.65	tpy	<--Calculated from 2016 hr/yr
Total Cap Investment	$	5,303,408		<--Vendor quote
Annualized TCI:	$	443,786		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	543,786		
Emissions Reduction:		8.76	tpy	
Cost Effectiveness:	**$**	**62,057.80**	**$/ton**	

Clean Burn Technologies				
NO_X guarantee:		71.0%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		5.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:		13.23	lb/hr	
NO_X tpy:		3.31	tpy	<--Calculated from 2016 hr/yr
Equipment, install labor and materials	$	1,101,346		<-- From Vendor
Auxiliary Cooling System	$	66,573		<-- From Vendor
Fuel System Modification	$	24,166.67		<-- Targa estimated
Custody Transfer Metering	$	19,166.67		<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00		<-- Targa estimated
Permitting Cost	$	3,750.00		<-- Targa estimated
Taxes, Contingency	$	737,625.39		<-- Targa estimated
Total Cap Investment	**$**	**4,952,628**		
Annualized TCI:	$	414,433		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	514,433		
Emissions Reduction:		8.10	tpy	
Cost Effectiveness:	**$**	**63,500.86**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark HBA-8	Interest Rate:	5.50%	
Units: C-10	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1600	hp	<-- As permitted
2016 Operating Hours	500	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	11.401	g/hp-hr	<-- From 7/28/15 performance test
NO_X lb/hr:	40.22	lb/hr	<-- Calculated
NO_X tpy:	10.05	tpy	<-- Calculated

Clean Burn Technologies			
NO_X guarantee:	64.9%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	4.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:	14.11	lb/hr	
NO_X tpy:	3.53	tpy	<--Calculated from 2016 hr/yr

Total Cap Investment	**$**	**5,370,303**	
Annualized TCI:	$	449,383	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000	<--Client provided
Total Annual Costs:	$	549,383	
Emissions Reduction:		6.53 tpy	
Cost Effectiveness:	**$**	**84,177.91**	**$/ton**

Clean Burn Technologies			
NO_X guarantee:	56.1%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	5.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:	17.64	lb/hr	
NO_X tpy:	4.41	tpy	<--Calculated from 2016 hr/yr

Equipment, install labor and materials	$	1,158,278	<-- From Vendor
Auxiliary Cooling System	$	66,573	<-- From Vendor
Fuel System Modification	$	24,166.67	<-- Targa estimated
Custody Transfer Metering	$	19,166.67	<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00	<-- Targa estimated
Permitting Cost	$	3,750.00	<-- Targa estimated
Taxes, Contingency	$	747,588.49	<-- Targa estimated
Total Cap Investment	**$**	**5,019,523**	
Annualized TCI:	$	420,030	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000	<--Client provided
Total Annual Costs:	$	520,030	
Emissions Reduction:		5.64 tpy	
Cost Effectiveness:	**$**	**92,128.47**	**$/ton**

Eunice Gas Plant

2SLB Engine - Clark HBA-8	Interest Rate:	5.50%	
Units: C-11	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1600	hp	<-- As permitted
2016 Operating Hours	500	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	16.265	g/hp-hr	<-- From 7/28/15 performance test
NO_X lb/hr:	57.37	lb/hr	<-- Calculated
NO_X tpy:	14.34	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		75.4%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		4.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:		14.11	lb/hr	
NO_X tpy:		3.53	tpy	<--Calculated from 2016 hr/yr
Total Cap Investment	$	5,370,303		<--Vendor quote
Annualized TCI:	$	449,383		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	549,383		
Emissions Reduction:		10.82	tpy	
Cost Effectiveness:	**$**	**50,795.00**	**$/ton**	

Clean Burn Technologies				
NO_X guarantee:		69.3%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		5.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:		17.64	lb/hr	
NO_X tpy:		4.41	tpy	<--Calculated from 2016 hr/yr
Equipment, install labor and materials	$	1,158,278		<-- From Vendor
Auxiliary Cooling System	$	66,573		<-- From Vendor
Fuel System Modification	$	24,166.67		<-- Targa estimated
Custody Transfer Metering	$	19,166.67		<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00		<-- Targa estimated
Permitting Cost	$	3,750.00		<-- Targa estimated
Taxes, Contingency	$	747,588.49		<-- Targa estimated
Total Cap Investment	**$**	**5,019,523**		
Annualized TCI:	$	420,030		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	520,030		
Emissions Reduction:		9.93	tpy	
Cost Effectiveness:	**$**	**52,349.26**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark HBA-8	Interest Rate:	5.50%	
Units: C-12	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	1600	hp	<-- As permitted
2016 Operating Hours	500	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	9.838	g/hp-hr	<-- From 7/29/15 performance test
NO_X lb/hr:	34.70	lb/hr	<-- Calculated
NO_X tpy:	8.68	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		59.3%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		4.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:		14.11	lb/hr	
NO_X tpy:		3.53	tpy	<--Calculated from 2016 hr/yr
Total Cap Investment	$	5,370,303		<--Vendor quote
Annualized TCI:	$	449,383		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	549,383		
Emissions Reduction:		5.15	tpy	
Cost Effectiveness:	**$**	**106,714.75**	**$/ton**	

Clean Burn Technologies				
NO_X guarantee:		49.2%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		5.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:		17.64	lb/hr	
NO_X tpy:		4.41	tpy	<--Calculated from 2016 hr/yr
Equipment, install labor and materials	$	1,158,278		<-- From Vendor
Auxiliary Cooling System	$	66,573		<-- From Vendor
Fuel System Modification	$	24,166.67		<-- Targa estimated
Custody Transfer Metering	$	19,166.67		<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00		<-- Targa estimated
Permitting Cost	$	3,750.00		<-- Targa estimated
Taxes, Contingency	$	747,588.49		<-- Targa estimated
Total Cap Investment	**$**	**5,019,523**		
Annualized TCI:	$	420,030		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	520,030		
Emissions Reduction:		4.27	tpy	
Cost Effectiveness:	**$**	**121,892.18**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark HBA-T8	Interest Rate:	5.50%	
Units: C-13	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	2050	hp	<-- As permitted
2016 Operating Hours	7560	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	13.654	g/hp-hr	<-- From 7/29/15 performance test
NO_X lb/hr:	61.71	lb/hr	<-- Calculated
NO_X tpy:	233.26	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		70.7%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		4.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:		18.08	lb/hr	
NO_X tpy:		68.33	tpy	<--Calculated from 2016 hr/yr
Total Cap Investment	$	5,370,303		<--Vendor quote
Annualized TCI:	$	449,383		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	549,383		
Emissions Reduction:		164.92	tpy	
Cost Effectiveness:	**$**	**3,331.16**	**$/ton**	

Clean Burn Technologies				
NO_X guarantee:		63.4%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		5.00	g/hp-hr	<-- Based on assumptions from manufacturer
NO_X lb/hr:		22.60	lb/hr	
NO_X tpy:		85.42	tpy	<--Calculated from 2016 hr/yr
Equipment, install labor and materials	$	1,158,278		<-- From Vendor
Auxiliary Cooling System	$	66,573		<-- From Vendor
Fuel System Modification	$	24,166.67		<-- Targa estimated
Custody Transfer Metering	$	19,166.67		<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00		<-- Targa estimated
Permitting Cost	$	3,750.00		<-- Targa estimated
Taxes, Contingency	$	747,588.49		<-- Targa estimated
Total Cap Investment	**$**	**5,019,523**		
Annualized TCI:	$	420,030		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	520,030		
Emissions Reduction:		147.84	tpy	
Cost Effectiveness:	**$**	**3,517.54**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark RA-8	Interest Rate:	5.50%	
Units: C-01	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	800	hp	<-- As permitted
2016 Operating Hours	2357	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	11.9	g/hp-hr	<-- From 4/21/15 performance test
NO_X lb/hr:	20.99	lb/hr	<-- Calculated
NO_X tpy:	24.73	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		66.4%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		4.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:		7.05	lb/hr	
NO_X tpy:		8.31	tpy	<--Calculated based on 2016 hr/yr
Total Cap Investment	$	5,765,849		<--Vendor Quote
Annualized TCI:	$	482,482		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	582,482		
Emissions Reduction:		16.42	tpy	
Cost Effectiveness:	**$**	**35,473.92**	**$/ton**	

Clean Burn Technologies				
NO_X guarantee:		58.0%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		5.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:		8.82	lb/hr	
NO_X tpy:		10.39	tpy	<--Calculated based on 2016 hr/yr
Equipment, install labor and materials	$	956,153		<-- From Vendor
Auxiliary Cooling System	$	558,250		<-- From Vendor
Fuel System Modification	$	48,333.33		<-- Targa estimated
Custody Transfer Metering	$	38,333.33		<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00		<-- Targa estimated
Permitting Cost	$	7,500.00		<-- Targa estimated
Taxes, Contingency	$	806,499.69		<-- Targa estimated
Total Cap Investment	**$**	**5,415,069**		
Annualized TCI:	$	453,129		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	553,129		
Emissions Reduction:		14.34	tpy	
Cost Effectiveness:	**$**	**38,568.35**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark RA-8	Interest Rate:	5.50%	
Units: C-02	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	800	hp	<-- As permitted
2016 Operating Hours	4069	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	9.8	g/hp-hr	<-- From 4/21/15 performance test
NO_X lb/hr:	17.28	lb/hr	<-- Calculated
NO_X tpy:	35.16	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		59.2%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		4.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		7.05	lb/hr	
NO_X tpy:		14.35	tpy	
Total Cap Investment	$	5,765,849		<--Manufacturer specification
Annualized TCI:	$	482,482		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	582,482		
Emissions Reduction:		20.81	tpy	
Cost Effectiveness:	**$**	**27,988.54**	**$/ton**	

Clean Burn Technologies				
NO_X guarantee:		49.0%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		5.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		8.82	lb/hr	
NO_X tpy:		17.94	tpy	
Equipment, install labor and materials	$	956,153		<-- From Vendor
Auxiliary Cooling System	$	558,250		<-- From Vendor
Fuel System Modification	$	48,333.33		<-- Targa estimated
Custody Transfer Metering	$	38,333.33		<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00		<-- Targa estimated
Permitting Cost	$	7,500.00		<-- Targa estimated
Taxes, Contingency	$	806,499.69		<-- Targa estimated
Total Cap Investment	**$**	**5,415,069**		
Annualized TCI:	$	453,129		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	553,129		
Emissions Reduction:		17.22	tpy	
Cost Effectiveness:	**$**	**32,115.22**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark RA-6	Interest Rate:	5.50%	
Units: C-04	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	600	hp	<-- As permitted
2016 Operating Hours	990	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	9.9	g/hp-hr	<-- From 4/23/15 performance test
NO_X lb/hr:	13.10	lb/hr	<-- Calculated
NO_X tpy:	6.48	tpy	<-- Calculated

Clean Burn Technologies

NO_X guarantee:	59.6%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	4.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:	5.29	lb/hr	
NO_X tpy:	2.62	tpy	<--Calculated based on 2016 hr/yr
Total Cap Investment	$ 5,120,345		<--Vendor Quote
Annualized TCI:	$ 428,467		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 100,000		<--Client provided
Total Annual Costs:	$ 528,467		
Emissions Reduction:	3.86	tpy	
Cost Effectiveness:	**$ 136,798.87**	**$/ton**	

Clean Burn Technologies

NO_X guarantee:	49.5%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	5.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:	6.61	lb/hr	
NO_X tpy:	3.27	tpy	<--Calculated based on 2016 hr/yr
Equipment, install labor and materials	$ 914,621		<-- From Vendor
Auxiliary Cooling System	$ 79,750		<-- From Vendor
Fuel System Modification	$ 33,333		<-- Targa estimated
Custody Transfer Metering	$ 24,000		<-- Targa estimated
Electrical Power to MCC	$ 3,000,000		<-- Targa estimated
Permitting Cost	$ 7,500		<-- Targa estimated
Taxes, Contingency	$ 710,361		<-- Targa estimated
Total Cap Investment	$ 4,769,565		
Annualized TCI:	$ 399,114		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 100,000		<--Client provided
Total Annual Costs:	$ 499,114		
Emissions Reduction:	3.21	tpy	
Cost Effectiveness:	**$ 155,568.00**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark RA-6	Interest Rate:	5.50%	
Units: C-06	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	600	hp	<-- As permitted
2016 Operating Hours	2035	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	11.4	g/hp-hr	<-- From 4/21/15 performance test
NO_X lb/hr:	15.08	lb/hr	<-- Calculated
NO_X tpy:	15.34	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		64.9%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		4.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:		5.29	lb/hr	
NO_X tpy:		5.38	tpy	<--Calculated based on 2016 hr/yr
Total Cap Investment	$	5,120,345		<--Vendor Quote
Annualized TCI:	$	428,467		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	528,467		
Emissions Reduction:		9.96	tpy	
Cost Effectiveness:	**$**	**53,060.77**	**$/ton**	

Clean Burn Technologies				
NO_X guarantee:		56.1%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		5.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:		6.61	lb/hr	
NO_X tpy:		6.73	tpy	<--Calculated based on 2016 hr/yr
Equipment, install labor and materials	$	914,621		<-- From Vendor
Auxiliary Cooling System	$	79,750		<-- From Vendor
Fuel System Modification	$	33,333		<-- Targa estimated
Custody Transfer Metering	$	24,000		<-- Targa estimated
Electrical Power to MCC	$	3,000,000		<-- Targa estimated
Permitting Cost	$	7,500		<-- Targa estimated
Taxes, Contingency	$	710,361		<-- Targa estimated
Total Cap Investment	$	4,769,565		
Annualized TCI:	$	399,114		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--EPA Cost Estimate Spreadsheet
Total Annual Costs:	$	499,114		
Emissions Reduction:		8.61	tpy	
Cost Effectiveness:	**$**	**57,943.83**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark RA-6	Interest Rate:	5.50%	
Units: C-05	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	600	hp	<-- As permitted
2016 Operating Hours	3938	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	8.4	g/hp-hr	<-- From 4/22/15 performance test
NO_X lb/hr:	11.11	lb/hr	<-- Calculated
NO_X tpy:	21.88	tpy	<-- Calculated

Clean Burn Technologies

NO_X guarantee:	52.4%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	4.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:	5.29	lb/hr	
NO_X tpy:	10.42	tpy	<--Calculated based on 2016 hr/yr
Total Cap Investment	$ 5,120,345		<--Vendor Quote
Annualized TCI:	$ 428,467		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 100,000		<--Client provided
Total Annual Costs:	$ 528,467		
Emissions Reduction:	11.46	tpy	
Cost Effectiveness:	**$ 46,114.90**	**$/ton**	

Clean Burn Technologies

NO_X guarantee:	40.5%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	5.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:	6.61	lb/hr	
NO_X tpy:	13.02	tpy	<--Calculated based on 2016 hr/yr
Equipment, install labor and materials	$ 914,621		<-- From Vendor
Auxiliary Cooling System	$ 79,750		<-- From Vendor
Fuel System Modification	$ 33,333		<-- Targa estimated
Custody Transfer Metering	$ 24,000		<-- Targa estimated
Electrical Power to MCC	$ 3,000,000		<-- Targa estimated
Permitting Cost	$ 7,500		<-- Targa estimated
Taxes, Contingency	$ 710,361		<-- Targa estimated
Total Cap Investment	$ 4,769,565		
Annualized TCI:	$ 399,114		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 100,000		<--Client provided
Total Annual Costs:	$ 499,114		
Emissions Reduction:	8.86	tpy	
Cost Effectiveness:	**$ 56,363.37**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark HRA-8	Interest Rate:	5.50%	
Units: C-24	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	880	hp	<-- As permitted
2016 Operating Hours	6610	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	18.2	g/hp-hr	<-- From 4/22/15 performance test
NO_X lb/hr:	35.31	lb/hr	<-- Calculated
NO_X tpy:	116.70	tpy	<-- Calculated

Clean Burn Technologies

NO_X guarantee:	78.0%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	4.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:	7.76	lb/hr	
NO_X tpy:	25.65	tpy	<--Calculated based on 2016 hr/yr
Total Cap Investment	$ 5,765,849		<--Vendor Quote
Annualized TCI:	$ 482,482		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 100,000		<--Client provided
Total Annual Costs:	$ 582,482		
Emissions Reduction:	91.05	tpy	
Cost Effectiveness:	**$ 6,397.55**	**$/ton**	

Clean Burn Technologies

NO_X guarantee:	72.5%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	5.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:	9.70	lb/hr	
NO_X tpy:	32.06	tpy	<--Calculated based on 2016 hr/yr

Equipment, install labor and materials	$ 956,153	<-- From Vendor
Auxiliary Cooling System	$ 558,250	<-- From Vendor
Fuel System Modification	$ 48,333.33	<-- Targa estimated
Custody Transfer Metering	$ 38,333.33	<-- Targa estimated
Electrical Power to MCC	$ 3,000,000.00	<-- Targa estimated
Permitting Cost	$ 7,500.00	<-- Targa estimated
Taxes, Contingency	$ 806,499.69	<-- Targa estimated
Total Cap Investment	**$ 5,415,069**	
Annualized TCI:	$ 453,129	<-- Based on interest rate, year and TCI
Annual O&M Costs:	**$ 100,000**	<--Client provided
Total Annual Costs:	$ 553,129	
Emissions Reduction:	84.64 tpy	
Cost Effectiveness:	**$ 6,535.39**	**$/ton**

Monument Gas Plant

2SLB Engine - Cooper Bessemer GMVA-8	Interest Rate:		5.50%	
Units: C-28	Period (yrs):		20	<-- EPA Guidance Default for SCR
Base Emissions				
Site Horsepower		1100	hp	<-- As permitted
2016 Operating Hours		573	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)		6.3	g/hp-hr	<-- From 4/23/15 performance test
NO_X lb/hr:		15.28	lb/hr	<-- Calculated
NO_X tpy:		4.38	tpy	<-- Calculated
Clean Burn Technologies				
NO_X guarantee:		68.3%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		4.85	lb/hr	
NO_X tpy:		1.39	tpy	
Total Cap Investment	$	900,000		<--Manufacturer specification + Engineering of equip/in
Annualized TCI:	$	75,311		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	175,311		
Emissions Reduction:		2.99	tpy	
Cost Effectiveness:	**$**	**58,680.99**	**$/ton**	
Clean Burn Technologies				
NO_X guarantee:		36.5%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		4.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		9.70	lb/hr	
NO_X tpy:		2.78	tpy	
Total Cap Investment	$	805,000		<--Manufacturer specification + Engineering of equip/in
Annualized TCI:	$	67,362		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<-- From Vendor
Total Annual Costs:	$	167,362		
Emissions Reduction:		1.60	tpy	
Cost Effectiveness:	**$**	**104,733.21**	**$/ton**	

Saunders Revised Cost Analyses Omitted for Brevity

CBI Attachment Omitted

From: Roberts, Melanie
To: Hardison, Cember, NMENV
Cc: Jane Romero-Kotovsky; Klein, Cindy S.
Subject: [EXT] RE: [EXTERNAL] question about Eunice four factor calculations
Date: Thursday, March 12, 2020 2:44:35 PM
Attachments: Eunice_Cost Analysis v0.6 2020-0311 Final.xlsx
Monument_CostAnalysis v0.5 2020-0311_Final.xlsx

Targa has reviewed and has the following clarification on the report. Please let me know if you have any further questions.

> *In the original 4FA submitted to the NMED on 10/31/2019, Targa was only able to acquire vendor information on the Cooper Bessemer 2SLB units located at their facilities. Targa used the estimates from the Cooper engines for the Clark 2SLB units located at Eunice and Monument emissions, as this was the only information that Targa was able to obtain by the November 1, 2019 deadline set by the NMED.*
>
> *When the NMED requested additional information including vendor specific information in the December 23, 2019 letter to Targa, Targa was able receive a quote on the Clark 2SLB engines. The lowest guarantee provided to Targa for the Clark 2SLB engine located at the Targa sites was 2 g/hp-hr. There was a calculation error in the spreadsheets showing 4 g/hp-hr for the Clark engines that should have been 2 g/hp-hr. The Cooper Bessemer engines should remain the same. Please see attached revised calculation sheets with the calculation correction.*

From: Hardison, Cember, NMENV <Cember.Hardison@state.nm.us>
Sent: Thursday, March 5, 2020 4:54 PM
To: Roberts, Melanie <MRoberts@targaresources.com>
Cc: Klein, Cindy S. <CynthiaKlein@targaresources.com>; Woodell, Rebecca F. <RebeccaWoodell@targaresources.com>
Subject: [EXTERNAL] question about Eunice four factor calculations

Hello Melanie and Rebecca,
I highlighted the parts of Targa's 2-17 submittal that we had questions about.
Page 7 of the pdf mentions that the vendor quote provided was for 5 and 2 g/hp-hr. The vendor quote in the confidential information reflects 2 and 5 g/hp-hr and the costs for those two emission factors correlate with what is used in the calculations.
Page 83 has the Eunice and Monument engine calculations. See the highlighted 4 g/hp-hr in the calculations. It appears that 2 g/hp-hr should have been used, rather than 4.
Compare the Eunice and Monument engine calculations to the Saunders engine calculations starting on page 114. If an engine already met 4 g/hp-hr, then only the 2 g/hp-hr calculation was included.

Please let us know if the 4 g/hp-hr used for Eunice and Monument gas plants should be changed to 2 g/hp-hr.
Thank you for your help.

Cember Hardison
505 476 4346
If guidance or a determination is included in this email, it is intended to serve as general guidance and is in no way a formal statement of Department policy. New information or changes to regulations may result in a different determination or guidance.

Eunice Gas Plant

2SLB Engine - Clark HBA-8	Interest Rate:		5.50%	
Units: C-11	Period (yrs):		20	<-- EPA Guidance Default for SCR
Base Emissions				
Site Horsepower		1600	hp	<-- As permitted
2016 Operating Hours		500	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)		16.265	g/hp-hr	<-- From 7/28/15 performance test
NO_X lb/hr:		57.37	lb/hr	<-- Calculated
NO_X tpy:		14.34	tpy	<-- Calculated
Clean Burn Technologies				
NO_X guarantee:		87.7%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Based on assumptions from manufacture
NO_X lb/hr:		7.05	lb/hr	
NO_X tpy:		1.76	tpy	<--Calculated from 2016 hr/yr
Total Cap Investment	$	5,370,303		<--Vendor quote
Annualized TCI:	$	449,383		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	549,383		
Emissions Reduction:		12.58	tpy	
Cost Effectiveness:	**$**	**43,673.38**	**$/ton**	
Clean Burn Technologies				
NO_X guarantee:		69.3%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		5.00	g/hp-hr	<-- Based on assumptions from manufacture
NO_X lb/hr:		17.64	lb/hr	
NO_X tpy:		4.41	tpy	<--Calculated from 2016 hr/yr
Equipment, install labor and materials	$	1,158,278		<-- From Vendor
Auxiliary Cooling System	$	66,573		<-- From Vendor
Fuel System Modification	$	24,166.67		<-- Targa estimated
Custody Transfer Metering	$	19,166.67		<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00		<-- Targa estimated
Permitting Cost	$	3,750.00		<-- Targa estimated
Taxes, Contingency	$	747,588.49		<-- Targa estimated
Total Cap Investment	**$**	**5,019,523**		
Annualized TCI:	$	420,030		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	520,030		
Emissions Reduction:		9.93	tpy	
Cost Effectiveness:	**$**	**52,349.26**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark HBA-8	Interest Rate:		5.50%	
Units: C-12	Period (yrs):		20	<-- EPA Guidance Default for SCR
Base Emissions				
Site Horsepower		1600	hp	<-- As permitted
2016 Operating Hours		500	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)		9.838	g/hp-hr	<-- From 7/29/15 performance test
NO_X lb/hr:		34.70	lb/hr	<-- Calculated
NO_X tpy:		8.68	tpy	<-- Calculated

Clean Burn Technologies

NO_X guarantee:		79.7%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Based on assumptions from manufacture
NO_X lb/hr:		7.05	lb/hr	
NO_X tpy:		1.76	tpy	<--Calculated from 2016 hr/yr
Total Cap Investment	$	5,370,303		<--Vendor quote
Annualized TCI:	$	449,383		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	549,383		
Emissions Reduction:		6.91	tpy	
Cost Effectiveness:	**$**	**79,484.65**	**$/ton**	

Clean Burn Technologies

NO_X guarantee:		49.2%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		5.00	g/hp-hr	<-- Based on assumptions from manufacture
NO_X lb/hr:		17.64	lb/hr	
NO_X tpy:		4.41	tpy	<--Calculated from 2016 hr/yr
Equipment, install labor and materials	$	1,158,278		<-- From Vendor
Auxiliary Cooling System	$	66,573		<-- From Vendor
Fuel System Modification	$	24,166.67		<-- Targa estimated
Custody Transfer Metering	$	19,166.67		<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00		<-- Targa estimated
Permitting Cost	$	3,750.00		<-- Targa estimated
Taxes, Contingency	$	747,588.49		<-- Targa estimated
Total Cap Investment	**$**	**5,019,523**		
Annualized TCI:	$	420,030		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	520,030		
Emissions Reduction:		4.27	tpy	
Cost Effectiveness:	**$**	**121,892.18**	**$/ton**	

Eunice Gas Plant

2SLB Engine - Clark HBA-T8	Interest Rate:		5.50%	
Units: C-13	Period (yrs):		20	<-- EPA Guidance Default for SCR
Base Emissions				
Site Horsepower		2050	hp	<-- As permitted
2016 Operating Hours		7560	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)		13.654	g/hp-hr	<-- From 7/29/15 performance test
NO_X lb/hr:		61.71	lb/hr	<-- Calculated
NO_X tpy:		233.26	tpy	<-- Calculated
Clean Burn Technologies				
NO_X guarantee:		85.4%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Based on assumptions from manufacture
NO_X lb/hr:		9.04	lb/hr	
NO_X tpy:		34.17	tpy	<--Calculated from 2016 hr/yr
Total Cap Investment	$	5,370,303		<--Vendor quote
Annualized TCI:	$	449,383		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	549,383		
Emissions Reduction:		199.09	tpy	
Cost Effectiveness:	**$**	**2,759.48**	**$/ton**	

Clean Burn Technologies				
NO_X guarantee:		63.4%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		5.00	g/hp-hr	<-- Based on assumptions from manufacture
NO_X lb/hr:		22.60	lb/hr	
NO_X tpy:		85.42	tpy	<--Calculated from 2016 hr/yr
Equipment, install labor and materials	$	1,158,278		<-- From Vendor
Auxiliary Cooling System	$	66,573		<-- From Vendor
Fuel System Modification	$	24,166.67		<-- Targa estimated
Custody Transfer Metering	$	19,166.67		<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00		<-- Targa estimated
Permitting Cost	$	3,750.00		<-- Targa estimated
Taxes, Contingency	$	747,588.49		<-- Targa estimated
Total Cap Investment	**$**	**5,019,523**		
Annualized TCI:	$	420,030		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	520,030		
Emissions Reduction:		147.84	tpy	
Cost Effectiveness:	**$**	**3,517.54**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark RA-8	Interest Rate:	5.50%	
Units: C-01	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	800	hp	<-- As permitted
2016 Operating Hours	2357	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	11.9	g/hp-hr	<-- From 4/21/15 performance test
NO_X lb/hr:	20.99	lb/hr	<-- Calculated
NO_X tpy:	24.73	tpy	<-- Calculated

Clean Burn Technologies

NO_X guarantee:	83.2%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	2.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:	3.53	lb/hr	
NO_X tpy:	4.16	tpy	<--Calculated based on 2016 hr/yr
Total Cap Investment	$ 5,765,849		<--Vendor Quote
Annualized TCI:	$ 482,482		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 100,000		<--Client provided
Total Annual Costs:	$ 582,482		
Emissions Reduction:	20.58	tpy	
Cost Effectiveness:	**$ 28,307.47**	**$/ton**	

Clean Burn Technologies

NO_X guarantee:	58.0%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	5.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:	8.82	lb/hr	
NO_X tpy:	10.39	tpy	<--Calculated based on 2016 hr/yr
Equipment, install labor and materials	$ 956,153		<-- From Vendor
Auxiliary Cooling System	$ 558,250		<-- From Vendor
Fuel System Modification	$ 48,333.33		<-- Targa estimated
Custody Transfer Metering	$ 38,333.33		<-- Targa estimated
Electrical Power to MCC	$ 3,000,000.00		<-- Targa estimated
Permitting Cost	$ 7,500.00		<-- Targa estimated
Taxes, Contingency	$ 806,499.69		<-- Targa estimated
Total Cap Investment	**$ 5,415,069**		
Annualized TCI:	$ 453,129		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 100,000		<--Client provided
Total Annual Costs:	$ 553,129		
Emissions Reduction:	14.34	tpy	
Cost Effectiveness:	**$ 38,568.35**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark RA-8	Interest Rate:	5.50%	
Units: C-02	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	800	hp	<-- As permitted
2016 Operating Hours	4069	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	9.8	g/hp-hr	<-- From 4/21/15 performance test
NO_X lb/hr:	17.28	lb/hr	<-- Calculated
NO_X tpy:	35.16	tpy	<-- Calculated

Clean Burn Technologies

NO_X guarantee:	79.6%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:	3.53	lb/hr	
NO_X tpy:	7.18	tpy	
Total Cap Investment	$ 5,765,849		<--Manufacturer specification
Annualized TCI:	$ 482,482		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 100,000		<--Client provided
Total Annual Costs:	$ 582,482		
Emissions Reduction:	27.99	tpy	
Cost Effectiveness:	**$ 20,811.99**	**$/ton**	

Clean Burn Technologies

NO_X guarantee:	49.0%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	5.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:	8.82	lb/hr	
NO_X tpy:	17.94	tpy	
Equipment, install labor and materials	$ 956,153		<-- From Vendor
Auxiliary Cooling System	$ 558,250		<-- From Vendor
Fuel System Modification	$ 48,333.33		<-- Targa estimated
Custody Transfer Metering	$ 38,333.33		<-- Targa estimated
Electrical Power to MCC	$ 3,000,000.00		<-- Targa estimated
Permitting Cost	$ 7,500.00		<-- Targa estimated
Taxes, Contingency	$ 806,499.69		<-- Targa estimated
Total Cap Investment	**$ 5,415,069**		
Annualized TCI:	$ 453,129		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 100,000		<--Client provided
Total Annual Costs:	$ 553,129		
Emissions Reduction:	17.22	tpy	
Cost Effectiveness:	**$ 32,115.22**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark RA-6	Interest Rate:		5.50%	
Units: C-04	Period (yrs):		20	<-- EPA Guidance Default for SCR
Base Emissions				
Site Horsepower		600	hp	<-- As permitted
2016 Operating Hours		990	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)		9.9	g/hp-hr	<-- From 4/23/15 performance test
NO_X lb/hr:		13.10	lb/hr	<-- Calculated
NO_X tpy:		6.48	tpy	<-- Calculated

Clean Burn Technologies				
NO_X guarantee:		79.8%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:		2.65	lb/hr	
NO_X tpy:		1.31	tpy	<--Calculated based on 2016 hr/yr
Total Cap Investment	$	5,120,345		<--Vendor Quote
Annualized TCI:	$	428,467		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	528,467		
Emissions Reduction:		5.17	tpy	
Cost Effectiveness:	**$**	**102,166.24**	**$/ton**	

Clean Burn Technologies				
NO_X guarantee:		49.5%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		5.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:		6.61	lb/hr	
NO_X tpy:		3.27	tpy	<--Calculated based on 2016 hr/yr
Equipment, install labor and materials	$	914,621		<-- From Vendor
Auxiliary Cooling System	$	79,750		<-- From Vendor
Fuel System Modification	$	33,333		<-- Targa estimated
Custody Transfer Metering	$	24,000		<-- Targa estimated
Electrical Power to MCC	$	3,000,000		<-- Targa estimated
Permitting Cost	$	7,500		<-- Targa estimated
Taxes, Contingency	$	710,361		<-- Targa estimated
Total Cap Investment	$	4,769,565		
Annualized TCI:	$	399,114		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	499,114		
Emissions Reduction:		3.21	tpy	
Cost Effectiveness:	**$**	**155,568.00**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark RA-6	Interest Rate:	5.50%	
Units: C-05	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	600	hp	<-- As permitted
2016 Operating Hours	3938	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	8.4	g/hp-hr	<-- From 4/22/15 performance test
NO_X lb/hr:	11.11	lb/hr	<-- Calculated
NO_X tpy:	21.88	tpy	<-- Calculated

Clean Burn Technologies

NO_X guarantee:	76.2%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	2.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:	2.65	lb/hr	
NO_X tpy:	5.21	tpy	<--Calculated based on 2016 hr/yr
Total Cap Investment	$ 5,120,345		<--Vendor Quote
Annualized TCI:	$ 428,467		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 100,000		<--Client provided
Total Annual Costs:	$ 528,467		
Emissions Reduction:	16.67	tpy	
Cost Effectiveness:	**$ 31,704.00**	**$/ton**	

Clean Burn Technologies

NO_X guarantee:	40.5%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	5.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:	6.61	lb/hr	
NO_X tpy:	13.02	tpy	<--Calculated based on 2016 hr/yr
Equipment, install labor and materials	$ 914,621		<-- From Vendor
Auxiliary Cooling System	$ 79,750		<-- From Vendor
Fuel System Modification	$ 33,333		<-- Targa estimated
Custody Transfer Metering	$ 24,000		<-- Targa estimated
Electrical Power to MCC	$ 3,000,000		<-- Targa estimated
Permitting Cost	$ 7,500		<-- Targa estimated
Taxes, Contingency	$ 710,361		<-- Targa estimated
Total Cap Investment	$ 4,769,565		
Annualized TCI:	$ 399,114		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 100,000		<--Client provided
Total Annual Costs:	$ 499,114		
Emissions Reduction:	8.86	tpy	
Cost Effectiveness:	**$ 56,363.37**	**$/ton**	

Monument Gas Plant

2SLB Engine - Clark RA-6	Interest Rate:	5.50%	
Units: C-06	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	600	hp	<-- As permitted
2016 Operating Hours	2035	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	11.4	g/hp-hr	<-- From 4/21/15 performance test
NO_X lb/hr:	15.08	lb/hr	<-- Calculated
NO_X tpy:	15.34	tpy	<-- Calculated

Clean Burn Technologies

NO_X guarantee:	82.5%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	2.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:	2.65	lb/hr	
NO_X tpy:	2.69	tpy	<--Calculated based on 2016 hr/yr

Total Cap Investment	$	5,120,345	<--Vendor Quote
Annualized TCI:	$	428,467	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000	<--Client provided
Total Annual Costs:	$	528,467	
Emissions Reduction:		12.65 tpy	
Cost Effectiveness:	**$**	**41,771.25**	**$/ton**

Clean Burn Technologies

NO_X guarantee:	56.1%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	5.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:	6.61	lb/hr	
NO_X tpy:	6.73	tpy	<--Calculated based on 2016 hr/yr

Equipment, install labor and materials	$	914,621	<-- From Vendor
Auxiliary Cooling System	$	79,750	<-- From Vendor
Fuel System Modification	$	33,333	<-- Targa estimated
Custody Transfer Metering	$	24,000	<-- Targa estimated
Electrical Power to MCC	$	3,000,000	<-- Targa estimated
Permitting Cost	$	7,500	<-- Targa estimated
Taxes, Contingency	$	710,361	<-- Targa estimated
Total Cap Investment	$	4,769,565	
Annualized TCI:	$	399,114	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000	<--EPA Cost Estimate Spreadsheet
Total Annual Costs:	$	499,114	
Emissions Reduction:		8.61 tpy	
Cost Effectiveness:	**$**	**57,943.83**	**$/ton**

Monument Gas Plant

2SLB Engine - Clark HRA-8	Interest Rate:	5.50%	
Units: C-24	Period (yrs):	20	<-- EPA Guidance Default for SCR

Base Emissions			
Site Horsepower	880	hp	<-- As permitted
2016 Operating Hours	6610	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)	18.2	g/hp-hr	<-- From 4/22/15 performance test
NO_X lb/hr:	35.31	lb/hr	<-- Calculated
NO_X tpy:	116.70	tpy	<-- Calculated

Clean Burn Technologies

NO_X guarantee:	89.0%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	2.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:	3.88	lb/hr	
NO_X tpy:	12.82	tpy	<--Calculated based on 2016 hr/yr

Total Cap Investment	$	5,765,849	<--Vendor Quote
Annualized TCI:	$	482,482	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000	<--Client provided
Total Annual Costs:	$	582,482	
Emissions Reduction:		103.87 tpy	
Cost Effectiveness:	**$**	**5,607.73**	**$/ton**

Clean Burn Technologies

NO_X guarantee:	72.5%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:	5.00	g/hp-hr	<--Manufacturer specifications
NO_X lb/hr:	9.70	lb/hr	
NO_X tpy:	32.06	tpy	<--Calculated based on 2016 hr/yr

Equipment, install labor and materials	$	956,153	<-- From Vendor
Auxiliary Cooling System	$	558,250	<-- From Vendor
Fuel System Modification	$	48,333.33	<-- Targa estimated
Custody Transfer Metering	$	38,333.33	<-- Targa estimated
Electrical Power to MCC	$	3,000,000.00	<-- Targa estimated
Permitting Cost	$	7,500.00	<-- Targa estimated
Taxes, Contingency	$	806,499.69	<-- Targa estimated
Total Cap Investment	**$**	**5,415,069**	
Annualized TCI:	$	453,129	<-- Based on interest rate, year and TCI
Annual O&M Costs:	**$**	**100,000**	<--Client provided
Total Annual Costs:	$	553,129	
Emissions Reduction:		84.64 tpy	
Cost Effectiveness:	**$**	**6,535.39**	**$/ton**

Monument Gas Plant

2SLB Engine - Cooper Bessemer GMVA-8	Interest Rate:		5.50%	
Units: C-28	Period (yrs):		20	<-- EPA Guidance Default for SCR
Base Emissions				
Site Horsepower		1100	hp	<-- As permitted
2016 Operating Hours		573	hours/yr	<-- From 2016 EI calculations
NO_X EF (g/hp-hr)		6.3	g/hp-hr	<-- From 4/23/15 performance test
NO_X lb/hr:		15.28	lb/hr	<-- Calculated
NO_X tpy:		4.38	tpy	<-- Calculated
Clean Burn Technologies				
NO_X guarantee:		68.3%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		2.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		4.85	lb/hr	
NO_X tpy:		1.39	tpy	
Total Cap Investment	$	900,000		<--Manufacturer specification + Engineering
Annualized TCI:	$	75,311		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<--Client provided
Total Annual Costs:	$	175,311		
Emissions Reduction:		2.99	tpy	
Cost Effectiveness:	**$**	**58,680.99**	**$/ton**	
Clean Burn Technologies				
NO_X guarantee:		36.5%	Control Eff.	<-- Calculated $(NO_{X(in)} - NO_{X(out)})/NO_{X(in)}$
NO_X EF guarantee:		4.00	g/hp-hr	<-- Manufacturer specification
NO_X lb/hr:		9.70	lb/hr	
NO_X tpy:		2.78	tpy	
Total Cap Investment	$	805,000		<--Manufacturer specification + Engineering
Annualized TCI:	$	67,362		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	100,000		<-- From Vendor
Total Annual Costs:	$	167,362		
Emissions Reduction:		1.60	tpy	
Cost Effectiveness:	**$**	**104,733.21**	**$/ton**	

Trinity Consultants
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November 20, 2020

Mr. Ted Schooley
Permit Programs Manager
NMED Air Quality Bureau
525 Camino de los Marquez Suite 1
Santa Fe, NM 87505-1816

RE: Targa Midstream Services LLC; Eunice, Monument, and Saunders Gas Plants
Four Factor Analysis NMED Follow-up Response

Dear Mr. Schooley:

On behalf of Targa Midstream Services LLC, we are submitting a response to the follow-up information request email received from the NMED September 14, 2020 regarding the Four Factor Analyses for the Eunice, Monument, and Saunders Gas Plants. Each question and response are included below.

Overarching:

1. *A technical feasibility analysis for electric compression is being requested from all facilities with compressors and turbines, and if feasible, then a four-factor analysis with cost estimations is required. Please provide some info on the compression that has already been converted to electric power as part of the discussion.*

   Targa has determined that installation of electric compression at the Eunice and Monument Gas Plants is technically feasible, provided sufficient time and resources. Saunders Gas Plant currently does not have third party electricity installed to handle operating the plant. Targa has not done an evaluation of bringing power into the Saunders Plant. Targa currently operates 4 natural gas fired generators (G-1, G-2, G-3, and G-4) to supply power to operate the Saunders plant.

   A four-factor analysis of the control is included below; however, Targa objects to the consideration of this change as the installation of electric compression would fundamentally redefine the sources subject to this analysis, the existing permitted engines. The EPA's policy since 1988 has been that control options which fundamentally redefine a proposed source can be excluded from consideration in BACT analyses. This policy derives from the understanding that the permit issuer must only consider control options that align with how the applicant, in proposing the facility, defines the purpose or basic design for the permitted facility. In initial development of the policy, the Administrator concluded that permit conditions defining the emissions control systems "are imposed on the source as the applicant has defined it" and that "the source itself is not a condition of the permit." [1]

   Furthermore, 40 CFR 51 Appendix Y states: "We do not consider BART as a requirement to redesign the source when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, we do not require the BART analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting on a per unit basis." [2]

   Targa does not consider the replacement of existing permitted units with electric compression a reasonable option for emission reduction within the scope of the Regional Haze Rule.

[1] In re Pennsauken County, N.J., Res. Recovery Facility, 2 E.A.D. 667, 673 (Adm'r 1988)

[2] 40 CFR 51 Appendix Y: Guidelines for BART Determinations Under the Regional Haze Rule, Section IV.D.1.5.

a) **Cost of Compliance**

The cost estimates for electric compression at the Eunice and Monument Gas Plants are summarized below in Table 1 and Table 2, respectively. Calculations for the below estimates are provided in Appendix A. These costs include the capital cost of the electrical substations that would be necessary to be built, as well as the capital cost of environmental permitting for the facility changes, and the cost of the new compression equipment. Annual operating and maintenance costs are estimated for the electricity cost of the units, compressor maintenance cost, and cost of labor for maintaining the units.

Table 1: Cost analysis summary of electric compression at Eunice Gas Plant

Unit	Substation Capital Cost ($)	Permitting Capital Cost ($)	Compression Capital Cost ($)	Annual O&M Cost ($)	Total Annual Cost ($)	Emission Reduction (tpy)	Individual Cost Effectiveness ($/ton)	Cumulative Cost Effectiveness ($/ton)
C-01	$ 4,000,000.0	$ 40,000.0			$ 1,963,244.5	135.14	$ 14,528.02	
C-02	$ 4,000,000.0	$ 40,000.0	$ 6,944,444.4	$ 1,207,746.7	$ 1,963,244.5	84.11	$ 23,342.78	$ 7,306.59
C-03	$ 4,000,000.0	$ 40,000.0			$ 1,963,244.5	49.46	$ 39,697.59	
C-04	$ 4,000,000.0	$ 40,000.0			$ 1,963,244.5	113.30	$ 17,328.61	
C-05	$ 4,000,000.0	$ 40,000.0	$ 6,944,444.4	$ 1,207,746.7	$ 1,963,244.5	97.97	$ 20,040.26	$ 5,779.77
C-06	$ 4,000,000.0	$ 40,000.0			$ 1,963,244.5	128.42	$ 15,288.28	
C-07	$ 4,000,000.0	$ 40,000.0	$ 6,944,444.4	$ 1,207,746.7	$ 1,963,244.5	141.23	$ 13,901.54	$ 4,947.76
C-13	$ 4,000,000.0	$ 40,000.0			$ 1,963,244.5	255.57	$ 7,681.83	

Table 2: Cost analysis summary of electric compression at Monument Gas Plant

Unit	Substation Capital Cost ($)	Permitting Capital Cost ($)	Compression Capital Cost ($)	Annual O&M Cost ($)	Total Annual Cost ($)	Emission Reduction (tpy)	Individual Cost Effectiveness ($/ton)	Cumulative Cost Effectiveness ($/ton)
C-01	$ 4,000,000.0	$ 60,000.0	$ 4,325,000.0	$ 551,620.0	$ 1,128,330.9	42.53	$ 26,531.17	$ 13,797.40
C-02	$ 4,000,000.0	$ 60,000.0			$ 1,128,330.9	39.25	$ 28,747.29	
C-04	$ 4,000,000.0	$ 60,000.0			$ 1,128,330.9	18.76	$ 60,145.57	
C-05	$ 4,000,000.0	$ 60,000.0	$ 4,325,000.0	$ 551,620.0	$ 1,128,330.9	24.09	$ 46,838.15	$ 14,895.46
C-06	$ 4,000,000.0	$ 60,000.0			$ 1,128,330.9	32.90	$ 34,295.77	
C-24	$ 4,000,000.0	$ 60,000.0	$ 4,500,000.0	$ 463,240.0	$ 1,051,987.2	133.79	N/A	$ 7,862.97
C-28	$ 4,000,000.0	$ 60,000.0	$ 7,000,000.0	$ 463,240.0	$ 1,223,934.5	8.59	N/A	$ 142,483.64

Eunice Gas Plant

One (1) 3,250 hp electric compressor will be needed to replace approximately three (3) of the existing Clark engines. To replace all existing engines, a total of (5) 3,250 hp electric compressors will be needed. Targa has estimated the cost of compliance for this action using two methods in Table 1. The Individual Cost Effectiveness provided represents the cost to replace an individual permitted engine, dividing the Total Annual Cost of the upgrade by the anticipated Emission Reduction of a single unit. This allows Targa to estimate the cost effectiveness on a unit-by unit basis as is necessary for the Four Factor Analysis process. The Cumulative Cost Effectiveness represents the cost effectiveness of the replacement assuming that the single new electric compressor assumes its maximum potential load, or approximately three (3) existing permitted engines, and represents the Total Annual Cost divided by the emission reduction of all units that could potentially be replaced. It will be necessary to build a new electrical substation and re-permit the facility regardless of the number of replacements; therefore, those costs have been included for each batch of replacements. Annual O&M costs are detailed in the attached cost estimate spreadsheets.

The following Capital Costs have been applied in the Eunice assessments:

Table 3: Costs to Replace Eunice Clark BA-6 3rd stage; C-01, 02, 03, 04, 05, 06, 07, 13

Description	Estimated Costs
(5) 3250 hp compressor units installed	$ 20,833,333
Additional substation /power / MCC for needed power	$ 4,000,000
Permitting Cost	$ 40,000
Annual O&M Cost	$ 3,623,240
Total Cost	**$ 28,496,573**

Monument Gas Plant

Monument Clark 3rd stage; C-01, 02, 04, 05, 06

Three (3) 1,750 hp electric compressors will be necessary to replace existing 3rd stage engine units C-01, 02, 04, 05, and 06. It is approximated for this analysis that one of the new compressors would replace the existing Clark RA-8 engines (C-01 and C-02) and the second new compressor would replace the Clark RA-6 engines (C-04, C-05, and C-06).

The Individual Cost Effectiveness provided in cost analysis summary Table 2 represents the cost to replace an individual permitted engine, dividing the Total Annual Cost of electric compression by the anticipated Emission Reduction of a single unit. This allows Targa to estimate the cost effectiveness on a unit-by unit basis as is necessary for the Four Factor Analysis process. The Cumulative Cost Effectiveness represents the cost effectiveness of the replacement assuming that the single new electric compressor assumes its maximum potential load, taking on the load of all the existing Clark RA-8 or RA-6 engines. It will be necessary to build the electrical substation and re-permit the facility regardless of the number of replacements; therefore, those costs have been included for each batch of replacements. Annual O&M costs are detailed in the attached cost estimate spreadsheets.

The following Capital Costs have been applied in the Monument assessments for units C-01, 02, 04, 05, and 06:

Table 4: Costs to Replace Monument Clark 3rd stage; C-01, 02, 04, 05, 06

Description	Estimated Costs
(2) 1750HP 3rd stage units, VFDs, installed (based on Baesl estimate)	$ 8,250,000
Relocation / reconstruction of shop/storage	$ 200,000
Additional substation / power (for all conversions)	$ 4,000,000
Permitting cost	$ 60,000
Annual O&M Cost	$ 1,103,240
Total Cost	**$ 12,510,000**

Monument Clark HRA-8 1st & 2nd stages; C-24

One (1) 1,250 hp electric compressor unit will be necessary to replace the existing Clark HRA-8, unit C-24. The following Capital Costs have been applied in the Monument assessment for unit C-24:

Table 5: Costs to Replace Monument Clark HRA-8 1st & 2nd stages; C-24

Description	Estimated Costs
(1) 1250HP 1st & 2nd stage unit, VFD, installed	$ 3,500,000
Additional substation / power / MCC	$ 4,000,000
Additional wire trays / wire to C-24 location	$ 500,000
Removal and foundation work on C-24 for electric skid	$ 500,000
Permitting cost	$ 60,000
Annual O&M Cost	$ 463,240
Total Cost	**$ 9,023,240**

Monument Cooper GMVA-10 Refrigeration; C-28

One (1) 1,250 hp electric compressor unit will be necessary to replace existing Cooper GMVA-10, C-28. The following Capital Costs have been applied in the Monument assessment for unit C-28:

Table 6: Costs to Replace Monument Cooper GMVA-10 Refrigeration, C-28

Description	Estimated Costs
(1) 1250HP Refrig unit, VFD, installed	$ 7,000,000
Additional substation / power / MCC	$ 4,000,000
Additional wire trays / wire to C-28 location	$ 500,000
Header work to set unit outside C-28 location near propane scrubber	$ 200,000
Permitting cost (included above)	$ 60,000
Annual O&M Cost	$ 463,240
Total Cost	**$ 12,223,240**

b) **Time Necessary for Compliance**
Targa is unable to determine an exact time needed for compliance, as a large portion of the schedule for each project would be dependent on the availability of the power company to construct the required electrical substations. Targa would also like to note that their past experience with the power company

indicates that scheduling obligations may not be honored during construction of the substations. Considering those items, Targa conservatively estimates that 7-8 years would be needed to budget, design, procure, and construct all the equipment necessary at the substations and gas plants. This includes time for the power company to permit and construct the new electricity line to the plants, build the substation, and replace the units. Due to the extremely high costs, this would need to be split over several years.

c) **Energy and Non-Air Quality Environmental Impacts of Compliance**
This control will require a significant amount of electrical power to operate. This requirement will cause strain on the electrical grid and require new electrical substations to be built at each site. The physical footprint of the substation, powerlines, and access roads to be installed would have a detrimental impact on vegetation and wildlife in the area as well as exclude the land from the potential for future beneficial use. Furthermore, the EPA indicates that much of the equipment used in electricity transmission and distribution is insulated with sulfur hexafluoride, a powerful greenhouse gas which could be released during maintenance or as the facility ages.

d) Remaining Useful Life of Sources
The estimated useful life of the electric compressors is 20 years, based on industry standards for the life of these units.

2. *How were the annual O&M costs determined?*
Annual O&M costs are estimated by Targa using representative information from similar facilities and equipment. Targa estimated the direct annual costs (maintenance, operating labor, reagent cost, electricity cost, catalyst cost, etc.) and indirect annual costs associated with Targa's internal labor, overhead and capital recovery for the project. The costs associated with the 2SLB engines only included the maintenance and operating cost of the clean burn technology and not the costs for the existing engines. In our previous cost estimates provided we did not include the cost of electricity needed for the blowers that are required as part of the clean burn technology. Therefore, we have updated the cost estimates and they are provided in the attached cost estimate spreadsheet.

3. *Was the bank prime rate verified and/or documented during preparation of the analysis? The default rate of 5.5% was used in the analysis; however, it has been changed to the current bank prime rate of 3.25% in NMED's calculations.*
The bank prime rate used in the original analysis was verified as accurate during preparation of the analysis in October 2019. It has since dropped due to the national economic downturn. Targa has adjusted the rate to 3.25% for the costs provided above; however, Targa would like to note that 5.41% is a more realistic capitalized interest rate for the company, based on a review of the current company-specific economic status.

4. *Describe the potential issues with having enough power in existing substation and new substations for additional controls.*
Targa's Monument and Eunice Gas Plants have existing substations. However, an additional substation would need to be built to handle additional electricity load at both the Eunice and Monument Gas Plants, as the current substations are at or nearly at capacity. The amount of electricity needed for adding clean burn technology would require a new substation to be built at the site and additional electricity lines installed to the plants by the power company.

Targa Monument:

1. *In your 4FA you stated that installation of redundant electric compression for the AGI well system was required pursuant to a Settlement Agreement and Stipulated Final Compliance Order; and that installation should be complete by 9/1/20. Has this been completed?*
Targa's deadline to complete the agreed Supplemental Environmental Project (SEP) as part of the Settlement Agreement and Stipulated Final Compliance Order (SASFCO) TAR-0610-1701 was 24 months, or December 28, 2020 (II.B.17). However, Targa received an extension via email from Shannon Duran, dated 5/15/2020, extending

the SEP completion deadline to 3/31/2021. Targa has completed construction on the additional compression unit and expects the unit at Monument to start operation before the end of the year.

Targa Eunice:

1. *When were the LNB control installed on the boilers?*
   The exact date the LNB controls were installed is unknown. It is estimated that they were installed over 10 years ago.

2. *What is the new schedule on installation of redundant compression?*
   Targa's deadline to complete the agreed Supplemental Environmental Project (SEP) as part of the Settlement Agreement and Stipulated Final Compliance Order (SASFCO) TAR-0610-1701 was 24 months, or December 28, 2020 (II.B.17). However, Targa received an extension via email from Shannon Duran, dated 5/15/2020, extending the SEP completion deadline to 3/31/2021. Targa's permit amendment was issued on 9/17/2020. Targa intends to start construction at Eunice once the Monument unit is in service and expect to have the compressor operationally before the March 2021 deadline.

Targa Saunders:

1. *In the cost calculations for potential controls for the amine unit, the base case emissions for the acid gas emergency flare (F-01) indicate 29.5 tons SO2 for 2016. Reviewing the information pulled from the AEIR, we show 0.29 tons SO2 for 2016. Please verify the value submitted for this unit in 2016 in case this needs to be corrected. A rate of 29.5 tons in 2016 seems reasonable when compared to 2017 (29.9 tons) and 2018 (35.2 tons).*
   The 29.5 tons SO_2 for 2016 is the correct value for F-01. There was a typo in the EI. We are investigating what we need to do with the EI group on this error.

Please feel free to contact me at (480) 760-3860 or Melanie Roberts at (713) 584-1424 if you have any questions regarding this response.

Sincerely,

TRINITY CONSULTANTS

Adam Erenstein
Manager of Consulting Services

Cc: Melanie Roberts (TARGA)
Trinity Project File: 203201.0132

Appendix A: Eunice and Monument Electric Compression Cost Effectiveness Calculations

Targa Eunice Engines

Assumed Discount Rate - "r"	3.25%	changed bank prime rate
Life Expectancy of Clean Burn (years) - "n"	20	

Equipment, install labor and materials	$ 20,833,333	<-- Targa estimated
Total Cost to replace all existing engines, a total of (5) 3,250HP compressors will be needed.		
Electrical Power to MCC	$ 4,000,000	<-- Targa estimated
Permitting Cost	$ 40,000	<-- Trinity estimated (includes estimated cost of labor and review fee)
Annual O&M Costs:	$ 3,623,240	<-- Targa estimated; electricity, compressor maintenance, and labor costs
		($0.053/kW-h electricity costs, $25/BHP maintenance cost, 54 labor hours/yr at 60$/hr)
Total Cost:	**$ 28,496,573**	

Cost of Compliance

Unit	Substation Capital Cost ($)	Permitting Capital Cost ($)	Compression Capital Cost ($)[1]	Annual O&M Cost ($)[2]	Total Annual Cost ($)[3]	Emission Reduction (tpy)[4]	Individual Cost Effectiveness ($/ton)[5]	Cumulative Cost Effectiveness ($/ton)[6]
C-01	$ 4,000,000.0	$ 40,000.0			$ 1,963,244.5	135.14	$ 14,528.02	
C-02	$ 4,000,000.0	$ 40,000.0	$ 6,944,444.4	$ 1,207,746.7	$ 1,963,244.5	84.11	$ 23,342.78	$ 7,306.59
C-03	$ 4,000,000.0	$ 40,000.0			$ 1,963,244.5	49.46	$ 39,697.59	
C-04	$ 4,000,000.0	$ 40,000.0			$ 1,963,244.5	113.30	$ 17,328.61	
C-05	$ 4,000,000.0	$ 40,000.0	$ 6,944,444.4	$ 1,207,746.7	$ 1,963,244.5	97.97	$ 20,040.26	$ 5,779.77
C-06	$ 4,000,000.0	$ 40,000.0			$ 1,963,244.5	128.42	$ 15,288.28	
C-07	$ 4,000,000.0	$ 40,000.0	$ 6,944,444.4	$ 1,207,746.7	$ 1,963,244.5	141.23	$ 13,901.54	$ 4,947.76
C-13	$ 4,000,000.0	$ 40,000.0			$ 1,963,244.5	255.57	$ 7,681.83	

[1] Cost of (1) 3,250HP compressor and (1/3) cost of backup units.

[2] (1/3) of total estimated annual O&M costs.

[3] Amortized total annual cost based on interest rate, year and TCI per NMED calculation methodology, including cost of substation and permitting.

[4] Average of 2016-18 Emissions Inventory; AEIR.

[5] Individual Cost Effectiveness represents the cost to replace an individual permitted engine, comparing the Total Annual Cost to the anticipated Emission Reduction of a single unit.

[6] Cumulative Cost Effectiveness represents the cost effectiveness of the replacement assuming that the single new electric compressor assumes its maximum potential load, or approximately three (3) existing permitted engines.

Targa Monument Engines

Assumed Discount Rate - "r"	3.25%	changed bank prime rate
Life Expectancy of Clean Burn (years) - "n"	20	

Monument Clark 3rd stages, C-01, 02, 04, 05, 06 RA-6 & 8 units

Equipment, install labor and materials	$ 8,250,000	<-- Targa estimated
Total Cost to replace existing engines, a total of (3) 1750HP 3rd stage compressor units will be needed.		
Electrical Power to MCC	$ 4,000,000	<-- Targa estimated
Relocation / reconstruction of shop/storage	$ 200,000	<-- Targa estimated
Permitting Cost	$ 60,000	<-- Trinity estimated (includes estimated cost of labor and review fee)
Annual O&M Costs:	$ 1,103,240	<-- Targa estimated; electricity, compressor maintenance, and labor costs
		($0.053/kW-h electricity costs, $75/BHP engine maintenance cost, $25/BHP compressor maintenance cost, 54 labor hours/yr at 60$/hr)
Total Cost:	**$ 12,510,000**	

Cost of Compliance

Unit	Substation Capital Cost ($)	Permitting Capital Cost ($)	Compression Capital Cost ($)[1]	Annual O&M Cost ($)[2]	Total Annual Cost ($)[3]	Emission Reduction (tpy)[4]	Individual Cost Effectiveness ($/ton)[5]	Cumulative Cost Effectiveness ($/ton)[6]
C-01	$ 4,000,000.0	$ 60,000.0	$ 4,325,000.0	$ 551,620.0	$ 1,128,330.9	42.53	$ 26,531.17	$ 13,797.40
C-02	$ 4,000,000.0	$ 60,000.0			$ 1,128,330.9	39.25	$ 28,747.29	
C-04	$ 4,000,000.0	$ 60,000.0			$ 1,128,330.9	18.76	$ 60,145.57	
C-05	$ 4,000,000.0	$ 60,000.0	$ 4,325,000.0	$ 551,620.0	$ 1,128,330.9	24.09	$ 46,838.15	$ 14,895.46
C-06	$ 4,000,000.0	$ 60,000.0			$ 1,128,330.9	32.90	$ 34,295.77	

[1] Cost of (1) 1750HP 3rd stage compressor unit and (1/2) cost of backup unit.

[2] (1/2) of total estimated annual O&M costs.

[3] Amortized total annual cost based on interest rate, year and TCI per NMED calculation methodology, including cost of substation and permitting.

[4] Average of 2016-18 Emissions Inventory; AEIR.

[5] Individual Cost Effectiveness represents the cost to replace an individual permitted engine, comparing the Total Annual Cost to the anticipated Emission Reduction of a single unit.

[6] Cumulative Cost Effectiveness represents the cost effectiveness of the replacement assuming that the single new electric compressor assumes its maximum potential load, or approximately three (3) existing permitted engines.

Targa Monument Engines

Assumed Discount Rate - "r"	3.25%	changed bank prime rate
Life Expectancy of Clean Burn (years) - "n"	20	

Monument Clark HRA-8 1st & 2nd stage, C-24

Equipment, install labor and materials	$	3,500,000	<-- Targa estimated
Cost of (1) 1250HP 1st & 2nd stage replacement unit, VFD, installed			
Electrical Power to MCC	$	4,000,000	<-- Targa estimated
Additional wire trays / wire to C-24 location	$	500,000	<-- Targa estimated
Removal and foundation work on C-24 for electric skid	$	500,000	<-- Targa estimated
Permitting Cost	$	60,000	<-- Trinity estimated (includes estimated cost of labor and review fee)
Annual O&M Costs:	$	463,240	<-- Targa estimated; electricity, compressor maintenance, and labor costs
			($0.053/kW-h electricity costs, $75/BHP engine maintenance cost, $25/BHP compressor maintenance cost, 54 labor hours/yr at 60$/hr)
Total Cost:	**$**	**9,023,240**	

Unit	Substation Capital Cost ($)	Permitting Capital Cost ($)	Compression Capital Cost ($)[1]	Annual O&M Cost ($)[2]	Total Annual Cost ($)[3]	Emission Reduction (tpy)[4]	Cost Effectiveness ($/ton)
C-24	$ 4,000,000.0	$ 60,000.0	$ 4,500,000.0	$ 463,240.0	$ 1,051,987.2	133.79	$ 7,862.97

[1] Cost of (1) 1250HP 1st & 2nd stage replacement unit, VFD

[2] Includes equipment, installation labor and materials, additional wire trays/wire to location, and removal and foundation work.

[3] Amortized total annual cost based on interest rate, year and TCI per NMED calculation methodology, including cost of substation and permitting.

[4] Average of 2016-18 Emissions Inventory; AEIR.

Monument Cooper GMVA-10 Refrig, C-28

Equipment, install labor and materials	$	7,000,000	<-- Targa estimated
Cost of (1) 1250HP Refrig unit, VFD, and (1) backup unit.			
Electrical Power to MCC	$	4,000,000	<-- Targa estimated
Additional wire trays / wire to C-28 location	$	500,000	<-- Targa estimated
Header work to set unit outside C-28 location	$	200,000	<-- Targa estimated
Permitting Cost	$	60,000	<-- Trinity estimated (includes estimated cost of labor and review fee)
Annual O&M Costs:	$	463,240	<-- Targa estimated; electricity, compressor maintenance, and labor costs
			($0.053/kW-h electricity costs, $75/BHP engine maintenance cost, $25/BHP compressor maintenance cost, 54 labor hours/yr at 60$/hr)
Total Cost:	**$**	**12,223,240**	

Unit	Substation Capital Cost ($)	Permitting Capital Cost ($)	Compression Capital Cost ($)[1]	Annual O&M Cost ($)[2]	Total Annual Cost ($)[3]	Emission Reduction (tpy)[4]	Cost Effectiveness ($/ton)
C-28	$ 4,000,000.0	$ 60,000.0	$ 7,000,000.0	$ 463,240.0	$ 1,223,934.5	8.59	$ 142,483.64

[1] Cost of (1) 1250HP Refrig unit, VFD, and (1) backup unit.

[2] Includes equipment, installation labor and materials, additional wire trays/wire to location, and header work.

[3] Amortized total annual cost based on interest rate, year and TCI per NMED calculation methodology, including cost of substation and permitting.

[4] Average of 2016-18 Emissions Inventory; AEIR.

From:	Roberts, Melanie A.
To:	Jones, Mark, ENV; Singleton,Kerwin, NMENV; Baca, Michael, ENV; Butt, Neal, ENV
Cc:	Peterson, Kim A.; Klein, Cindy S.; Sittler, Martina G.; Knight, Andrew, ENV
Subject:	[EXT] RE: Follow-up clarifying questions Dec 18, 2020 / RE: [EXTERNAL] RE: Targa Four Factor Analyses
Date:	Tuesday, February 16, 2021 10:21:10 AM
Attachments:	Eunice-CleanBurnCosts.pdf

Below are Targa's responses to your questions.

From: Jones, Mark, NMENV <Mark.Jones@state.nm.us>
Sent: Friday, December 18, 2020 4:30 PM
To: Roberts, Melanie A. <MRoberts@targaresources.com>; Singleton,Kerwin, NMENV <Kerwin.Singleton@state.nm.us>; Baca, Michael, NMENV <michael.baca1@state.nm.us>; Butt, Neal, NMENV <Neal.Butt@state.nm.us>
Cc: Peterson, Kim A. <KPeterson@targaresources.com>; Klein, Cindy S. <CynthiaKlein@targaresources.com>; Sittler, Martina G. <msittler@targaresources.com>; Knight, Andrew, NMENV <Andrew.Knight@state.nm.us>
Subject: Follow-up clarifying questions Dec 18, 2020 / RE: [EXTERNAL] RE: Targa Four Factor Analyses

Thanks, Melanie, for the latest information submittal on Targa's Four Factor Analysis. We are nearing the end of wrapping up our Four Factor analyses and want to make sure our analyses are as accurate and representative as possible to then be evaluated in our long term strategy. In order to accomplish this, we have a few follow-up questions regarding your submittal:

1. Concerning the interest rate, Targa has stated that "The bank prime rate used in the original analysis was verified as accurate during preparation of the analysis in October 2019. It has since dropped due to the national economic downturn. Targa has adjusted the rate to 3.25% for the costs provided to the AQB; however, Targa would like to note that 5.41% is a more realistic capitalized interest rate for the company, based on a review of the current company-specific economic status." If Targa wants AQB to use a 5.41% interest rate in their calculations, then we will require that you provide documentation to support your proposed interest rate. This could be a letter from the chief financial officer for the institution that lends to your company, or from an official with your company (your company's CFO, for instance) that is in a position to know your company's costs of debt and equity.

   We are working on getting documentation on the interest rate but since we don't have it at this time please move ahead at the current 3.25%. We will continue to look into getting an official letter.

2. Electrification of engines at Monument and Eunice Gas Plants.

   a. The cost analysis you provided on 11/23/2020 is not clear as to whether the $4,000,000 capital costs for a substation and the $60,000 cost for permitting a particular engine should be applied to each individual engine or apportioned across all electrified compressors at that station. Can you clarify?

      The issue with the Four Factor Analysis is that you must look at each individual unit. If we are required to replace 1 unit with electric compression, we will need to build a substation expansion to bring in more electrical power. Therefore, we have included the cost for the substation with each engine cost calculation. However, the cost would only be incurred once

at the site even if we were required to replace multiple units. Splitting the cost across the units would unfairly reduce the cost per engine in the case that only 1 or 2 units required add-on controls.

b. At Monument Gas Plant, could the operating and maintenance costs of $1,103,240 also be apportioned over five engines; as well as dividing the O&M cost of $463,240 across the remaining two engines? Can this method be applied to the costs for Eunice Gas Plant?

Yes, the operating and maintenance cost of $1,103,240 was the total O&M costs for replacing the five 3rd stage engines. This cost should be divided out to the individual engines being replaced. However, it was hard to split it out since electric compression replacement would not be a 1:1 unit replacement.

3. In your calculations for the electrification of compressors operating and maintenance costs, of which the cost of electricity seems to be the overwhelming contributor, did you subtract the cost savings for the natural gas that would otherwise be combusted in the gas-fired engines?

No, we did not subtract any fuel charges for shutting down the gas fired units.

4. These questions of individual engine versus groupings of engines also apply to any revised costs that would be made for clean burn technology for Eunice and Monument Gas Plants. Appendix A is labelled, "Eunice and Monument Electric Compression Cost Effectiveness Calculations" but earlier in the text it refers to this section as having revised info for clean burn technology electrical substation capital costs and electrical O&M requirement costs. Please clarify and specify which costs need to be applied to single engines versus the entire group of engines being controlled. Is there an additional spreadsheet that was not attached?

Clean burn technology is the add-on control evaluated for the existing engines. So, it would be an individual emission calculation except for the substation capital cost. This would be the same explanation we provided in #2a for electric drive units. If we add clean burn controls to a single unit, we will need to upgrade the substation. But it would be a one-time cost even if controls are required on multiple units. However, since the analysis is on an individual unit basis, we included the capital cost of the substation to each unit being evaluated.

We inadvertently left out the revised Clean Burn Engine Control spreadsheet for Eunice. The spreadsheet is now attached. For the revised Clean Burn Control O&M cost at Eunice we have revised the costs to include electricity for the new blower plus costs for pressure and temperature sensor calibrations and replacement, increased spark plug replacements, blower required maintenance and replacement or refurbishment approximately every 5-8 years. This totaled $200,000 per unit. Monument engines with smaller blowers totaled $100,000 per unit, which is what was previously used. Annual electricity cost was estimated to be $164,000/unit for Eunice engines for the 400 hp blower and $58,000/unit for Monument engine 160 hp blower.

5. Regarding the Operation and Maintenance (O&M) costs for all facilities, do these values reflect the incremental cost of O&M, i.e., costs over and above those already realized for the units?

For the Clean Burn controls the O&M costs only include the incremental cost of O&M on the added controls. For the replacement units, there was no evaluation of current cost of the units evaluated since we would be installing new units.

We are willing to arrange a TEAMS call to discuss the questions and answers at your convenience,

but need to finalize our 4-factor analysis by early January so the earlier the better. These questions are key in our evaluation and the topics have also been discussed with us by EPA, FLMS, and other stakeholders in the regional haze process.

Thank you,

Mark Jones
Environmental Analyst
New Mexico Environment Department
Air Quality Bureau
1800 E. 30th St. Suite B
Farmington, NM 87401
Office: (505) 566-9746
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https://www.env.nm.gov/
"Innovation, Science, Collaboration, Compliance"

Targa Eunice Engines

Targa Amortization of Clean Burn equipment

Assumed Discount Rate - "r"	3.25%	changed bank prime rate
Total Capital Outlay (TCI) for Clean Burn (each) - "P"	$ 5,303,408	
Life Expectancy of Clean Burn (years) - "n"	20	
Annualized TCI - "A"	$ 364,762	
Annual O&M Costs	$ 175,000	**Targa has revised the O&M costs based on electrical cost of
Total Annual Costs	$ 539,762	$164,000/yr for 400hp electric blower. Plus $25/hp

$$A = P\frac{r(1+r)^n}{(1+r)^n - 1}$$

Engine 1 -C01

Baseline NOx Emissions (tpy)	135.14	(average of 2016-18 Emissions Inventory AEIR)
Emissions with Clean Burn (tpy)	17.62	(based on 2g/hp-hr capability)
Emissions Reduction (tpy)	117.5	
% Reduction	87.0%	
Cost: $/yr-ton	$ 4,593.0	

Engine 2 -C02

Baseline NOx Emissions (tpy)	84.11	(average of 2016-18 Emissions Inventory AEIR)
Emissions with Clean Burn (tpy)	16.00	(based on 2g/hp-hr capability)
Emissions Reduction (tpy)	68.1	
% Reduction	81.0%	
Cost: $/yr-ton	$ 7,925	

***Engine 3 -C03**

Baseline NOx Emissions (tpy)	49.46	(average of 2016-18 Emissions Inventory AEIR)
Emissions with Clean Burn (tpy)	17.6	(based on 2g/hp-hr capability)
Emissions Reduction (tpy)	31.9	
% Reduction	64.4%	
Cost: $/yr-ton	$ 16,935	

Engine 4 -C04

Baseline NOx Emissions (tpy)	113.30	(average of 2016-18 Emissions Inventory AEIR)
Emissions with Clean Burn (tpy)	16.6	(based on 2g/hp-hr capability)
Emissions Reduction (tpy)	96.7	
% Reduction	85.4%	
Cost: $/yr-ton	$ 5,580	

Engine 5 -C05

Baseline NOx Emissions (tpy)	97.97	(average of 2016-18 Emissions Inventory AEIR)
Emissions with Clean Burn (tpy)	18.1	(based on 2g/hp-hr capability)
Emissions Reduction (tpy)	79.9	
% Reduction	81.5%	
Cost: $/yr-ton	$ 6,759	

Engine 6 -C06

Baseline NOx Emissions (tpy)	128.42	(average of 2016-18 Emissions Inventory AEIR)
Emissions with Clean Burn (tpy)	16.6	(based on 2g/hp-hr capability)
Emissions Reduction (tpy)	111.8	
% Reduction	87.1%	
Cost: $/yr-ton	$ 4,828	

Engine 7 -C07

Baseline NOx Emissions (tpy)	141.23	(average of 2016-18 Emissions Inventory AEIR)
Emissions with Clean Burn (tpy)	17.7	(based on 2g/hp-hr capability)
Emissions Reduction (tpy)	123.6	
% Reduction	87.5%	
Cost: $/yr-ton	$ 4,368	

***Targa Calcs_Engine 8 -C08**

Baseline NOx Emissions (tpy)	38.96	(average of 2016-18 Emissions Inventory AEIR)
Emissions with Clean Burn (tpy)	1.32	(based on 2g/hp-hr capability)
Emissions Reduction (tpy)	37.6	
% Reduction	96.6%	
Cost: $/yr-ton	$ 14,344	Engine shutdonw

***Engine 9 -C09**

Baseline NOx Emissions (tpy)	38.96	(average of 2016-18 Emissions Inventory AEIR)
Emissions with Clean Burn (tpy)	1.32	(based on 2g/hp-hr capability)
Emissions Reduction (tpy)	37.6	
% Reduction	96.6%	
Cost: $/yr-ton	$ 14,344	

***Engine 10 -C10**

Baseline NOx Emissions (tpy)	24.15	(average of 2016-18 Emissions Inventory AEIR)
Emissions with Clean Burn (tpy)	1.77	(based on 2g/hp-hr capability)
Emissions Reduction (tpy)	22.4	
% Reduction	92.7%	
Cost: $/yr-ton	$ 24,114	

***Engine 11 -C11**

Baseline NOx Emissions (tpy)	38.75	(average of 2016-18 Emissions Inventory AEIR)
Emissions with Clean Burn (tpy)	1.77	(based on 2g/hp-hr capability)
Emissions Reduction (tpy)	37.0	
% Reduction	95.4%	
Cost: $/yr-ton	$ 14,596	

***Engine 12 -C12**

Baseline NOx Emissions (tpy)	51.66	(average of 2016-18 Emissions Inventory AEIR)
Emissions with Clean Burn (tpy)	1.77	(based on 2g/hp-hr capability)
Emissions Reduction (tpy)	49.9	
% Reduction	96.6%	
Cost: $/yr-ton	$ 10,818	

Engine 13 -C13

Baseline NOx Emissions (tpy)	255.57	(average of 2016-18 Emissions Inventory AEIR)
Emissions with Clean Burn (tpy)	35.69	(based on 2g/hp-hr capability)
Emissions Reduction (tpy)	223.4	
% Reduction	87.4%	
Cost: $/yr-ton	$ 2,416	

*low operating hours consider permit condition to restrict hours or install Clean Burn.

From:	Roberts, Melanie A.
To:	Baca, Michael, ENV; Jones, Mark, ENV; Olson, Kirby, ENV
Cc:	Grygar, Bill W.; Klein, Cynthia S.; Reynolds, Sylwia A.
Subject:	[EXTERNAL] Targa Regional Haze - Revised Cost Estimates
Date:	Friday, August 4, 2023 11:00:17 AM

CAUTION: This email originated outside of our organization. Exercise caution prior to clicking on links or opening attachments.

Thank you for allowing Targa to provide updated information on our previously submitted Four Factor Analyses for our Eunice, Monument, and Saunders Gas Plants. Our updates include equipment operational status changes and updated cost information, including vendor estimates as well as updates to our expected operation and maintenance costs. Vendor cost estimates have been included in a separate confidential submittal.

No changes were made to the Saunders Plant estimates. Targa continues to evaluate the long-term status of this plant. We don't have a schedule for when a final determination will be made.

Electrical Power Updates

Targa has evaluated the cost of adding additional power to the Eunice Gas Plant and has received cost estimates for upgrading the existing substation. The most recent cost estimate was for $7.8 MM in 2022 without any contingency. Our previous estimate was $3 MM. This is a huge increase in costs from what we had previously estimated and is based on actual quotes for expanding the Clark Substation located at Eunice Gas Plant. Targa has included price quotes for some of the equipment needed and a summary of the estimated costs. See confidential submittal for details of the cost estimate.

Other Cost Updates

Targa has made some operational changes to the plants since our last submittal. Eunice Gas Plant has permanently shutdown engines C-8 (previously disclosed), C-9, C-10, C-11, C-12, and C-13. These engines have been blinded off from the headers and can be removed from the air permits. The other engines subject to the 4FA at Eunice (C-01, C-02, C-03, C-04, C-05, C-06. C-07) are subject to NMAC 20.2.50 emission limitations of 3 g/hp-hr and are required to be in compliance by January 1, 2029, based on Targa's current engine inventory and percentage of engines already meeting the standard. At the Monument Plant, we do not have any recent changes to include. Only engine C-28 is subject to the emission limitations of NMAC 20.2.50. The other engines are below the 1,000 hp threshold for applicability.

Targa continues to evaluate the Alternative Compliance Plan (ACP) option in 20.2.50.113.B(10) for engines subject to the emission limitations in 20.2.50.113. Targa intends to submit an ACP for one or more engines at Eunice and/or Monument. A final decision has not yet been made on which engines to apply for the alternative standards. We continue to work to make a determination on which and how many engines we would submit this request for.

Additionally, Targa received updated cost estimates for upgrading the boilers based on the different control technology.

Targa has received updated cost estimates for the following controls or engine replacements:

- Clean-burn technology cost for controls and installation on engines,
- Electric driven compressor,
- Natural gas fired compressor, and
- Additional control modifications for the boilers.

See confidential submittal for details of the cost estimates. These will be sent in a separate email.

Thank you,

Melanie Roberts
Director – Sustainability
TARGA
713.584.1422 (office)

713.309.5869 (mobile)

This email (including any attachments and accompanying emails) may contain proprietary and confidential information. If you are not the intended recipient, please telephone the sender and immediately delete this e-mail (including any attachments and accompanying emails). Please do not replicate, disclose, distribute, forward, or retain this e-mail or any part of this email. Thank you.

Confidential Submittal Omitted

D.13 Tri-State Generation & Transmission Association

Supporting documentation for Tri-State Generation & Transmission Association is provided below. Facility-specific documentation is provided first, followed by documentation pertaining to multiple facilities and/or the owner/operator. The following documents are included in this section (in reading order):

- Prewitt Escalante Generating Station:
    - Facility Closure Notification Letter (3/18/2020)
    - Application for Technical Revision to NSR Permit (7/27/2020)
    - Main Boiler Shutdown Notice (9/14/2020)
    - Administrative Permit Revision (9/28/2020)
    - Permit Closure Letter (10/5/2020)
    - Notice of Transfer of Ownership to McKinley Paper Company (1/28/2021)

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
HEADQUARTERS: P.O. BOX 33695 DENVER, COLORADO 80233-0695 303-452-6111

March 18, 2020

Liz Bisbey-Kuehn
Chief, Air Quality Bureau
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

Re: Tri-State Generation and Transmission Association, Inc. Escalante Generating Station Closure

Dear Ms. Bisbey-Kuehn:

Tri-State Generation and Transmission Association, Inc. (Tri-State) owns and operates the Prewitt Escalante Generating Station (PEGS) in Prewitt, New Mexico. In a letter dated July 18, 2019, the New Mexico Environment Department (NMED) requested that Tri-State conduct a regional haze reasonable progress four-factor analysis for PEGS to comply with EPA's regional haze rule. Tri-State provided that analysis to NMED on December 6, 2019. On January 8, 2020, the Tri-State Board of Directors voted to close PEGS by no later than December 31, 2020.

Tri-State has been engaged with members of the local community in and around Prewitt and those near PEGS as it plans for closure of the facility. Tri-State is committed to supporting our employees and the communities we operate in that are affected by the transition. Tri-State is working with the local community to ease the impact of facility closure, as much as possible. Among other efforts, Tri-State is discussing options with the McKinley Paper Company, located adjacent to PEGS, to continue supplying steam to McKinley Paper through the ongoing operation of the PEGS auxiliary boiler. To date, no decisions have been made about this or other options and discussions are on-going.

Since the PEGS main, coal-fired boiler will not be operating beyond 2020, the Air Quality Bureau and Tri-State have agreed that it would not be appropriate or necessary for further analysis of PEGS under the regional haze rule. In the context of reasonable progress goals under regional haze, the "remaining useful life" referred to in 40 CFR 308(d)(1)(i)(A) will conclude for PEGS in 2020, prior to NMED's proposal of a State Implementation Plan in 2021.

Tri-State appreciates the opportunity to have worked with NMED and the Air Quality Bureau on the development of the reasonable progress four-factor analysis prescribed by the regional haze rule. Should you or your staff have any questions or need additional information please contact Doug Lempke of our staff at 303-254-3590.

Sincerely,

Barbara A. Walz
Senior Vice President
Policy & Compliance
Chief Compliance Officer

BAW:DAL:der

CC: Kerwin Singleton, NMED
Mark Jones, NMED
File: P3 – 3.6(5)

Received
JUL 29 2020
Air Quality Bureau

MONTROSE
AIR QUALITY SERVICES

July 27, 2020

New Mexico Environment Department
Air Quality Bureau
Permits Section
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87507-3313

Subject: NSR Technical Revision Permit Application for Permit #PSD-0285-R4, Prewitt Escalante Generating Station (PEGS)

To Whom it May Concern:

Attached please find two (2) hardcopies and two (2) electronic (CD) copies of the 20.2.72 NMAC Technical Permit Application for Tri-State Generation and Transmission Association, Inc (Tri-State) Prewitt Escalante Generating Station (PEGS). This letter is attached to the application copy that has the original notarized signature page (Section 22), along with an application submittal fee of $500.

PEGS is a single unit coal-fired electric generating station owned and operated by Tri-State. With this technical revision permit application, Tri-State is permanently shutting down the coal-fired boiler, associated coal and limestone handling equipment, and the cooling tower on or before December 31, 2020. Additionally, Tri-State will be transferring ownership and operation of the existing auxiliary boiler and water treatment plant to McKinley Paper Company's Prewitt Mill. Transfer of ownership of the existing auxiliary boiler and water treatment plant to McKinley Paper Company's Prewitt Mill is scheduled for September 30, 2020. Tri-State will continue to operate the existing auxiliary boiler and water treatment plant under the revised PEGS permit until McKinley Paper Company is issued a minor NSR permit.

Please let me know if you have any questions or need additional information.

Sincerely,

Paul Wade

Paul Wade
Sr. Project Manager
Montrose Air Quality Services, LLC

Cc: Dan Salgado, Tri-State

Montrose Air Quality Services, LLC
3500 Comanche Road NE Suite G
Albuquerque, NM 87107-4546

T: 505.830.9680 ext. 6
F: 505.830.9678
Pwade@montrose-env.com
www.montrose-env.com

AIR QUALITY PERMIT #PSD-NM-285-M4-R1
TECHNICAL REVISION APPLICATION

PREPARED FOR

TRI-STATE Generation and Transmission Association, Inc.

A Touchstone Energy® Cooperative

PREWITT ESCALANTE GENERATING STATION
Prewitt, New Mexico

Dated July 23, 2020

Prepared by

Montrose Air Quality Services, LLC

MONTROSE AIR QUALITY SERVICES

Table 2-A: Regulated Emission Sources

Unit and stack numbering must correspond throughout the application package. If applying for a NOI under 20.2.73 NMAC, equipment exemptions under 2.72.202 NMAC do not apply.

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufacturer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] / Date of Construction/ Reconstruction[2]	Controlled by Unit # / Emissions vented to Stack #	Source Classification Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
S1,2,3,4,6, 8,9 (E1)	Vehicle Travel on Paved Roads	NA	NA	NA	NA	NA	NA NA	1 NA	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S10,11,12, 14,18,20 (E10)	Vehicle Travel on Unpaved Roads	NA	NA	NA	NA	NA	NA NA	10 NA	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S13,17,19, 21 (E13)	Vehicle Travel on Haul Roads	NA	NA	NA	NA	NA	NA NA	13 NA	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S22 (E22)	Train Unloading	Heyl & Patterson	NA	NA	3,500 tph	1,203,000 tpy	1984 1984	22 NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S24 (E24)	Transfer Pt. (Conv 1 to Conv 2)	NA	NA	NA	3,500 tph	1,203,000 tpy	2005 2005	24 NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S26 (E26)	Transfer Pt.(Conv 2 to Stacker)	B.L. Monague	NA	NA	3,500 tph	1,203,000 tpy	1984 1984	26 NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S27,28 (E27)	Coal Pile Wind Erosion	NA	NA	NA	NA	NA	NA NA	NA NA	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S29 (E29)	Coal Pile Maintenance	NA	NA	NA	NA	1296 hrs/yr	NA NA	NA NA	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S30 (E30)	Coal Pile Reclaimer Transfer Point	NA	NA	NA	500 tph	1,203,000 tpy	2005 2005	30 NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S31 (E30)	Coal Transfer (drop to Reclaimer and Conv 6A,B)	NA	NA	NA	500 tph	1,203,000 tpy	2005 1984	30 NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S33 (E32)	Coal Crusher	American Pulverizer	WS-58BG-DC	NA	500 tph	1,203,000 tpy	1984 1984	32 NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S35 (E34)	Transfer Pt (Conv 7A,7B to 8A,8B)	NA	NA	NA	500 tph	1,203,000 tpy	2005 2005	34 NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S37 (E34)	Transfer Pt. (Conn 8A&B to bunkers)	NA	NA	NA	500 tph	1,203,000 tpy	2005 2005	34 NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufacturer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] / Date of Construction/ Reconstruction[2]	Controlled by Unit # / Emissions vented to Stack #	Source Classification Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
S38 (E35)	TP Coal Bunkers to Weigh Belt	NA	NA	NA	500 tph	1,203,000 tpy	1984 1984	35 NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S40 (E35)	TP Weigh belt to pulverizers	NA	NA	NA	500 tph	1,203,000 tpy	1984 1984	35 NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S41 (E35)	Pulverizers	Combustion Engineering	863	NA	1,203,000 tpy	1,203,000 tpy	1984 1984	35 NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S47 (E38)	Limestone Truck Unloading	NA	NA	NA	69,000 tpy	69,000 tpy	NA NA	NA NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S48 (E39)	Limestone Pile Wind Erosion	NA	NA	NA	NA	NA	NA NA	NA NA	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S49 (E41)	Limestone Pile Maintenance	NA	NA	NA	NA	260 hrs/yr	NA NA	NA NA	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S51A, S52A or S52B (E42)	Limestone Transfer Pt(reclaimer to conv L2)	NA	NA	NA	600 tph	69,000 tpy	1984 1984	42 42	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S51B (E43)	Loader Limestone Pile to Limestone Hopper	NA	NA	NA	300 tph	69,000 tpy	1984 1984	NA NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S56 (E47)	Limestone Transfer Pt. (Conv L2 to L3)	NA	NA	NA	300 tph	69,000 tpy	1984 1984	45 45	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S54 (E45)	Limestone Transfer Pt. (Conv L3 to L4)	NA	NA	NA	300 tph	69,000 tpy	1984 1984	NA NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S58 (E49)	Limestone Transfer Pt. (Conv L4 to Silos)	Combustion Engineering (silo)	NA	NA	300 tph	69,000 tpy	1984 1984	49 49	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S59, 60, 61, 69, 85 (E50)	Limestone Process Fugitives (Transfer Pt, ball mills, Conv S1)	Mine and Smelter (ball mills)	NA	NA	7.9 tph	69,000 tpy	1984 1984	50 NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S79 (E63)	Intermediate Pile Wind Erosion	NA	NA	NA	NA	NA	NA NA	NA NA	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufacturer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] / Date of Construction/ Reconstruction[2]	Controlled by Unit # / Emissions vented to Stack #	Source Classification Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
S80 (E63)	Area Around Intermediate Pile Wind Erosion	NA	NA	NA	NA	NA	NA NA	NA NA	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S81 (E65)	Intermediate Pile Maintenance	NA	NA	NA	NA	850 hrs/yr	NA NA	NA NA	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S82 (E65)	Sludge /Ash Truck Loading	NA	NA	NA	NA	331,940 tpy	NA NA	NA NA	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S83 (E67)	Fly Ash Silo (loading)	Allen-Sherman-Hoff (silo)	NA	NA	77,900 ft3 (silo volume)	202200 tpy (thorughput)	1984 1984	67 67	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S84a (E67a)	Existing Fly Ash Loadout (sold fly ash loading to trucks)	Midwest International Standards Product	MVL37T/388	NA	23 tons/hr 90,000 tons/yr	0 to 90,000 tpy	2001 2002	69a 69a	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S84b (E67b)	Fly Ash Loadout (sold fly ash loading to trucks)	Industrial Accessores Company	TBD	TBD	23 tons/hr 150,000 tons/yr	0 to 150,000 tpy	2016 2016	69b 69b	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S86,87, 88, 89, 90, 91(E68)	Landfill Pile (truck unloading, erosion, maintenance)	NA	NA	NA	NA	331,940 tpy	NA NA	NA NA	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S92 (E74)	Cooling Tower Drift	Research Cottrell	NA	NA	95,000 gpm	95,000 gpm	1984 1984	NA 74	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S94 (E75)	Soda Ash Silo Loading	NA	NA	NA	25 TPH	3,203 TPY	1984 1984	94 94	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S95 (E75)	Soda Ash Silo Unloading	NA	NA	NA	3,203 TPY	3,203 TPY	1984 1984	95 NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S96 (E76)	Lime Silo Loading	NA	NA	NA	25 TPH	2,212 TPY	1984 1984	96 96	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S97 (E76)	Lime Silo Unloading	NA	NA	NA	2,212 TPY	2,212 TPY	1984 1984	97 NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufacturer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] / Date of Construction/ Reconstruction[2]	Controlled by Unit # / Emissions vented to Stack #	Source Classification Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
S111 (E79)	Coal Fired Boiler	Combustion Engineering	NA	NA	2471 MMBtu/ hr - 1,203,000 tpy coal	2471 MMBtu/ hr - 1,203,000 tpy coal	1984 / 1984	79 / 79	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S112 (E80)	Auxiliary Boiler	ABCO	Fired D-Type	NA	190 MMBtu/hr	190 MMBtu/hr	1993 / 1993	80 / 80	10200602	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S113 (E81)	Plant Heating Boiler	Henry Voight Machine Co.	NA	DT-113-85	99 MMBtu/hr	99 MM Btu/hr	1984 / 1984	81 / 81	10200603	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S126 (E126)	Unleaded Gasoline Tank (WF-UNLD)	NA	NA	NA	500 Gallons	500 Gallons	1984 / 1984	NA / NA	40301008	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S127 (E127)	Unleaded Gasoline Tank (UNLD)	NA	NA	NA	1,288 Gallons	1,288 Gallons	1984 / 1984	NA / NA	40301008	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S150 (E150)	T.P Bottom Ash Conveyor S-4 to Waste Pile	NA	NA	NA	500 tph	500 tph	2008 / 1984	NA / NA	10100201	☐ Existing (unchanged) X To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
S151 (E151)	Emergency Fire Pump	Detroit Diesel	DDFP-06AT7006	6A-420213	357 hp	357 hp	1981 / 1984	NA / NA	10100201	X Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		

Section 3

Application Summary

The **Application Summary** shall include a brief description of the facility and its process, the type of permit application, the applicable regulation (i.e. 20.2.72.200.A.X, or 20.2.73 NMAC) under which the application is being submitted, and any air quality permit numbers associated with this site. If this facility is to be collocated with another facility, provide details of the other facility including permit number(s). In case of a revision or modification to a facility, provide the lowest level regulatory citation (i.e. 20.2.72.219.B.1.d NMAC) under which the revision or modification is being requested. Also describe the proposed changes from the original permit, how the proposed modification will affect the facility's operations and emissions, de-bottlenecking impacts, and changes to the facility's major/minor status (both PSD & Title V).

The **Process Summary** shall include a brief description of the facility and its processes.

Startup, Shutdown, and Maintenance (SSM) routine or predictable emissions: Provide an overview of how SSM emissions are accounted for in this application. Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (http://www.env.nm.gov/aqb/permit/app_form.html) for more detailed instructions on SSM emissions.

The Prewitt Escalante Generating Station (PEGS) is a nominal 273 megawatt single unit coal-fired electric generating station owned and operated by Tri-State Generation and Transmission Association, Inc (Tri-State). PEGS is located at UTM Zone 12, UTM Easting 764.96 km, UTM Northing 3922.88 km, NAD 83, in Township 14N, Range 12W, Sections 22-27, 4 miles north of Prewitt, New Mexico in McKinley County (see Figure 8-2). PEGS operates under Permit #PSD-NM-285-M4R1 issued July 24, 2016 and Title V Operating Permit #P012-R3 issued February 24, 2017.

Tri-State Generation and Transmission Association, Inc. (Tri-State) is submitting a technical revision to Permit #PSD-0285-M4R1 per 20.2.72.219.B.1.a NMAC for Prewitt Escalante Generating Station (PEGS). Tri-State is permanently shutting down the coal-fired boiler, associated coal and limestone handling equipment, and the cooling tower after all existing coal stored at the site is combusted. Additionally, Tri-State will be transferring ownership and operation of the existing auxiliary boiler and water treatment plant to McKinley Paper Company's Prewitt Mill. Transfer of ownership of the existing auxiliary boiler and water treatment plant to McKinley Paper Company's Prewitt Mill is scheduled for September 30, 2020. Tri-State will continue to operate the existing auxiliary boiler and water treatment plant under the revised PEGS permit until McKinley Paper Company is issued a minor NSR permit (see the agreement letter between Tri-State and McKinley Paper Company at the end of this section). McKinley Paper Company submitted their 20.2.72 NMAC minor NSR permit application on July 15, 2020.

The modification of this permit will occur in two permitting phases. Phase 1 includes the shutdown of the coal-fired boiler, associated coal and limestone handling equipment, and the cooling tower after all existing coal stored at the site is combusted. Phase 2 includes the transfer of operation of the existing auxiliary boiler and water treatment plant to McKinley Paper Company, which will occur after the new 20.2.72 NMAC minor NSR permit has been issued for the Prewitt Mill.

Table 3-1 lists the present emission units permitted under Permit #PSD-NM-285-M4R1. Column 3 – 5 presents each emission sources status through Phases 1 and 2. Column 3 lists the emission units that will remain after Phase 2 of this technical permit revision. Column 4 lists the emission units that will be removed during Phase 1 of this technical permit revision. Column 5 lists the emission units that will be removed during Phase 2 of this technical permit revision.

TABLE 3-1: List of Existing Equipment and Status after Phase 1 and Phase 2

Unit No.	Description	Remain	Phase 1	Phase 2
E1	Vehicle Travel on Paved Roads (S1-4, 6, 8, 9)	X		
E10	Vehicle Travel on Unpaved Roads (S10-12, 14, 18, 20)	X		
E13	Vehicle Travel on Haul Roads (S13, 17, 19, 21)	X		
E22	Train Unloading (S22)		X	
E24	Transfer Pt. (Conv 1 to Conv 2) (S24)		X	
E26	Transfer Pt.(Conv 2 to Stacker) (S26)		X	
E27	Coal Pile Wind Erosion (S27, 28)	X		
E29	Coal Pile Maintenance (S29)	X		
E30	Coal Transfer (Coal Pile Reclaimer Transfer Point, drop to Reclaimer and Conv 6A,B) (S30, 31)		X	
E32	Coal Crusher (S33)		X	
E34	Transfer Pt (Conv 7A,7B to 8A,8B to bunkers) (S35, 37)		X	
E35	TP Coal Bunkers (S38) to Weigh Belt(S40) to pulverizers (S41)		X	
E38	Limestone Truck Unloading(S47)		X	
E39	Limestone Pile Wind Erosion(S48)	X		
E41	Limestone Pile Maintenance (S49, S50)	X		
E42	Limestone Transfer Pt(reclaimer to conv L2)(S51A, S52A or S52B)		X	
E43	Loader Limestone Pile to Limestone Hopper(S51B)		X	
E45	Limestone Transfer Pt. (Conv L2 to L3)(S54)		X	
E47	Limestone Transfer Pt. (Conv L3 to L4)(S56)		X	
E49	Limestone Transfer Pt. (Conv L4 to Silos)(S58)		X	
E50	Limestone Process Fugitives (Transfer Pt, ball mills, Conv S1)(S59, 60, 61, 69, 85)		X	
E63	Intermediate Pile Wind Erosion (S79) and Area around Intermediate Pile Wind Erosion (S80)	X		
E65	Intermediate Pile Maintenance (S81) and Sludge/Ash Truck Loading (S82)	X		
E67	Fly Ash Silo Loading (S83)	X		
E67a	Existing Fly Ash Loadout (sold fly ash loading to trucks) (S84a)	X		
E67b	Fly Ash Loadout (sold fly ash loading to trucks) (S84b)	X		
E68	Landfill Pile Operation (truck unloading, erosion, maintenance) (S86-S91)	X		
E74	Cooling Tower Drift (S92)		X	
E75	Soda Ash Silo Loading (S94) and Unloading (S95)			X
E76	Lime Silo Loading (S96) and Unloading (S97)			X
E79	Main Boiler, Coal Fired (S111)		X	
E80	Auxiliary Boiler, NG Fired (S112)			X
E81	Plant Heating Boiler, NG Fired (S113)	X		
E126	Unleaded Gasoline Tank (WF-UNLD) (S126)		X	
E127	Unleaded Gasoline Tank (UNLD) (S127)	X		
E150	T.P Bottom Ash Conveyor S-4 to Waste Pile (S150)		X	
E151	Emergency Fire Pump Engine (S151)	X		

The change in pollutant emission rates for this technical revision after Phase 1 to Permit PSD-NM-285-M4R1 is summarized in Table 3-2.

TABLE 3-2: Facility Emission Limits after Phase 1

Pollutant	Present Permit Emissions TPY	After Phase 1 Facility Emissions TPY	Reduction in Emissions After to Phase 1 TPY
NOx	4,919	50	4,869
CO	749	67	682
VOC	40	4.3	35.7
SO_2	2,165	0.5	2,164.5
PM	347	103	244
PM_{10}	254	35	219
$PM_{2.5}$	227	12	215
HAPs	32	1.4	30.6
State TAPs	<0.5	<0.1	<0.4
Fluorides	10.9	0	10.9
Lead	0.25	<0.001	0.25
Sulfur compounds	1.1	0	1.1
GHG	2,363,891	87,907	2,275,984

The change in pollutant emission rates for this technical revision after Phase 2 to Permit PSD-NM-285-M4R1 is summarized in Table 3-3.

TABLE 3-3: Facility Emission Limits after Phase 2

Pollutant	Present Permit Emissions TPY	After Phase 2 Facility Emissions TPY	Reduction in Emissions After to Phase 2 TPY
NOx	4,919	12	4,907
CO	749	9.7	739.3
VOC	40	0.9	39.1
SO_2	2,165	0.08	2,164.9
PM	347	98	249
PM_{10}	254	31	223
$PM_{2.5}$	227	7.7	219.3
HAPs	32	0.2	31.8
State TAPs	<0.5	<0.1	<0.4
Fluorides	10.9	0	10.9
Lead	0.25	<0.001	0.25
Sulfur compounds	1.1	0	1.1
GHG	2,363,891	12,684	2,351,207

Remainder of Application Omitted for Brevity

DocuSign Envelope ID: 1CF32681-0B31-47AE-9491-946FA9FDF97F

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
HEADQUARTERS: P.O. BOX 33695 DENVER, COLORADO 80233-0695 303-452-6111

September 14, 2020

Submitted via email Joseph Kimbrell (joseph.kimbrell@state.nm.us)

Joseph Kimbrell
New Mexico Environment Department, AQB
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505-1816

RE: Tri-State Generation and Transmission Association, Inc.
Compliance Progress Report – NSR Permit No.- 0285-M4R2

Dear Mr. Kimbrell:

Tri-State Generation and Transmission Association, Inc. (Tri-State) is notifying NMED through this letter the cessation of E79 – Main Boiler Unit at the Prewitt Escalante Generating Station, as per condition A112.E in the NSR Permit 0285-M4R2. E79 –Main Boiler Unit ceased operations on August 31, 2020, ahead of its December 31, 2020 deadline. Phase 2 is still on track and should be completed when Air Quality Permit 8889 is issued to McKinley Paper Company's Paper Mill.

Tri-State will submit a NSR significant permit modification application within 90 days of the cessation of E79 – Main Boiler Unit (November 29, 2020) as required in condition A112.C(3), to remove all conditions from the permit that no longer apply and to add new conditions for the remaining plant heating boiler, road fugitives and other items.

Please contact Jennifer McCurdy or me at 303-452-6111 if you have questions.

Sincerely,

DocuSigned by:
Barbara Walz
A5D5C24494CD4A7...

Barbara A. Walz
Senior Vice President
Policy and Compliance/
Chief Compliance Officer

BAW:JM:der

Enclosures

File – G23-11.3(1)l-1

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
HEADQUARTERS: P.O. BOX 33695 DENVER, COLORADO 80233-0695 303-452-6111

September 28, 2020

New Mexico Environment Department
Air Quality Bureau
Permit Programs Manager
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505-1816

RE: Tri-State Generation and Transmission Association, Inc.
Prewitt Escalante Generating Station – Cancellation of Title V Permit No: P012-R3 and Acid Rain Permit No: P012A-R3

Dear Sir or Madam:

Tri-State Generation and Transmission Association, Inc. (Tri-State) is requesting the cancellation of Prewitt Escalante Generating Station's (PEGS) Title V permit No: P012-R3 and its Acid Rain permit No: P012A-R3 as per the shutdown schedule in the NSR permit No: 0285-M4R2, condition A112. The Main Boiler – E79 ceased operation on August 31, 2020 and is permanently retired, thus PEGS is no longer a major source and is not subject to the Acid Rain regulations. Enclosed are the cancellation forms for the Title V permit and Acid Rain permit for your approval. As well as, EPA's retired unit exemption form, sent to EPA and confirmation that the unit has been retired in CAMD.

Please contact Jennifer McCurdy or me at 303-452-6111 if you have any questions regarding this submittal.

Sincerely,

Barbara A. Walz
Senior Vice President
Policy and Compliance/
Chief Compliance Officer

BAW:JM:

Enclosure

cc: Joseph Kimbrell (joseph.kimbrell@state.nm.us)

G23-11.3(1)h-1

RECEIVED
OCT 02 2020
Air Quality Bureau

Permitting Administrative Multi-Form

Use for NSR administrative permit revisions (including GCPs), TV administrative amendments, TV responsible official notifications, and other submittals required by a permit condition. Refer to Section 4 for instructions, acronyms, and mailing addresses.

For Department use only:		For Department use only:
Reviewed by:		Received Date RECEIVED
Permit revision number:		OCT 02 2020
Date:		Air Quality Bureau
☐ Approved ☐ Completed ☐ Denied		

Section 1: General Information – Required for All Submittals

1	Facility Name: Prewitt Escalante Generating Station		
2	Preparer/Consultant Name: Jennifer McCurdy	Title: Sr. Env. Engineer	
3	Email: jmccurdy@tristategt.org	Phone: 303-452-6111 ext. 3237	
4	Address: 1100 W 116th Ave, Westminster, CO 80234		
5	Air Permit Contact: Jennifer McCurdy	Title: Sr. Env. Engineer	
6	Email: jmccurdy@tristategt.org	Phone: 303-452-6111 ext. 3237	
7	Address: 1100 W 116th Ave, Westminster, CO 80234		
8	Check all boxes below for which this submittal applies:	AI #: 911	Permit #: P012-R3 & P012A-R3

☐ NSR Construction Permit (20.2.72 NMAC) X TV Operating Permit (20.2.70 NMAC)	☐ NOI (20.2.73 NMAC) (Sections 2-B, 2-D) ☐ Notice of Exemption (20.2.72.202.B NMAC) (Section 2-F)	☐ PSD Permit (20.2.74 NMAC) ☐ Nonattainment Permit (20.2.79 NMAC)

Section 2: Details of Submittal

Only print and submit the pages necessary for your submittal. Print double sided head-to-toe, flip on short end (tablet). The Permit Section responds to all TV Administrative amendments and responds only to denials of NSR administrative revisions. Courier proof of delivery is required if you want confirmation that the Department received this submittal. Check the box(es) applicable to this submittal:

☐ 2-A(i) & 2-A(ii): Identical Engine or Turbine Replacements

☐ 2-B: Owner, Operator, and Name Changes to NOIs or Construction Permits

☐ 2-C: Ownership or Operational Control Changes for Title V Permits

☒ 2-D: Closing a Facility or Removing Units from a Permit

☐ 2-E: Correct Typographical Error

☐ 2-F: Reporting Exempt Equipment for Minor Construction Permits or for No Permit Required (NPR) Facilities

☐ 2-G: Add Minor NSR Exempt Equipment to Construction Permits for PSD or Nonattainment Sources

☐ 2-H: Title V Responsible Official Designations

☒ 2-I: Submittals to the Permit Programs Manager

Section 3: Certification – Required for All Changes

Section 4: Form Instructions

Section 2-D: Closing a Facility or Removing Units from a Permit

(Administrative Revision)

Check the appropriate boxes and provide complete information in the table. Closing the permit does not relieve the permittee from any outstanding permit fees.

If any of the units being removed are emission control equipment explain how a permit, federal regulation, or state regulation will not be violated by removal of the control equipment.

☐ Cease operations of the entire facility and cancel the construction permit (20.2.72.219.A(1)(c) NMAC).

Date the facility ceased operating:

☐ Retire an emissions unit and remove it from the construction permit (20.2.72.219.A(1)(c) NMAC).

Date unit(s) retired:
List all retired unit numbers to be removed from the permit:

☐ Cancel a construction permit for a facility or remove an emissions unit that has not and will not be constructed (20.2.72.219.A(1)(d) NMAC).

☐ Facility (plant) will not be constructed, or	☐ The following units will not be constructed and should be removed from the permit:

☐ Retire an emissions unit and remove it from the TV permit (20.2.70.404.A(1)(c) NMAC).

Date unit(s) retired:
List all retired unit numbers to be removed from the permit:

☒ Voluntary Discontinuation of the TV permit (20.2.70.400.I NMAC).

Date the TV permit was no longer required: August 31, 2020
Explanation: E79 Main Boiler ceased operation on August 31, 2020, and is permanently retired, therefore PEGS is no longer a major facility under Title V.

☒ Cancel a construction permit that is no longer required.

Explanation: E79 Main Boiler ceased operation on August 31, 2020 and is permanently retired. The facility is no longer subject to the Acid Rain regulations and Tri-State would like to cancel the Acid Rain Permit No: P012A-R3. See NSR permit No: 0285-M4R2 for Specific Condition A112 for the shutdown schedule.

☐ Removal of minor NSR exempt equipment.

Explanation:

Section 2-I: Submittals to the Permit Programs Manager

As Required by Permit Conditions or Other Regulations

(Notification or Administrative Revision)

Use this section for submittals to the Permit Programs Manager of notifications or administrative permit revisions/amendments required by permit conditions that do not correspond with any other section of this submittal form. Explain your request, including any permit condition or regulatory citations that requires this submittal, and include the necessary attachments.

For example:

- Your permit has a condition that allows a specific change through an administrative revision.
- Your permit has a condition that requires submittal of information to the attention of the Permit Programs Manager such as a good combustion practice plan.
- A condition that allows a deadline to be extended through an administrative permit revision.
- Notification per General Condition B116 Short Term Engine Replacement
- Notification of TV Operating Permit Section 502(b)(10) Changes (20.2.70.302.H(1) NMAC).
  - Before submitting a 502(b)(10) change request, contact the Major Source Program Manager or the TV Program Manager to discuss what information should be included in the request to ensure that the request is federally enforceable if enforceable limits are needed to avoid a construction permit application. Visit www.env.nm.gov/air-quality/permitting-section-home-page/ for contact information.
  - If the change must be made immediately, you may send the request by email to one of the managers listed above.

As per NSR permit No: 0285-M4R2, Condition A407 Acid Rain Permit, P0212AR3 (This condition will not be applicable after completion of Phase 1 and the Title IV and V permits have been cancelled).

Phase 1 was completed on August 31, 2020 when E79 Main Boiler ceased operation.

Section 3: Certification – Required for All Applications

Company Name: Tri-State Generation and Transmission Assoc., Inc.

I, Barbara A. Walz, hereby certify that the information and data submitted in this application are true and as accurate as possible, to the best of my knowledge and professional expertise and experience.

Signed this 28TH day of September, 2020, upon my oath or affirmation, before a notary of the State of Colorado.

Barbara A Walz — 9/28/20

Signature[1] — Date

Barbara A. Walz — Sr. VP Policy & Compliance/ Chief Compliance Officer

Printed Name — Title

Scribed and sworn before me on this 28TH day of September, 2020.

My authorization as a notary of the State of Colorado expires on the 22nd day of April, 2024.

Daunice Lynn Kennedy — 9/28/20

Notary's Signature — Date

Daunice Kennedy

Notary's Printed Name

Daunice Lynn Kennedy
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20204014602
MY COMMISSION EXPIRES 4/22/2024

[1] For Title V applications, the signature must be of the Responsible Official as defined in 20.2.70.7.AE NMAC:

New Mexico
Environment Department

525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505-1816
Phone (505) 476-4300
Fax (505) 476-4375
www.env.nm.gov

MICHELLE LUJAN GRISHAM
GOVERNOR

HOWIE C. MORALES
LT. GOVERNOR

JAMES C. KENNEY
CABINET SECRETARY

JENNIFER J. PRUETT
DEPUTY SECRETARY

Air Quality Bureau

October 5, 2020

Sent by Certified Mail
No return receipt

Jennifer McCurdy
Senior Engineer, Environmental Services
Tri-State Generation and Transmission Association, Inc.
PO Box 33695
Denver, CO 80233-0695

Ref: **Air Quality Operating and Acid Rain Permits P012-R3 and P012A-R4**
Prewitt Escalante Generating Station
NSR Permit No. PSD0285-M4R2
Agency Interest No. 911 - PRT20200001
AIRS No: 350310032

Dear Ms. McCurdy:

The Air Quality Bureau is in receipt of Tri-State Generation and Transmission Association, Inc.'s September 28, 2020 request to voluntarily discontinue the Prewitt Escalante Generating Station Title V Operating Permit No. P012-R3 and Title IV Acid Rain Permit No. P012A-R4, pursuant to 20.2.70.400.I NMAC. An existing Title V major source may apply for a permit under 20.2.72 NMAC to obtain federally enforceable conditions that restrict the facility's potential to emit to below Title V Major Source thresholds.

The Air Quality Bureau received Tri-State Generation and Transmission Association, Inc.'s NSR Permit application on July 29, 2020 for Prewitt Escalante Generating Station located in Township 14N, Range 12W, Section 25 in McKinley County, New Mexico. Tri-State Generation and Transmission Association, Inc.'s NSR permit 2448-M4R2, with federally enforceable limitations on the potential to emit and schedule shutdown plan, was issued on August 27, 2020.

The Air Quality Bureau has verified that the actions required to reduce the potential to emit of this facility to below Major Source thresholds have been met. Therefore, the Department has cancelled Title V Operating Permit No. P012-R3 and Title IV Acid Rain Permit No. P012A-R4 for the Prewitt Escalante

Generating Station as of September 28, 2020 and Tri-State Generation and Transmission Association, Inc.'s facility will be removed from the list of Title V sources in New Mexico.

If you have any questions, please call Joseph Kimbrell in Santa Fe at 505-476-4347.

Sincerely,

Elizabeth Kuehn
Digitally signed by Elizabeth Kuehn
Date: 2020.10.05 18:27:22 -06'00'
Liz Bisbey-Kuehn
Air Quality Bureau Chief

cc via email: EPA Region VI, 6PD-R, r6airpermits@epa.gov, LeDoux.Erica@epa.gov
Craig S. Hillock, U. S. EPA, Clean Air Markets Division, Hillock.Craig@epa.gov
NMED-AQB Compliance & Enforcement Managers via email:
Allan.Morris@state.nm.us; David.Feather@state.nm.us
ted.schooley@state.nm.us; Melinda.Owens@state.nm.us

Attachment: Approved Permitting Administrative Multi-Form P012R3M1.

McKinley Paper Company Inc.

Via Electronic Mail to: joseph.kimbrell@state.nm.us; melinda.owens@state.nm.us; rhonda.romero@state.nm.us

January 28, 2021

Joe Kimbrell, Permit Engineer
Melinda Owens, Title V Supervisor
Rhonda Romero, NSR Minor Source Manager
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505-1816

Dear Ms. Owens, Ms. Romero and Mr. Kimbrell:

McKinley Paper Company (MPC) is writing to notify the New Mexico Environment Department (NMED) of the just concluded transfer of ownership of the following facilities from Tri-State Generation and Transmission Association (Tri-State) to MPC as of the date of this letter:

- Soda Ash Silo (Regulated Source 8),
- Soda Ash Silo Unloading (Regulated Source 9),
- Lime Silo (Regulated Source 10),
- Lime Silo Unloading (Regulated Source 11), and the
- Auxiliary Steam Boiler (Regulated Source 13)

These regulated units collectively referred to as "Conditional Sources" are all identified in MPC's NSR Minor Source Permit (NSR Permit #8886). Based on the above, Phase II of the Tri-State NSR Minor Source Permit (NSR Permit #0285-M4R2 & 3) has been completed. In addition, all applicable permit requirements relative to the Conditional Sources in MPC's NSR Minor Source Permit (NSR Permit #8886) are now enforceable in the MPC air permit.

Thank you for NMED's assistance in working with MPC. Please let us know if you have any questions.

Respectfully,

Isaac Rosas
McKinley Paper Company

D.14 Xcel Energy

Supporting documentation for Xcel Energy is provided below. Facility-specific documentation is provided first, followed by documentation pertaining to multiple facilities and/or the owner/operator. The following documents are included in this section (in reading order):

- Cunningham Station Power Plant:
    - NMED Final Cost Evaluation
    - Initial Four-Factor Analysis (11/2019)
    - Follow-Up Submittal (2/2020)
    - Follow-Up Submittal (11/2/2020)
    - Follow-Up Submittal (1/25/2021)
    - Follow-Up Submittal (7/18/2023)

NMED Final Cost Evaluation
Xcel Energy - Cunningham Station Power Plant

Facility Information

Xcel - Cunningham Station	**Facility**
Two 1997 simple cycle CTs, 115 MW	**Units**
3 & 4	**Unit IDs**
Water Injection	**Evaluated Pollution Control**
4.0	**NOx reduction (ppmvd)***

*9.18.2020 Letter from Siemens Energy (CBI) states, "The application of FGPWI could reduce NOx emissions for this plant by 3-4 ppmvd..."

Supporting Information

2020	**Calendar year associated with cost estimates**
1400	**Heat Input Capacity (MMBTU/hr)**

Economic Evaluation

Cost Component		Unit 3	Unit 4	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	A CBI Siemens Energy, Inc. (Vendor) estimate included the material scope of supply for a Water Injection (WI) upgrade for Units 3 & 4. Xcel estimated the WI TCI in a 2020 "capital project estimate" that included labor, other costs, contingency and overhead.
Other Direct Capital Costs 1 ($)	ODC	$ -	$ -	-	
Indirect Capital Costs ($)	IDC	$ -	$ -	-	
Total Capital Costs - Direct ($)	TCC	$ -	$ -	-	
Additional Capital ($)	AC	$ -	$ -	-	
Total Capital Investment ($)	TCI	$ 3,663,850	$ 3,663,850	Xcel 11/2/2020 FFA update (CBI)	
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	Xcel did not provide a company-specific rate
Useful Life (yr)	Y	15	15	Xcel initial FFA submittal (11/2019)	Reasonably consistent with other FFAs
Capital Recovery Factor	CRF	0.1133	0.1133	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 415,067	$ 415,067	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 57,764	$ 57,764	Xcel 2/14/2020 FFA update	Most recent estimate provided by Xcel
Other Indirect Annual Costs ($/yr)	OAC	$ 146,554	$ 146,554	EPA Cost Manual, Section 2.6.5.8	4% of TCI
Total Annualized Costs ($/yr)	TAC	$ 619,385	$ 619,385	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	25%	31%	-	Estimated PPM Reduction/Current Emissions Rate (in PPM)
Baseline Actual NOx Emissions (ton/yr)	BAE	94.4	104.3	CY 2023 RATA testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Xcel
Projected Actual Emissions (ton/yr)	PAE	94.4	104.3	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	23.9	32.0	-	PAE x Eff
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 25,967**	**$ 19,329**	-	TAC/ER; Cost estimate provided in September 2020 and thus assumed costs are in 2020$
Price Index	PI	1.34	1.34	-	2024 CEPCI* / 2020 CEPCI *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 34,796**	**$ 25,900**	-	CE1 x PI

NMED Final Cost Evaluation
Xcel Energy - Cunningham Station Power Plant

Facility Information

Xcel - Cunningham Station	**Facility**
Two 1997 simple cycle CTs, 115 MW	**Units**
3 & 4	**Unit IDs**
SCR	**Evaluated Pollution Control**

Supporting Information

2024	**Calendar year associated with cost estimates**
1400	**Heat Input Capacity (MMBTU/hr)**

Economic Evaluation

Cost Component		Unit 3	Unit 4	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 26,358,555	$ 26,358,555	EPA SCR Tool (2024$)	
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	Xcel did not provide a company-specific rate
Useful Life (yr)	Y	20	20	EPA Cost Manual	
Capital Recovery Factor	CRF	0.0981	0.0981	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 2,585,568	$ 2,585,568	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 474,060	$ 536,465	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 4,210	$ 4,210	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 3,063,838	$ 3,126,244	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	90%	90%	EPA SCR Tool	Consistent with EPA and industry documentation
Baseline Actual NOx Emissions (ton/yr)	BAE	94.4	104.3	CY 2023 RATA testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Xcel
Projected Actual Emissions (ton/yr)	PAE	94.4	104.3	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	84.9	93.9	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 36,081**	**$ 33,297**	-	TAC/ER

NMED Final Cost Evaluation
Xcel Energy - Cunningham Station Power Plant

Facility Information

Xcel - Cunningham Station	**Facility**
Two 1997 simple cycle CTs, 115 MW	**Units**
3 & 4	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
9.0	**Post-control Emissions Rate (ppm NOx)***

*Consistent with NMED's emissions standards in the ozone precursor rule ("Part 50") for new NG-fired CT >15,900 hp. Part 50 does not apply to Cunningham Station Power Plant, but value is believed to be a reasonable surrogate.

Supporting Information

2022	**Calendar year associated with cost estimates**
1400	**Heat Input Capacity (MMBTU/hr)**

Economic Evaluation

Cost Component		Unit 3	Unit 4	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC1	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 2 ($)	ODC2	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 99,705,000	$ 99,705,000	U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2023 (AEO2023) Assumptions document - Electricity Market Module	$867/kW (2022$) base overnight cost. The new turbines will need to provide 230 MW to replace Units 3 and 4. The Base cost includes project contingency costs.
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	Xcel did not provide a company-specific rate
Useful Life (yr)	Y	30	30	ERG experience based on discussions with CT manufacturers	
Capital Recovery Factor	CRF	0.0847	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 8,442,146	$ 8,442,146	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 1,376,000	$ 1,806,703	U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2023 (AEO2023) Assumptions document - Electricity Market Module	$5.06/MWh (2022$) variable O&M costs for an Industrial Frame CT. This cost figure does not account for current O&M costs incurred by Xcel.
Other Indirect Annual Costs ($/yr)	OAC	$ -	$ -	-	4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs associated with replacement with an equivalent/like-kind unit
Total Annualized Costs ($/yr)	TAC	$ 9,818,145	$ 10,248,848	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	43%	31%	-	(Current actual emissions rate - Post-control emissions rate)/Current actual emissions rate
Baseline Actual NOx Emissions (ton/yr)	BAE	94.4	104.3	CY 2023 RATA testing and average operating hours (2016-2021)	
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Xcel
Projected Actual Emissions (ton/yr)	PAE	94.4	104.3	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	40.7	32.2	-	PAE x Eff
2022$ Cost Effectiveness ($/ton)"	**CE1**	**$ 241,344**	**$ 318,078**	-	TAC/ER; The EIA Annual Energy Outlook 2023 cost information was provided in 2022$
Price Index	PI	0.98	0.98	-	CEPCI 2024* / CEPCI 2022 *Based on January-September values
2024$ Cost Effectiveness ($/ton)	**CE2**	**$ 236,517**	**$ 311,716**	-	CE1 x PI

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Facility Information

Xcel - Cunningham Station	**Facility**
Two NG-fired boilers Constructed in 1957 and 1965 respectively	**Units**
1 & 2	**Unit IDs**
SCR	**Evaluated Pollution Control**

Supporting Information

2024	**Calendar year associated with cost estimates**
784	**Unit 1 Heat Input Capacity (MMBTU/hr)**
1,951	**Unit 2 Heat Input Capacity (MMBTU/hr)**

Economic Evaluation

Cost Component		Unit 1	Unit 2	Source	Methodology/Note
Purchased equipment costs ($)	PEC	$ -	$ -	-	Included in TCI
Other Direct Capital Costs 1 ($)	ODC	$ -	$ -	-	Included in TCI
Indirect Capital Costs ($)	IDC	$ -	$ -	-	Included in TCI
Total Capital Costs - Direct ($)	TCC	$ -	$ -	-	Included in TCI
Additional Capital ($)	AC	$ -	$ -	-	Included in TCI
Total Capital Investment ($)	TCI	$ 18,081,890	$ 32,704,356	EPA SCR Tool (2024$)	
Interest Rate (%)	R	7.50%	7.50%	Bank prime rate as of December 2024	Xcel did not provide a company-specific rate
Useful Life (yr)	Y	30	30	EPA Cost Manual	
Capital Recovery Factor	CRF	0.0847	0.0847	-	Standard CRF calculation
Annualized Capital Costs ($/yr)	ACC	$ 1,531,016	$ 2,769,118	-	TCI x CRF
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 455,835	$ 1,187,256	EPA SCR Tool (2024$)	Direct Annual Costs
Other Indirect Annual Costs ($/yr)	OAC	$ 3,713	$ 4,590	EPA SCR Tool (2024$)	Administrative Charges
Total Annualized Costs ($/yr)	TAC	$ 1,990,564	$ 3,960,964	-	ACC + OMC + OAC
NOx Control Efficiency (%)	Eff	90%	90%	EPA SCR Tool	Consistent with EPA and industry documentation
Baseline Actual NOx Emissions (ton/yr)	BAE	300.0	868.2	CY 2021 RATA testing and average operating hours (2016-2021)	Xcel did not provide a RATA testing report to NMED for Unit 1. NMED cannot calculate the BAE without this information. Used emissions from Boiler #2 on a lb/MMBtu basis for Boiler #1.
Future Utilization Adjustment (%)	FUA	0%	0%	-	Not requested by Xcel
Projected Actual Emissions (ton/yr)	PAE	300.0	868.2	-	BAE x (1 + FUA)
Estimated Reductions (ton/yr)	ER	270.0	781.4	-	PAE x Eff
2024$ Cost Effectiveness ($/ton)	**CE**	**$ 7,373**	**$ 5,069**	-	TAC/ER

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Xcel Energy - Cunningham Station Power Plant

Unit 1: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	784	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	3,778,560,621	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3815	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.1540	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0154	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 1: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	784	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	6,661,338,506	scf/Year	
Actual Annual fuel consumption (Mactual) =		3,778,560,621	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.567	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4969	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	90.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	108.63	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	269.89	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.15		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,180.81	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	42	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	146	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	19	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	6,600	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	464.14	kW

Unit 1: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$18,081,890	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$455,835 in 2024 dollars
Indirect Annual Costs (IDAC) =	$1,777,546 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$2,233,382 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$90,409 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$51,118 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$230,629 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$83,679 in 2024 dollars
Direct Annual Cost =		$455,835 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,713 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,773,833 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,777,546 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,233,382 per year in 2024 dollars
NOx Removed =	270 tons/year
Cost Effectiveness =	$8,275 per ton of NOx removed in 2024 dollars

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Unit 2: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	1951	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	10,935,818,623	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3815	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.1540	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0154	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Densities of typical SCR reagents:

50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 2: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	1,951	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	16,576,876,819	scf/Year	
Actual Annual fuel consumption (Mactual) =		10,935,818,623	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.660	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5779	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	90.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	270.45	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	781.47	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.15		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	7,915.71	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	105	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	362	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	48	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	16,300	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	1155.01	kW

Unit 2: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$32,704,356	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,187,256 in 2024 dollars
Indirect Annual Costs (IDAC) =	$3,212,888 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$4,400,143 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$163,522 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$148,010 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$667,481 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$208,242 in 2024 dollars
Direct Annual Cost =		$1,187,256 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,590 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$3,208,297 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$3,212,888 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$4,400,143 per year in 2024 dollars
NOx Removed =	781 tons/year
Cost Effectiveness =	$5,631 per ton of NOx removed in 2024 dollars

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Xcel Energy - Cunningham Station Power Plant

Unit 3: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	1400	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	3,211,445,199	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3815	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.0570	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0114	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 3: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	1,400	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	11,895,247,333	scf/Year
Actual Annual fuel consumption (Mactual) =		3,211,445,199	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.270	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	2365	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	63.84	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	75.49	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.15	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	5,015.86	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	25	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	86	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	11	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	3,900	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	828.81	kW

Unit 3: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$26,358,555	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$474,060 in 2024 dollars
Indirect Annual Costs (IDAC) =	$2,589,984 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$3,064,044 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$131,793 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$14,298 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$196,015 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$131,955 in 2024 dollars
Direct Annual Cost =		$474,060 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,210 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,585,774 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,589,984 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,064,044 per year in 2024 dollars
NOx Removed =	75 tons/year
Cost Effectiveness =	$40,588 per ton of NOx removed in 2024 dollars

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Unit 4: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	1400	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	4,216,294,859	scf/Year
Enter the net plant heat input rate (NPHR)	11.38	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3815	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days		
Number of days the boiler operates (t_{plant})	365	days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.0480	lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0096	lb/MMBtu		
Stoichiometric Ratio Factor (SRF)	1.050			

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F	*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.
Base case fuel gas volumetric flow rate factor (Q_{fuel})	UNK	ft^3/min-MMBtu/hour	

Concentration of reagent as stored (C_{stored})	29	percent*	*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*	
Number of days reagent is stored ($t_{storage}$)	14	days	

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024				
CEPCI for 2024	797.6	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.529	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.1000	$/kWh			
Catalyst cost ($CC_{replace}$)	255.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit 4: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	1,400	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	11,895,247,333	scf/Year
Actual Annual fuel consumption (Mactual) =		4,216,294,859	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.14	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.354	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3105	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	53.76	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	83.46	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour
Residence Time	1/V_{space}	#VALUE!	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.15	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	4,999.22	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	21	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	72	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	10	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	3,300	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0981

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	828.81	kW

Unit 4: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$26,358,555	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$536,465 in 2024 dollars
Indirect Annual Costs (IDAC) =	$2,589,984 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$3,126,448 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$131,793 in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$15,808 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$257,347 in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$131,517 in 2024 dollars
Direct Annual Cost =		$536,465 in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,210 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,585,774 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,589,984 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,126,448 per year in 2024 dollars
NOx Removed =	83 tons/year
Cost Effectiveness =	$37,459 per ton of NOx removed in 2024 dollars

REGIONAL HAZE FOUR-FACTOR ANALYSIS

Xcel Energy, Cunningham Station

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1. EXECUTIVE SUMMARY

In the 1977 amendments to the Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

> *(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A).* This is known as a four-factor analysis.
>
> *(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B).* The uniform rate of progress or improvement is sometimes referred to as the glidepath and is part of the state's Long Term Strategy (LTS).

The second implementation planning period (2018-2028) for national regional haze efforts is currently underway. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural or biogenic and manmade or anthropogenic sources of emissions. Using a Photochemical Grid Model (PGM), the Western Region Air Partnership (WRAP), in coordination with the EPA, is tasked with comparing anthropogenic source contributions against natural background concentrations.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for major sources and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I area. From this analysis, 24 facilities were identified by the NMED. On July 18, 2019 the NMED informed Xcel Energy (Xcel), that its Cunningham Station (Cunningham) was identified as one of the sources potentially contributing to regional haze at the CarlsbadCaverns National Park Class I area.

In coordination with guidance provided by WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. The NMED's July 18, 2019 notification letter to Xcel specifies that any equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The NMED also provided additional guidance that only steady-state emissions shall be considered in the four-factor analysis. Therefore,

the emergency generator (Unit EGR1) is not discussed in this report. The equipment at the facility that is subject to the analysis, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant are reported in Table 1.

Table 1. Summary of Equipment and Applicability of the Four-Factor Analysis

Equipment	NO_X Hourly PTE (lb/hr)	NO_X Annual PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
Natural Gas-Fired Boiler (Unit 1)	235.20	1030.00	Yes	2.90	12.90	No
Natural Gas-Fired Boiler (Unit 2)	585.30	2564.00	Yes	7.30	32.20	No
Natural Gas-Fired Turbines – Normal Operation (Units 3 &4)	78.10	170.90	Yes	22.10	55.10	Yes
Natural Gas-Fired Turbines – Augmented Operation (Units 3 &4)	129.00	38.70	Yes	-	-	No

Once the applicability of process equipment and pollutants has been determined, potential retrofit control technologies must be identified. In accordance with 40 CFR 51 Appendix Y and at recommendation of the NMED[1], this is primarily achieved by utilizing the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) data. In order to determine the most relevant and current retrofit controls available, the RBLC is queried for the previous ten years. Summaries of the result of this search are provided and discussed under Section 2 of this report. The facility engineers then reviewed the list of available retrofit technologies and performed a technical feasibility assessment for each control option. The four-factor analysis is then conducted for those controls that are technically feasible.

[1] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

2.1. COMBUSTION TURBINES

As reported in Table 1 Cunningham's two natural gas-fired simple cycle peaking turbines, Units 3 and 4, are NO_x and SO_2.

2.1.1. Combustion Turbine Background

A gas turbine is an internal combustion engine that operates with a rotary, rather than reciprocating, motion and is composed of three primary components: a compressor, a combustor, and a power turbine. The compressor draws in ambient air and compresses it up to 30 times the ambient pressure, then directs it into the combustor where fuel is introduced, ignited, and burned. Exhaust gas from the combustor is then diluted with additional air and sent to the power turbine at temperatures up to 2600 °F. The hot exhaust gas expands in the power turbine section, generating energy in the form of shaft horsepower.[2]

The treatment of the exhaust gases exiting the turbine dictates the cycle designation of these units. The heat content can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).[3] The units at Cunningham are simple cycle turbines.

NO_X is formed via three fundamentally different mechanisms. The principle NO_X formation mechanism, thermal NO_X, arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion. Most thermal NO_X forms in the highest temperature regions of the combustion chamber. The second NO_X formation mechanism, fuel NO_X, arises from the evolution and reaction of fuel bound nitrogen compounds with oxygen. The final NO_X formation mechanism, prompt NO_X, arises from early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The significance of prompt NO_X is negligible in comparison to thermal and fuel NO_X. Fuel NO_X will also be negligible for Cunningham's turbines assessed here, as these combustion turbines fire natural gas, which contains a negligible amount of nitrogen compounds. Therefore, this analysis will focus on thermal NO_X.

The PTE from each turbine referenced from the facility's PSD (0622) and Title V (P080) permits are summarized in Table 1. There are two operational modes associated with these units: with and without power augmentation. NO_x composition of stack gas during normal operations is approximately 15 ppmv, whereas the composition during power augmentation is 25 ppmv. A safety factor is then applied to these emissions to calculate the PTE represented in the permits for these unit.

SO_2 emissions from turbines are generated when sulfur in fuel gas is combusted in the turbine. The PTE for SO_2 is calculated with an assumed conservative fuel gas sulfur content of 5.25 gr S/100 scf. The PTE for these units is calculated based on this fuel sulfur content and is represented in Cunningham's NSR and Title V permits as 22.1 lb/hr/unit.

[2] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"

[3] Ibid.

2.1.2. Potential NO_X Controls for a Combustion Turbine

There are three general methods of controlling NO_X emission from gas turbines; (1) wet controls, which use steam or water injection to reduce combustion temperatures and NO_X formation, (2) dry controls that use advanced combustor design to suppress NO_X formation, and (3) post-combustion, catalytic controls to selectively reduce NO_X.[4]

The retrofit control equipment that was identified for combustion turbines during a comprehensive review of the RBLC, available literature, and manufacturer's input is reported in Table 2. A more detailed table summarizing the RBLC review is provided in Appendix A. A detailed discussion, including a description, the technical feasibility, and the anticipated performance of each control is provided below.

Table 2. Potential Control Equipment for Combustion Turbines

Control Equipment	Technically Feasible	NO_X Control Efficiency
Dry low NO_X	**Currently Installed**	**N/A**
Improved dry low NO_X	**No**	**N/A**
Water Injection	**Yes**	**15%**
Steam Injection	**No**	**N/A**
Selective Catalytic Reduction	**Yes**	**65%**

2.1.2.1. Good Combustion Practices

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from combustion turbines; therefore, it has been determined that this method of NO_X control is feasible for the units at Cunningham. However, these practices are currently in use at Cunningham, as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices has been included in this report.

2.1.2.2. Improved Dry Low NO_X Hardware

The dry low NO_X (DLN) control, also seeks to reduce the combustion temperature and residence time of fuel in the combustor (thereby decreasing NO_X formation) by increasing the air-to-fuel ratio in the combustion

[4] Ibid.

chamber. There are several levels of improvements that can be made to the combustion chamber, which achieve this NO_X control at varying levels.

DLN combustors are currently installed on the combustion turbines operating at this facility. While emissions may fluctuate, on average, the turbines installed at this facility are capable of achieving a NO_X stack concentration of 15 ppm and 25 ppm during normal and power augmented operation, respectively. According to Seimens, there are no improved low NO_X burners commercially available for these units.

2.1.2.3. Water/Steam Injection

Water or steam injection is a technology that has been demonstrated to effectively suppress NO_X emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.

Xcel engineers stated that Steam injection may not be implemented on the combustion turbines at Cunningham.

The pilot nozzle is the main contributor to thermal NO_x formation and water injection is capable of reducing NO_x emissions with a minimum control efficiency of 15%.[5]

2.1.2.4. Selective Catalytic Reduction Systems

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust downstream of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[6] The chemical reactions for this process are shown in the equations below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O \quad \text{(Equation 1)}$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O \quad \text{(Equation 2)}$$

An SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and an electronic control system. The electronic controls regulate the quantity of reagent injected as a function of turbine load, speed, and temperature, so NO_X emissions reductions can be achieved. The lifespan of the catalyst is primarily determined by poisoning of active sites by flue gas constituent, thermal sintering, or compacting, of active sited due to high temperatures in the reactor, fouling caused by ammonia-sulfur salts and particulate matter in the gas, and erosion due to high gas velocities.[7]

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as ammonia slip. Unreacted ammonia in the exhaust can form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.[8]

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[5] Ibid.
[6] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
[7] Ibid.
[8] Ibid.

In order for the SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 and 850 °F), dependent on the material of the catalyst. Exhaust gas temperatures greater than the upper limit will cause the NO_X and ammonia to pass through the catalyst unreacted.[9] The exhaust temperature of the turbines assessed here is approximately 580 °F.

SCR units can achieve a minimum NOx reduction of 65%.[10] However, if the upstream NO_X concentration is already low, as is the case with these units, it is difficult to achieve these control efficiencies.

There may also be site-specific space limitations that prevent the installation of the necessary equipment for this control method (i.e., SCR module and reagent storage systems).

Moreover, installation of SCR on simple cycle peaking turbines is much more difficult than installation on combined cycle turbines operating as base load units for several reasons, as follows:

- There are significant technical and financial challenges associated with the elevated exhaust temperature from simple cycle operation;
- Combined-cycle facilities have heat recovery steam generator (HRSG) ductwork that can better accommodate catalyst installation; and
- Combined-cycle cogeneration units typically operate in a continuous mode compared to peaking units which do not operate continuously and ramp up and down quickly from standing start to full load operation.

Assuming that the space and temperature limitations can be overcome, SCR is considered a technically feasible control option for this process.

2.1.3. Potential SO_2 Controls for a Combustion Turbine

2.1.3.1. Good Combustion Practices and Fuel Selection

As stated in the background information for emissions from combustion turbines, SO_2 emissions from these units are based on the sulfur content of the fuel gas. The current permitted SO_2 PTE for the turbines is based on a fuel sulfur content of 5.25 gr/100 scf. These emissions were originally permitted under PSD Permit No. 0622-M2 issued on 2/10/1997. At the time, this was consistent with Xcel's definition of "sweet gas" and the representative sulfur content was considered appropriately conservative. However, the actual sulfur content at the facility is typically 0.3 gr/100 scf and does not ever exceed 1.25 gr/100 scf. According to 2016 emission inventory data, which is based off continuous emission monitoring system (CEMS) data, actual SO_2 emissions for these units are less than 1 lb/hr on average. No additional sulfur reduction controls are reasonable or necessary.

2.2. INDUSTRIAL BOILERS

2.2.1. Industrial Boilers Background

As with natural gas turbines, of the three NO_X formation mechanisms, both fuel and prompt NO_X are negligible for natural gas industrial boilers. Thermal NO_X results from the oxidation of atmospheric nitrogen in the high-temperature, post-flame region of a combustion system. The major factors that influence thermal NO_X formation

[9] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines".

[10] Ibid.

are temperature, concentrations of oxygen and nitrogen, and residence time. If the temperature or the concentration of oxygen or nitrogen can be reduced quickly after combustion, thermal NO_X formation can be suppressed or quenched.

The formation of thermal, prompt, and fuel NO_X in combustion systems is controlled by modifying the combustion gas temperature, residence time, and turbulence. Of primary importance are the localized conditions-within and immediately following the flame zone where most combustion reactions occur. In utility boilers, temperature, residence time, and turbulence are determined by factors associated with boiler and burner design, fuel characteristics, and boiler operating conditions.

2.2.2. Potential NO_X Controls for Industrial Boilers

The retrofit control equipment identified for industrial boilers during a comprehensive review of the RBLC are reported in Table 3. A detailed discussion including a description, the technical feasibility, and the estimated performance of each control, is provided below.

Table 3. Potential Control Equipment for Industrial Boilers

Control Equipment	Technically Feasible	NO_X Control Efficiency
Good Combustion Practices	**Base Case**	**N/A**
Combustion Control Techniques	**Base Case for Unit 2, No for Unit 1**	**N/A**
Flue Gas Recirculation	**No**	**N/A**
Selective Catalytic Reduction	**Yes**	**80%**

2.2.2.1. Good Combustion Practices

NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_X emissions from boilers; therefore, it has been determined that this method of NO_X control is feasible for the units at Cunningham. However, these practices are currently in use at Cunningham, as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices has been included in this report.

2.2.2.2. Combustion Control Techniques

Similar to low NO_X burners for turbines, these controls reduce NO_X by sectioning the combustion process into stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_X formation. Minimum NO_X emission reductions of 40% have been observed with low NO_X burners [11].

Xcel has implemented an overfire air control on Unit 2 at this facility, which involves modifying the fourth level of combustion burners in the boiler. Unit 1 at the facility only has three levels of combustion burners and cannot be modified to include the overfire air technique used on Unit 2. Moreover, there are no commercially available controls that may be installed on these units at this time.

Based on this information, Xcel cannot implement any additional low NO_X burners or staging modifications at this time and no options are evaluated in this report.

2.2.2.3. Flue Gas Recirculation

In a Flue Gas Recirculation (FGR) system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed into the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NO_X emissions by two mechanisms. Primarily, the recirculated gas acts as a diluent to reduce combustion temperatures, thus suppressing the thermal NO_X formation mechanism. To a lesser extent, FGR also reduces NO_X formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is a key operating parameter influencing NO_X emission reduction potential for these systems.

FGR on these boilers would require ductwork and structural steel additions to bring exhaust gas from the stack back into the furnace windboxes. This would necessitate a re-design of the windboxes so that they could properly receive the new source and damper changes to properly mix the flow and maintain the proper air/fuel ratio. This option would also require an additional fan in the new duct work to match the pressure of the existing FD fan. Additionally, the air portion of the burner nozzles in the boilers would also need to be enlarged. The entire system would require extensive controls changes to balance air and fuel. While the cost of the FGR would likely not justify this modification, since the technique would provide a limited reduction in NO_X, the modifications needed to implement FGR are prohibitive. Moreover, Xcel has determined that the structural changes required to implement this control cannot be incorporated in due to space limitations at the facility.

This option is not considered technically feasible and is therefore not evaluated further in this report.

2.2.2.4. Selective Catalytic Reduction

The selective catalytic reduction (SCR) system for industrial boilers involves injecting ammonia (NH_3) into the flue gas in the presence of a catalyst to reduce NOx emissions. No data were available on SCR performance on

[11] U.S. EPA, AP-42, Section 1.4, "Natural Gas Combustion"

natural gas-fired boilers at the time of this publication. However, the Alternative Control Techniques (ACT)[12] document for utility boilers estimates a minimum NO_X reduction efficiency of 80%.[13]

This control is considered technically feasible and is assessed further in this report.

[12] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

[13] U.S. EPA, AP-42, Section 1.4, "Natural Gas Combustion"

Xcel has evaluated the costs of implementing the technologically feasible control technologies as thoroughly as possible in the time provided to complete this assessment. These cost estimates are calculated according to the methods and recommendations in the EPA Air Pollution Control Cost Manual or are estimated based on cost estimated provided by equipment vendors.[14] The cost effectiveness discussion and summary tables for the turbines are provided in Table 4.

3.1. TURBINE CONTROLS

Table 4. Cost Analysis Summary of Technically Feasible Controls for Combustion Turbines

Control Equipment	Unit No.	Cost Effectiveness	Cost Factors
Water Injection	3	$81,395 per ton	Equipment costs, Annual operating costs.
	4	$41,515 per ton	
Selective Catalytic Reduction	3	$97,583 per ton	Equipment costs, Annual operating costs.
	4	$49,771 per ton	

3.1.1. Water Injection

Xcel received a cost estimate to implement water injection control on the combustion turbine at the Cunningham Station. This cost estimate is reported to be $2.24 million per unit for equipment, plus an additional $340,000 associated with annual operating cost. The control efficiency for water injection is estimated to be 15% resulting in an emission rate reduction of 6.48 tpy and 12.71 tpy for Units 3 and 4, respectively. This results in an estimated cost effectiveness of $81,395and $41,515 per ton of reduced emissions for Units 3 and 4, respectively.

3.1.2. Selective Catalytic Reduction

Xcel obtained total cost estimates for a turbine SCR from CECO-Peerless. The estimate incorporates direct capital cost for equipment and vendor labor, indirect costs associated with Xcel's internal labor, and overhead and contingency costs for the project. According to this estimate, the SCR would cost $30.2 million per unit with $207,794 per year in operating costs. According to the manufacturer guaranteed control performance, the unit will reduce NO_X emissions with an 65% efficiency resulting in an emission rate reduction of 28.08 tpy and 55.06 tpy for Units 3 and 4, respectively. This results in an estimated cost effectiveness of $97,583 and $49,771 per ton of reduced emissions for Units 3 and 4, respectively.

[14] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

3.2. INDUSTRIAL BOILER CONTROLS

Table 5. Cost Analysis Summary of Technically Feasible Controls for Industrial Boilers

Control Equipment	Unit No.	Cost Effectiveness	Cost Factors
Selective Catalytic Reduction	1	$9,451 per ton	Equipment costs, Annual operating costs
	2	$5,229 per ton	

3.2.1. Selective Catalytic Reduction

To estimate the cost of a SCR unit for the boilers operating at the Cunningham Station, Xcel utilized the EPA Cost Control Manual spreadsheet. According to the cost estimation spreadsheet, the cost for Unit 1 would be $11.1 million with $145,035 annual direct costs, and $830,337 in annual indirect costs. The lifetime of the control is estimated to be 20 years and the emissions reduction from this control is estimated to be 114.00 tpy based on an assumed 80% control efficiency and uncontrolled annual emissions of 142.5 tpy (2016 emission inventory data). This results in a cost of $9,451/ton NO_X removal.

Unit 2 would cost $21.98 million with $620,558 in annual direct costs, and $1.84 million in annual indirect costs. The lifetime of the control is estimated to be 20 years and the emissions reduction from this control is estimated to be 471.12 tpy based on an assumed 80% control efficiency and uncontrolled annual emissions of 588.90 tpy (2016 emission inventory data). This results in a cost of $5,229/ton NO_X removal.

The second factor in this analysis is the time necessary for compliance. Consideration of this factor involves estimating the time required for a source to implement a potential control measure. This information is provided here in order to advise the NMED of Xcel's projection of a reasonable compliance timeline based on the equipment and site-specific considerations that could affect the time necessary to comply.

4.1. TURBINE CONTROLS

4.1.1. Water Injection

Xcel estimates that approximately 18 months will be needed to order, deliver, and install this equipment at the Cunningham Station.

4.1.2. Selective Catalytic Reduction

Xcel estimates that approximately 30 months will be needed to budget, design, procure, and construct this equipment.

4.2. INDUSTRIAL BOILER CONTROLS

4.2.1. Selective Catalytic Reduction

Xcel estimates that approximately 30 months will be needed to budget, design, procure, and construct this equipment.

5.1. TURBINE CONTROLS

5.1.1. Water Injection

Water injection is usually accompanied by an efficiency penalty (typically 2% to 3%), but an increase in power output (typically 5% to 6%).[15] The increased power output results from the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are significantly increased by water injection, with the level of CO and VOC increases dependent on the amount of water injection.[16] This increase in emissions could potentially warrant the installation of an oxidation catalyst, levying significant additional costs on Xcel to implement this control.

Additionally, depending on the model and capacity of a turbine, approximately 31 to 70 gpm may be needed to properly implement this control.[17] For a continuously operating turbine, this would represent a total water usage of 16.3 to 36.8 million gallons per year, per unit, without taking into consideration leaks and evaporative losses that would occur during transport. The implementation of this control across the Permian Basin may pose a significant burden on this semi-arid region's watershed, in which water availability is relatively sparse.

5.1.2. Selective Catalytic Reduction

The implementation of SCR on the turbines at the Cunningham Station would result in several energy and non-air environmental impacts. The primary impact of this control would be a significant increase in energy consumption, which would be necessary to power the units. Xcel does not anticipate any issues with meeting this increased energy burden.

In addition to the increased energy burden, there are several non-air environmental impacts associated with the handling and storage of the reagent used in the SCR system, typically ammonia or urea. Ammonia is a Toxic Air Pollutant (TAP) regulated under 20.2.72.502 NMAC with an occupational exposure limit (OEL) of 18 mg/m^3. In both soil and water, urea is hydrolyzed quickly to ammonia and carbon dioxide by urease, an extracellular enzyme that originates from microorganisms and plant roots.[18] Short-term inhalation exposure to high levels of ammonia in humans can cause irritation and serious burns in the mouth, lungs, and eyes. Chronic exposure to airborne ammonia can increase the risk of respiratory irritation, cough, wheezing, tightness in the chest, and impaired lung function in humans. Animal studies also suggest that exposure to high levels of ammonia in air may adversely affect other organs, such as the liver, kidney, and spleen.[19] Unavoidable releases of ammonia could have significant and irreversible impacts on the living and physical environment affected. Storage and handling of urea or ammonia onsite would result in an increased risk to the health and safety of facility operators.

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[15] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines".

[16] Ibid.

[17] GE Turbines: "Water Reduction for NO_X". https://www.ge.com/power/services/gas-turbines/upgrades/water-injection-for-nox-reduction.

[18] U.S. EPA, EPA/635/R-10/005F, "Toxilogical Report of Urea", July 2011.

[19] U.S. EPA, EPA/635/R-16/163Fc, "Toxicological Review of Ammonia Noncancer Inhalation: Executive Summary", September 2016.

5.2. INDUSTRIAL BOILER CONTROLS

5.2.1. Selective Catalytic Reduction

The implementation of SCR on the boilers at the Cunningham Station would result in several energy and non-air environmental impacts. The primary impact of this control would be a significant increase in energy consumption, which would be necessary to power the units. Xcel does not anticipate any issues with meeting this increased energy burden.

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[20] U.S. EPA, EPA/635/R-10/005F, "Toxilogical Report of Urea", July 2011.
[21] U.S. EPA, EPA/635/R-16/163Fc, "Toxicological Review of Ammonia Noncancer Inhalation: Executive Summary", September 2016.

6.1. TURBINE CONTROLS

6.1.1. Water Injection

The estimated lifetime of a water injection control system is 15 years. This estimate has been incorporated in the cost analysis section to calculate the total annualized cost of the control.

6.1.2. Selective Catalytic Reduction

The estimated lifetime of a SCR control system is 20 years. This estimate has been incorporated in the cost analysis section to calculate the total annualized cost of the control.

6.2. INDUSTRIAL BOILER CONTROLS

6.2.1. Selective Catalytic Reduction

The estimated lifetime of a SCR control system is 20 years. This estimate has been incorporated in the cost analysis section to calculate the total annualized cost of the control.

Based on a comprehensive review of the RBLC, available literature, and manufacturer's input on the available control technologies for the natural-gas fired turbines located at the Cunningham Station, Xcel has determined that it is not technically feasible or cost effective to implement any controls on equipment at this time.

Xcel Energy

Cunningham Station

Boiler	Interest Rate:	5.50%	
Unit 1	Period:	20	years

Base Emissions

NO_X lb/hr:	63.25	lb/hr	<-- From 2016 EI calculations
NO_X tpy:	142.50	tpy	<-- From 2016 EI calculations

SCR

NO_X guarantee:		80%	Control Eff.	<-- Assumed for SCR, AP-42 Section 1.4.4
NO_X lb/hr:		12.65	lb/hr	
NO_X tpy:		28.50	tpy	
Total Cap Investment	$	11,118,368		<--EPA Cost Estimate Spreadsheet
Annualized TCI:	$	930,378		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	147,054		<--EPA Cost Estimate Spreadsheet
Total Annual Costs:	$	1,077,431		
Emissions Reduction:		114.00	tpy	
Cost Effectiveness:	**$**	**9,451.15**	**$/ton**	

Xcel Energy

Cunningham Station

Boiler	Interest Rate:	5.50%	
Unit 2	Period:	20 years	

Base Emissions			
NO_X lb/hr:	146.49	lb/hr	<-- From 2016 EI calculations
NO_X tpy:	588.90	tpy	<-- From 2016 EI calculations

SCR			
NO_X guarantee:	80%	Control Eff.	<-- Assumed for SCR, AP-42 Section 1.4.4
NO_X lb/hr:	29.30	lb/hr	
NO_X tpy:	117.78	tpy	
Total Cap Investment	$ 21,981,248		<-- EPA Cost Estimate Spreadsheet
Annualized TCI:	$ 1,839,376		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 624,288		<-- EPA Cost Estimate Spreadsheet
Total Annual Costs:	$ 2,463,665		
Emissions Reduction:	471.12	tpy	
Cost Effectiveness:	**$ 5,229.38**	**$/ton**	

Xcel Energy

Cunningham Station

Turbine	Interest Rate:		5.50%	
Unit 3	SCR Period:		20	years
	Water Injection Period:		15	years
Base: Dry Low NO_X				
NO_X lb/hr:		54.10	lb/hr	<-- From 2016 Emission Inventory Report
NO_X tpy:		43.20	tpy	<-- From 2016 Emission Inventory Report

Water Injection

NO_X guarantee:		15%	Control Eff.	<-- Assumed for SCR, AP-42 Section 3.1.4.1
NO_X lb/hr:		45.99	lb/hr	
NO_X tpy:		36.72	tpy	
Total Cap Investment	$	2,240,000		<-- Vendor Estimate
Annualized TCI:	$	187,442		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	340,000		<-- Vendor Estimate
Total Annual Costs:	$	527,442		
Emissions Reduction:		6.48	tpy	
Cost Effectiveness:	**$**	**81,395.32**	**$/ton**	

[1] From Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Timeline for Compliance (Docket ID No. EPA-HQ-OAR-2015-0500) Section 3.3.1, Corrected from 1999 to 2018 dollars based on CEPCI.

SCR

NO_X guarantee:		65%	Control Eff.	<-- Assumed for SCR, AP 42 Section 3.4.1.3
NO_X lb/hr:		18.94	lb/hr	
NO_X tpy:		15.12	tpy	
Total Cap Investment	$	30,262,542		<-- From Vendor
Annualized TCI:	$	2,532,349		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	207,794		<-- from Vendor
Total Annual Costs:	$	2,740,143		
Emissions Reduction:		28.08	tpy	
Cost Effectiveness:	**$**	**97,583.46**	**$/ton**	

Xcel Energy

Cunningham Station

Turbine	Interest Rate:		5.50%	
Unit 4	SCR Period:		20	years
	Water Injection Period:		15	years
Base: Dry Low NO_X				
NO_X lb/hr:		59.48	lb/hr	<-- From 2016 Emission Inventory Report
NO_X tpy:		84.70	tpy	<-- From 2016 Emission Inventory Report
Water Injection				
NO_X guarantee:		15%	Control %	<-- Assumed for SCR, AP-42 Section 3.1.4.1
NO_X lb/hr:		50.56	lb/hr	
NO_X tpy:		72.00	tpy	
Total Cap Investment	$	2,240,000		<-- Vendor Estimate
Annualized TCI:	$	187,442		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	340,000		<-- Vendor Estimate
Total Annual Costs:	$	527,442		
Emissions Reduction:		12.71	tpy	
Cost Effectiveness:	**$**	**41,514.50**	**$/ton**	
SCR				
NO_X guarantee:		65%	Control %	<-- Assumed for SCR, AP-42 Section 3.1.4.3
NO_X lb/hr:		20.82	lb/hr	
NO_X tpy:		29.65	tpy	
Total Cap Investment	$	30,262,542		<-- From Vendor
Annualized TCI:	$	2,532,349		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	207,794		<-- from Vendor
Total Annual Costs:	$	2,740,143		
Emissions Reduction:		55.06	tpy	
Cost Effectiveness:	**$**	**49,771.02**	**$/ton**	

REGIONAL HAZE FOUR-FACTOR ANALYSIS
NMED FOLLOW-UP LETTER RESPONSE
Xcel Energy, Cunningham Station

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The NMED posed the following questions regarding the emissions control options Enterprise presented for the two (2) turbines and two (2) boilers located at the Xcel Energy Cunningham Station.

COMBUSTION TURBINES

1. *Provide the details regarding Good Combustion Practices (GCP) and the routine maintenance schedule and procedures that are currently used to mitigate NO_X emissions that are employed as the base case.*
   Response: Xcel Energy implements robust Good Combustion Practice which are detailed in a Good Combustion Practices Manual that has been developed specifically for the Cunningham Station facility. This document is provided with this submission.

2. *Can documentation be obtained from Siemens to support the claim that there are no commercially available dry low NO_X (DLN) burners that would provide lower emissions than those already installed on the combustion turbines?*
   Response: Correspondence from Dan Johnson (Siemens Energy) is attached in Appendix A confirming that DLN and ULN upgrades are not commercially available for the Siemens D5A turbines installed at the Cunningham Station.

3. *Provide documentation with details from Xcel engineers that steam injection may not be implemented on the combustion turbines*.
   Response: An email from Siemens is attached in Appendix A discussing the fact that steam injection is not available for these units. The reasons include physical limitations in the combustion chamber and cost, among others. Moreover, Siemens stated that steam injection has not been installed on these units. In addition to the technical barriers the technology has not been commercially demonstrated and is therefore not considered to be a viable control option for the Turbines at the Cunningham Station

4. *Although the analysis indicates that selective catalytic reduction (SCR) may be considered a technically feasible control option, if space and temperature limitations can be overcome, please provide additional discussion on the possible space limitations; the potential significant technical and financial challenges associated with elevated exhaust temperature from the simple cycle turbines; and the drawbacks from employing this technology on peaking units when compared to continuous operation of combined-cycle units.*
   Response: As discussed in the original submission, Xcel considered space limitations and determined that there is enough space to install the SCRs. While exhaust temperature may present some issues, if needed Xcel could install a hot side SCR, which is suggested by Siemens in the email attachment to number 3, above. Specific cost and performance factors were not considered for a hot side SCR as the EPA cost estimate manual and generic AP-42 control efficiencies were used to evaluate the cost effectiveness of these units.

INDUSTRIAL BOILERS

5. *Provide the details regarding GCP and the routine maintenance schedule and procedures that are currently used to mitigate NOX emissions and are employed as the base case.*
   Response: Per the above response, please see the Good Combustion Practices manual for Cunningham Station.

6. *Please provide additional detail on the reasons why the three levels of combustion burners on Boiler Unit 1 cannot be modified to include the overfire air technique currently employed on Unit 2.*
   Response: Unit 1 is a much smaller boiler than unit 2. Overfired air involves removing the top layer of burners and replacing them with air registers. If this modification were implemented, there would not be enough burners to operate the unit. The Unit would need to be redesigned and rebuilt to add another burner layer, with air registers installed at the top. The locations of the burners would change and would require a redesign and rebuild of the piping and ductwork for air and gas delivery. Alternatively, the boiler itself could be completely redesigned and rebuilt to accommodate the implementation of overfire air. However, as stated in the Guidelines for BART determinations Under the Regional Haze Rule, the general types of modifications that shall be considered under this analysis include the implementation of lower emitting processes or practices and add-on controls. Moreover, the guidance states that this analysis shall not be considered as a "requirement to redesign the source when considering available control alternatives."[1] Therefore, neither of these options to accommodate overfire air are a viable option.

7. *There are other NOX reduction technologies that may be applicable to the Cunningham Station's boilers. Please include a discussion on the technical feasibility on the following technologies:*
   a. *ECOTUBE;*
      Response: The ECOTUBE technology is a combination of SCR and overfire air technology. Since overfire air controls cannot be implemented on Unit 1, this would not be feasible on that unit, as well. Moreover, since overfire air is currently installed on Unit 2 and we have evaluated SCR controls for that unit, it is not clear that there would be any additional benefit from this control.

      The Eastern Research Group prepared a report for the Clean Air Strategic Alliance on Control technologies for the Electricity Framework.[2] (). The report noted that this technology had not been commercially demonstrated on demonstrated on large boilers. The technology was therefore excluded from the analysis. The Navajo Generating Station in Tempe, AZ conducted a BART analysis for the previous Regional Haze Rule Planning period. The ECOTUBE technology was eliminated from consideration using this same reasoning. This determination was submitted to and accepted by WRAP. This technology will not be considered further by Xcel for use on the boilers operating at Cunningham Station.

   b. *LoTOx;*
      Response: LoTOx technology is a relatively recent technology that to this point has not been widely used. While the Manufacturer, Linde, LLC, states that the technology is commercially available, no technical documentation could be found to demonstrate robust commercial use of

[1] 40 CFR 51 Appendix Y Section IV.D.1.5

[2] Electricity Framework 5 Year Review – Control Technologies Review, ERG No. 3689.00.001.001, Prepared for Clean Air Strategic Alliance by Eastern Research Group (2009) http://www.assembly.ab.ca/lao/library/egovdocs/2009/ca6/casa/173276.pdf

the technology. Very limited information exists on this technology: this control technology was not found in the RBLC and no discussions on this control were included in AP-42, the EPA Cost Guidance Manual, Alternative Control Techniques Document, or any other government agency or third-party organization documents.

c. *natural gas reburn;*
Response: Natural gas reburning is a synonym for overfire air burning. This technique is currently implemented on Unit 2 and cannot be implemented on Unit 1, as discussed in the response to question 2, above.

d. *$NO_X Star^{TM}$ and $NO_X Star\ Plus^{TM}$;*
Response: In the Electricity Framework 5 Year Review[3], the NO_XStar and NO_XStar Plus technology was also reported as not being commercially demonstrated on large boilers. According to the EPA Cost Manual Section 1.2.6, the NO_X control efficiency of these units at a minimum have only been demonstrated to be 45% but the cost is high; the manual states that the cost of a NO_XStar unit is approximately $60 to $75 per kW. Unit 1 and 2 have rating of 82 MW and 234 MW, respectively, yielding approximate costs of $6.15 million and $17.55 million. While SCR units have total capital costs of $11.11 and $21.98 million, they provide a much higher NOx control efficiency of 80%. Because this technology is not widely used, has not been commercially demonstrated on large boilers, and would not be cost effective, the unit is not being considered as a viable option.

e. *regenerative SCR (RSCR);*
Response: No literature was found to be available on regenerative SCRs. It is noted that SCR catalyst elements may be regenerated, but it is not clear how this differs significantly from a standard SCR.

f. *selective non-catalytic combustion*
Response: Selective non-catalytic reduction techniques have relatively poor performance compared to SCRs; AP-42 Section 1.4.4 states a NO_X control efficiency of 24%. Additionally, the unit was not identified as a control that has been implemented in the last 10 years in the RBLC. For this reason, the control was not considered.

Although the unit is somewhat cheaper than a SCR, Xcel does not believe this would demonstrate that this technology would be more cost effective. According to the EPA Air Pollution Control Technology Fact Sheet for SNCR units the cost estimates for the units would be as follows:

Costs from the "Air Pollution Control Technology Fact Sheet" for Selective Non-Catalytic Reduction		
Capital Cost ($/MW)	$	25,000
O&M Cost ($/MW)	$	5,000
Other Annualized Costs ($/MW/yr)	$	1,000

[3] Ibid.

	Unit 1	Unit 2	Notes
Boiler Rating (MW)	82	234	
Capital Cost	$ 2,050,000	$ 5,850,000	
O&M Cost	$ 410,000	$ 1,170,000	
Lifetime Annualized Costs	$ 1,640,000	$ 4,680,000	SNCR lifetime is assumed to be 20 years
Total Cost	$ 4,100,000	$ 11,700,000	Capital, O&M, and other annualized costs
Annualized TCI	$ 343,085.25	$ 979,048.16	Amortized over 20 years w/ 5.5% interest
Baseline Emissions (tpy)	142.50	588.90	2016 emission inventory data
Control Efficiency (%)	24%	24%	AP-42 Section 1.4.4
Tons Controlled (tpy)	34.20	141.34	Control efficiency * baseline emissions
Cost Per Ton ($/ton)	$10,031.73	$6,927.10	Annualized TCI / tons controlled

Based on the above cost information, the SNCR technology is slightly less cost effective than SCR technology. Xcel does not anticipate that there are any site-specific environmental or non-air impacts from this control technology.

COST OF COMPLIANCE

1. *Please provide copies of all vendor quotes used for determining the cost of compliance and copies of electronic spreadsheets used to calculate cost effectiveness.*
   Response: A vendor quote of the water injection quote is provided in Appendix A. Additional cost associated with the installation and operation of water injection were calculated using the EPA Cost Manual. SCR equipment costs are calculated using the EPA Cost Manual spreadsheets. Other installation costs associated with this unit were estimated by Xcel. Documentation of all these costs are included in an electronic spreadsheet.

2. *Provide a vendor quote to refine the cost effectiveness estimates for installation of SCR units on the boilers.*
   Response: With the understanding that vendor quotes were not required to estimate equipment cost and in accordance with guidance from the NMED (as provided on the Regional Haze website), the EPA Cost Manual Spreadsheets were used to estimate the costs of SCR units for the boilers. The electronic spreadsheet is attached with the EPA cost spreadsheets included.

APPENDIX A: VENDOR DOCUMENTION

From: Johnson, Dan
To: Taylor, Douglas B
Subject: Siemens Mature D-Frame Units
Date: Thursday, February 06, 2020 11:17:52 AM

CAUTION EXTERNAL SENDER: Stop and consider before you click links or open attachments.
Report suspicious email using the 'Report Phishing/Spam' button in Outlook.

Doug,

Siemens Energy does not provide an ULN upgrade for mature D-Frame gas turbines. The technology is only available for F-Frame and newer gas turbines.

Kind Regards,
Dan Johnson
Siemens Energy
Power Systems Sales
469-900-7841

From: Johnson, Dan
To: Taylor, Douglas B
Subject: RE: Question about power augmentation steam injection
Date: Tuesday, January 14, 2020 2:26:53 PM

CAUTION EXTERNAL SENDER: Stop and consider before you click links or open attachments.
Report suspicious email using the 'Report Phishing/Spam' button in Outlook.

Doug,

The Cheng cycle seems to be something new to the market. A few data points from their web page:

- Not possible to get a 50-90% MW increase. Shaft limit prevents it, even on a hot day. Not certain if Xcel can utilize a rate increase without NSR?
- It's doubtful that the generator would accept that power increase, either, so – new generator required = $$$$$.
- It is doubtful that a GT will accept the "massive" amount of steam that Cheng describes without serious consideration of dynamics/flame stability. Could be more a hindrance than a benefit if just for emissions reduction.
- We do not agree with the efficiency increase promised without a HRSG driven steam turbine.
- Can't tell how much make-up water will be consumed to make the massive amounts of steam. It could be quite a bit which would get expensive.
- Even if the Cheng cycle could be economically implemented on a GT, the Isophase bus duct, GSUT or T&D in the yard would likely be the next bottleneck.

Before doing any thermodynamics, the feasibility is low. The concept is interesting, but sketchy at the same time and the website is scant on details.

Success seems more likely if used on a new unit installation so that all BOP could be sized correctly.

Siemens has not installed steam injected on D5A DLN units.

In order for to do steam injection a HRSG is necessary and site engineering and construction would be expensive. In Siemens opinion, Cunningham should look at a hot SCR.

Dan

From: Taylor, Douglas B <douglas.b.taylor@xcelenergy.com>
Sent: Monday, January 13, 2020 11:20 AM
To: Johnson, Dan (GP SPG RNA PSS MW) <danny.johnson@siemens.com>
Subject: Question about power augmentation steam injection

Dan,
Were the original Westinghouse 501 D5A units we have at Cunningham set up to do steam injection as an option? I know we did wet compression on these units, but NMED is asking questions about options to improve NOx control. I already told them that Siemens doesn't offer DLN for these units.

I saw an after market offering from Cheng Power Systems call the Cheng Cycle, which uses a small single pressure HRSG to generate steam for this, and they say they have retro-fitted a D5A with this. I'm very leery of even talking to them about this. I was thinking the F machines had a steam injection port but I thought the D5A did not. Please advise.
Thanks,
Doug

Douglas B. Taylor
Xcel Energy | Responsible By Nature
Project Manager E&C
790 South Buchanan St. 5th Floor Amarillo, Texas 79101
P: 806-378-2118 **C:** 806-676-5509 **F:** 806-378-2152
E: douglas.b.taylor@xcelenergy.com

Letter Containing Confidential Vendor Information Omitted

Xcel Energy's Cunningham Station was identified as a facility that may potentially have an impact on visibility at the Carlsbad Caverns National Park. The NMED used a Q/d analysis of all the major sources in New Mexico to make this determination, where "Q" is the facilities emission rate of NO_X and SO_2 and "d" is the distance of the facility to a national park. There are several disadvantages to evaluating facility impact in this manner. The methodology does not take into consideration the plethora of minor sources with a much closer proximity to the Class I area. Additionally, the driving factor of a facility's relative impact on a Class I area is the prevailing meteorological conditions in the region.

The Cunningham Station is located 69.3 miles away from the Carlsbad Caverns Class I area at a wind vector of 58 degrees (northeast). The wind roses reported in Figures 1 and 2 below show that the prevailing wind direction in Carlsbad are bi modal blowing mostly from the SE and NW and the wind in Hobbs, NM blow mostly from the south. The wind climatology of these locations does not favor pollutant transport from the Cunningham Station to the Carlsbad Cavern Class I area.

It is understood, however that pollutants are not transport in a straight line and that, over an extended period of time, while unlikely, it is plausible that pollutants emitted by the Cunningham Station could be transported to the Carlsbad Caverns. To evaluate this transport, HYSPLIT modeling has been employed. The results of this modeling are discussed in this Appendix.

Figure 1. 2015 Wind Rose of Wind Speed vs. Wind Direction in Carlsbad, NM.

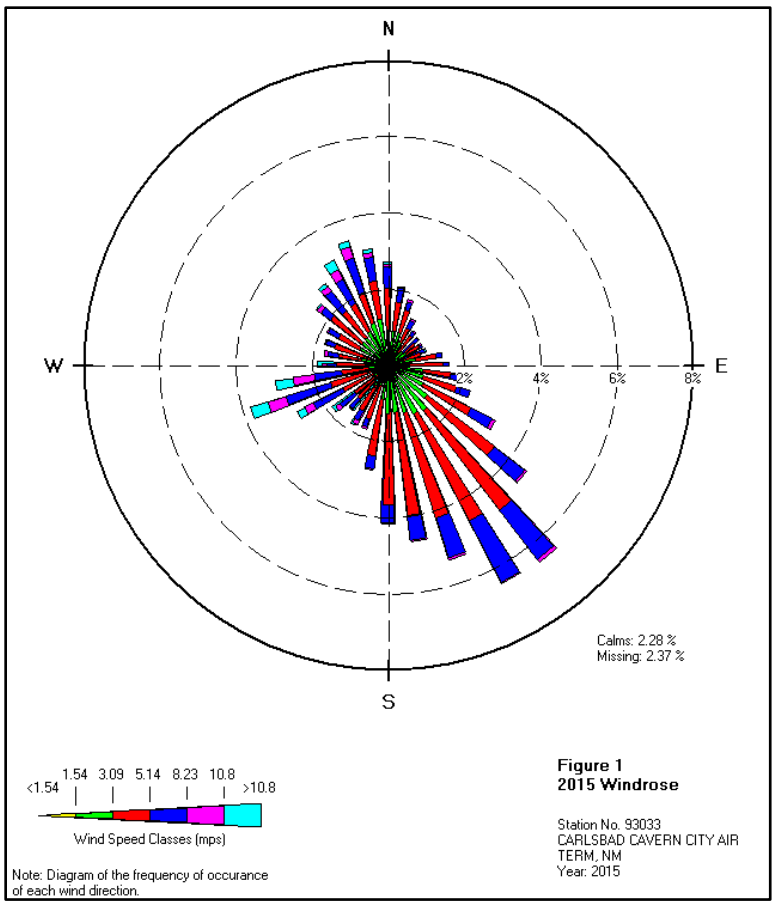
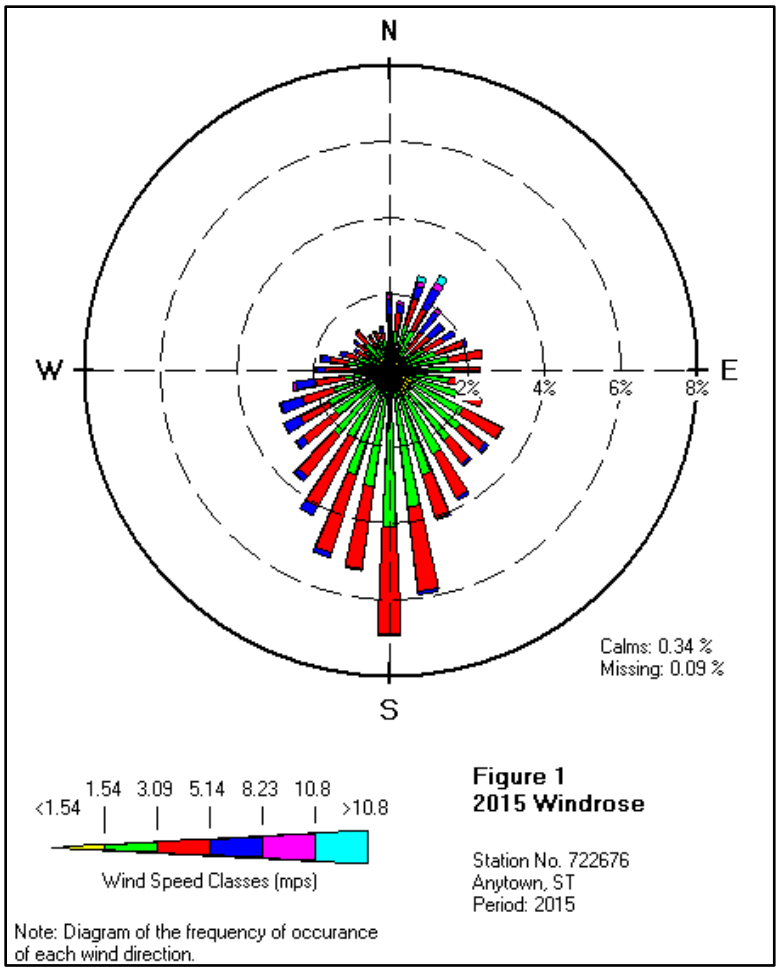


Figure 2. 2015 Wind Rose of Wind Speed vs. Wind Direction in Hobbs, NM.



HYSPLIT MODEL – OVERVIEW

HYSPLIT is a hybrid model using both the Lagrangian approach, which uses a moving frame of reference for the advection and diffusion calculations as the trajectories or air parcels move from their initial location, and the Eulerian methodology, which uses a fixed three-dimensional grid as a frame of reference to compute pollutant air concentrations. The dispersion of a hypothetical pollutant is calculated by assuming either puff or particle dispersion. The back-trajectory analysis utilized applies a particle model, where a fixed number of particles are advected about the model domain by the mean wind field and spread by a turbulent component. The model's default configuration assumes a 3-dimensional particle distribution (horizontal and vertical).

HYSPLIT MODEL - PROCEDURE

There are two HYSPLIT modeling techniques available: dispersion Modeling, which models the concentration of dispersed pollutants in a plume, or trajectory modeling which calculates the mean transport of pollution along a finite path. Using the trajectory modeling tool, back-trajectories were calculated every hour starting January 1, 2014, and ending December 31, 2018. The location modeled was the site of the Carlsbad Caverns IMPROVE monitor (32.1783°N, 104.4406°W).

There are several options available for meteorological datasets. In order resolve topographic features and mesoscale meteorological phenomena, the 12 km NAMM meteorological dataset was used.

The following protocol was implemented:

- A five-year look-back period (2014 through 2018) was modeled;
- The model was run for each hour of each day (i.e., 24 runs per day);
- A 48 hour back-trajectory was calculated for each of the 24 runs to capture the transport of pollutants from all nearby sources to the Carlsbad Caverns National Park. The model calculated the back-trajectories in 1-hour time steps; and
- The sigma height option was used, with an initial target height of 0.5 sigma which represents half the height of the boundary layer. This height is considered to be representative of the mean ground level ambient air, since the boundary layer is well-mixed/homogenous.

Based on the availability of meteorological data, the HYSPLIT model was able to calculate back-trajectories for 43,753 hours out of 43,824 hours (99.84%). The back-trajectories were then synthesized in a single plot that displays the frequency that trajectories pass through a grid cell. A 0.1° (approximately 10 km) grid cell network was generated using the "trajfreq" executable file that NOAA has included with their suite of HYSPLIT software. For each grid cell (i,j) in the modeling domain, the frequency (F) is calculated using the following equation:

$$F_{i,j} = 100 \Sigma T_{i,j} / N \qquad \text{(equation 1)}$$

Where T is the number of trajectories that intersect a grid cell (i,j) and N is the total number of trajectories analyzed (47,353).

To generate a figure from this data, the "concplot" executable was used, which allows the user to select the contour levels, colors, map projection and output format. Figures 3 shows the frequency plot for the Carlsbad Caverns Class I area.

Figure 3. A HYSPLIT back trajectory frequency plot for 2014 to 2018 for the Carlsbad Caverns National Park.

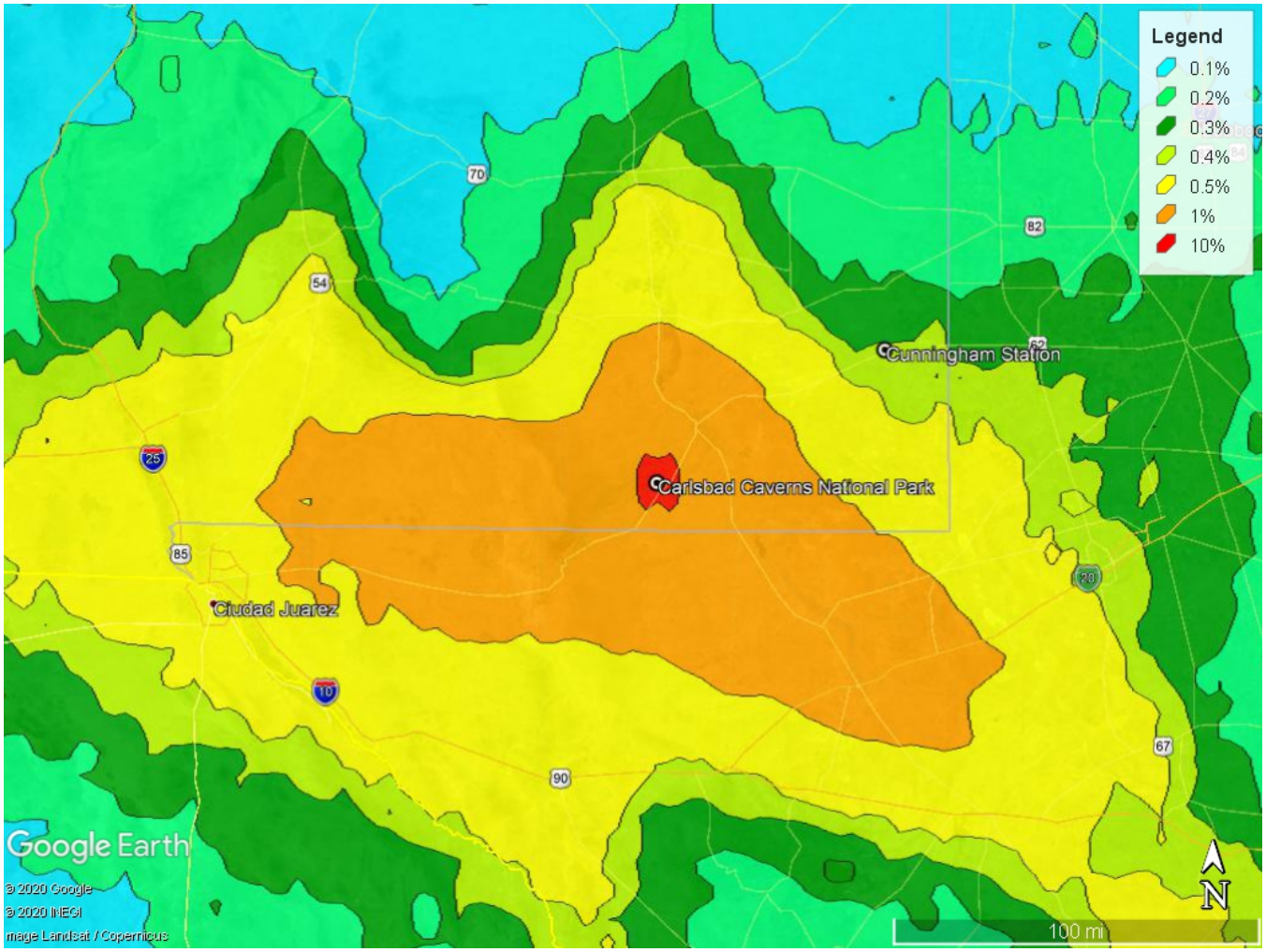


Figure 3 shows that ambient air at Cunningham Station only passes through the grid cell where the Carlsbad Caverns IMPROVE monitor is located with a frequency of approximately 0.4% or 175 hours out of the 43,753 hours that were modeled. While the costs effectiveness of controls alone would preclude the Cunningham Station from implementing any control technologies, this modeling demonstrates that such modifcations would not have an impact on visibility at the Carlsbad Caverns.

APPENDIX C: GOOD COMBUSTION PRACTICES MANUAL

GCP Manual Omitted for Brevity

Xcel Energy
Cunningham Station

Boiler	Interest Rate:	5.50%	
Unit 1	Period:	20	years

Base Emissions

NO_X lb/hr:	63.25	lb/hr	<-- From 2016 EI calculations
NO_X tpy:	142.50	tpy	<-- From 2016 EI calculations

SCR

NO_X guarantee:	80%	Control Eff.	<-- Assumed for SCR, AP-42 Section 1.4.4
NO_X lb/hr:	12.65	lb/hr	
NO_X tpy:	28.50	tpy	
Total Cap Investment	$ 11,118,368		<--EPA Cost Estimate Spreadsheet
Annualized TCI:	$ 930,378		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 147,054		<--EPA Cost Estimate Spreadsheet
Total Annual Costs:	$ 1,077,431		
Emissions Reduction:	114.00	tpy	
Cost Effectiveness:	**$ 9,451.15**	**$/ton**	

2016 Emission Inventory Data

Fuel Heating Value	1051.9	Btu/scf
Fuel Usage	1843	MMscf/yr
Heat Input	221.31	MMBtu/hr
Hours of Operation	4506	hrs/yr
NOx EF	0.29	lb/MMBtu
NOx Emissions	63.25	lb/hr
NOx Emissions	142.50	tpy

Facility Annual Emissions - Subject Item Submittal Review
Thursday, September 12, 2019

Agency ID: 604
Facility Name: Xcel Energy - Cunningham Station Power Plant
Organization Name: Southwestern Public Service Co dba Xcel Energy
Submittal Status: 2016 Submittal (Certified, Awaiting NMED Approval)

Subject Item ID: EQPT-8
Designation: 001
Description: Tangentially Fired Boiler
Type: Boiler
SCC: External Combustion Boilers, Electric Generation, Natural Gas, Boilers > 100 Million Btu/hr except Tangential
GHG Reporting: Reports GHG to EPA

Supplemental Parameters

	Amount	Unit of Measure
Fuel Type:	Natural Gas	
Input Materials Processed:	Natural Gas (INPUT)	
Materials Consumed:	1843.0	MM SCF
Fuel Heating Value:	1051.9	BTU/SCF
Percent Sulfur of Fuel:	0.0	percent
Percent Ash of Fuel:	0.0	percent
Percent Carbon Content:	73.0	percent

Operating Detail

	Value
Operating Time in Hours per Day:	24
Operating Time in Days per Week:	7
Operating Time in Weeks per Year:	52
Operating Time in Hours per Year:	4506
Percent of Operation During Winter:	2
Percent of Operation During Spring:	32
Percent of Operation During Summer:	19
Percent of Operation During Fall:	47

Actual Pollutants

Pollutant	Amount	Unit of Measure	Calculation Method
Carbon Monoxide:	7.8	tons/y	Actual stack test
Formaldehyde:	0.07	tons/y	EPA emission factors (e.g., AP-42)
Nitrogen Dioxide:	142.5	tons/y	Continuous Emission Monitoring (CEMS)
Particulate Matter (10 microns or less):	7.0	tons/y	EPA emission factors (e.g., AP-42)
Particulate Matter (2.5 microns or less):	7.0	tons/y	EPA emission factors (e.g., AP-42)
Particulate Matter (total suspended):	7.0	tons/y	EPA emission factors (e.g., AP-42)
Sulfur Dioxide:	0.6	tons/y	Continuous Emission Monitoring (CEMS)
Volatile Organic Compounds (VOC):	1.3	tons/y	EPA emission factors (e.g., AP-42)

Subject Item Comments

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	82	MW
What is the higher heating value (HHV) of the fuel?	1,052	Btu/scf
What is the estimated actual annual MWhs output?	342,456	MWhs
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 3815 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	187.75	days
Number of days the boiler operates (t_{plant})	187.75	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.29	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.087	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	25	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	700	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	15.84	ft^3/min-MMBtu/hour

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	603.1	2018 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0361	$/kWh			* $0.0361/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	-	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	-	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1025	Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	221	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	718,320	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		342,456	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.03		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.477	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4176	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	44.93	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	93.81	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.88		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	3506.5	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	5.0	/hour	
Residence Time	1/V_{space}	0.1995	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.15		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.1792	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	699.53	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	4	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	65	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	4	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	2.0	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	296	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	17	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	60	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,800	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0745

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	465.07	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$11,118,368	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$145,035 in 2018 dollars
Indirect Annual Costs (IDAC) =	$830,337 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$975,372 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$55,592 in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$9,841 in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$70,116 in 2018 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$9,485 in 2018 dollars
Direct Annual Cost =		$145,035 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,019 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$828,318 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$830,337 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$975,372 per year in 2018 dollars
NOx Removed =	94 tons/year
Cost Effectiveness =	$10,397 per ton of NOx removed in 2018 dollars

Xcel Energy
Cunningham Station

Boiler	Interest Rate:	5.50%	
Unit 2	Period:	20 years	

Base Emissions			
NO_X lb/hr:	146.49	lb/hr	<-- From 2016 EI calculations
NO_X tpy:	588.90	tpy	<-- From 2016 EI calculations

SCR			
NO_X guarantee:	80%	Control Eff.	<-- Assumed for SCR, AP-42 Section 1.4.4
NO_X lb/hr:	29.30	lb/hr	
NO_X tpy:	117.78	tpy	
Total Cap Investment	$ 21,981,248		<-- EPA Cost Estimate Spreadsheet
Annualized TCI:	$ 1,839,376		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 624,288		<-- EPA Cost Estimate Spreadsheet
Total Annual Costs:	$ 2,463,665		
Emissions Reduction:	471.12	tpy	
Cost Effectiveness:	**$ 5,229.38**	**$/ton**	

2016 Emission Inventory Data

Capacity	234	MW
Fuel Heating Value	1051.9	Btu/scf
Fuel Usage	7722	MMscf/yr
Heat Input	927.26	MMBtu/hr
Hours of Operation	8040	hrs/yr
NOx EF	0.16	lb/MMBtu
NOx Emissions	146.49	lb/hr
NOx Emissions	588.90	tpy

Facility Annual Emissions - Subject Item Submittal Review
Thursday, September 12, 2019

Agency ID: 604
Facility Name: Xcel Energy - Cunningham Station Power Plant
Organization Name: Southwestern Public Service Co dba Xcel Energy
Submittal Status: 2016 Submittal (Certified, Awaiting NMED Approval)

Subject Item ID: EQPT-9
Designation: 002
Description: Tangentially Fired Boiler
Type: Boiler
SCC: External Combustion Boilers, Electric Generation, Natural Gas, Boilers > 100 Million Btu/hr except Tangential
GHG Reporting: Reports GHG to EPA

Supplemental Parameters

	Amount	Unit of Measure
Fuel Type:	Natural Gas	
Input Materials Processed:	Natural Gas (INPUT)	
Materials Consumed:	7722.0	MM SCF
Fuel Heating Value:	1051.9	BTU/gal
Percent Sulfur of Fuel:	0.0	percent
Percent Ash of Fuel:	0.0	percent
Percent Carbon Content:	73.0	percent

Operating Detail

	Value
Operating Time in Hours per Day:	24
Operating Time in Days per Week:	7
Operating Time in Weeks per Year:	52
Operating Time in Hours per Year:	8040
Percent of Operation During Winter:	22
Percent of Operation During Spring:	27
Percent of Operation During Summer:	25
Percent of Operation During Fall:	26

Actual Pollutants

Pollutant	Amount	Unit of Measure	Calculation Method
Carbon Monoxide:	65.0	tons/y	Actual stack test
Formaldehyde:	0.29	tons/y	EPA emission factors (e.g., AP-42)
Nitrogen Dioxide:	588.9	tons/y	Continuous Emission Monitoring (CEMS)
Particulate Matter (10 microns or less):	29.34	tons/y	EPA emission factors (e.g., AP-42)
Particulate Matter (2.5 microns or less):	29.34	tons/y	EPA emission factors (e.g., AP-42)
Particulate Matter (total suspended):	29.34	tons/y	EPA emission factors (e.g., AP-42)
Sulfur Dioxide:	2.4	tons/y	Continuous Emission Monitoring (CEMS)
Volatile Organic Compounds (VOC):	5.4	tons/y	EPA emission factors (e.g., AP-42)

Subject Item Comments

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	234	MW
What is the higher heating value (HHV) of the fuel?	1,052	Btu/scf
What is the estimated actual annual MWhs output?	1,881,360	MWhs
Enter the net plant heat input rate (NPHR)	9.5	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 3815 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	335	days
Number of days the boiler operates (t_{plant})	335	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.16	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.03	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	628	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	15.8	ft^3/min-MMBtu/hour

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	603.1	2018 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0361	$/kWh			* $0.0361/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	-	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	-	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	927	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	2,049,840	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		1,881,360	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	0.95		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.918	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8040	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	117.19	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	471.12	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	13,780	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	3.69	/hour	
Residence Time	1/V_{space}	0.27	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.15		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,733.67	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	14	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	88	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	17	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	4.1	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	388	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	46	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	157	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	21	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	7,100	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	1281.81	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$21,981,248	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$620,558 in 2018 dollars
Indirect Annual Costs (IDAC) =	$1,843,561 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$2,464,119 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$109,906 in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$49,423 in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$372,039 in 2018 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$89,190 in 2018 dollars
Direct Annual Cost =		$620,558 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,731 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,839,830 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,843,561 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,464,119 per year in 2018 dollars
NOx Removed =	471 tons/year
Cost Effectiveness =	$5,230 per ton of NOx removed in 2018 dollars

Xcel Energy
Cunningham Station

Turbine	Interest Rate:	5.50%		
Unit 3	SCR Period:	20	years	
	Water Injection Period:	15	years	

Base: Dry Low NO_x

NO_x ppm:	25	ppm	<-- With Power Augmentation (Permitted)
NO_x lb/hr:	54.10	lb/hr	<-- From 2016 Emission Inventory Report
NO_x tpy:	43.20	tpy	<-- From 2016 Emission Inventory Report

Water Injection

NO_x guarantee:	12%	Control Eff.	<-- Vendor Information (Decrease by 3 ppm)
NO_x lb/hr:	47.61	lb/hr	
NO_x tpy:	38.02	tpy	
Total Equipment Cost[2]	$ 2,030,510		<-- Vendor Quote with 10% Contingency
Indirect and Direct Installation Costs[3]	$ 290,363		<--EPA Cost Manual Section 4.2
Allowance Funds During Construction[4]	$ 464,175		<--EPA Cost Manual Section 4.2
Project Contingency[4]	$ 586,005		<--EPA Cost Manual Section 4.2
Total Cap Investment	$ 3,371,053		<-- Equipment, Installation, Allowance, and Contingency
Annualized TCI	$ 282,087		<-- Based on interest rate, year and TCI
Annual O&M Costs[5]	$ 57,764		<-- Electricity, Water, and Maintenance
Total Annual Costs:	$ 339,851		
Emissions Reduction:	5.18	tpy	
Cost Effectiveness:	**$ 65,557.67**	**$/ton**	

1 From Assessment of Non-EGU NO_x Emission Controls, Cost of Controls, and Timeline for Compliance (Docket ID No. EPA-HQ-OAR-2015-0500) Section 3.3.1, Corrected from 1999 to 2018 dollars based on CEPCI.

2 Total Capital Cost from Seimens April 2008 quotation. The cost includes instrumentation, sales tax and freight and is corrected from 2008 dollars to 2018 dollar using CEPCI ratios. 2018 CEPCI = 603.1, 2008 CEPCI = 575.4.

3 Estimates based on engineering knowledge and evaluation of costs for other equipment as specified in OAQPS Manual.

4 OAQPS Section 4.2 Chapter 2, Table 2.5

5 OAQPS Default, Section 4.2, Chapter 2, pages 2.45 and 2.46. Calculated based on water and energy usage from vendor.

SCR

NO_x guarantee:	65%	Control Eff.	<-- Assumed for SCR, AP 42 Section 3.4.1.3
NO_x lb/hr:	18.94	lb/hr	
NO_x tpy:	15.12	tpy	
Equipment Costs:	$ 15,373,721		<-- EPA Cost Tool
Installation Engineering & Labor:	$ 12,544,890		<-- Xcel Estimates
Total Cap Investment	$ 30,262,542		<-- Equipment, Installation Engineering and Labor
Annualized TCI:	$ 2,532,349		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 108,231		<-- EPA Cost Tool
Total Annual Costs:	$ 2,640,580		
Emissions Reduction:	28.08	tpy	
Cost Effectiveness:	**$ 94,037.76**	**$/ton**	

2016 Emission Inventory Data

Fuel Heating Value	1051.9	Btu/scf
Fuel Usage	1523	MMscf/yr
Heat Input	182.9	MMBtu/hr
Hours of Operation	1597	hrs/yr
Days of Opeartion	66.5	days/yr
NOx EF	0.30	lb/MMBtu
NOx Emissions	54.10	lb/hr
NOx Emissions	43.20	tpy

Facility Annual Emissions - Subject Item Submittal Review
Thursday, September 12, 2019

Agency ID: 604
Facility Name: Xcel Energy - Cunningham Station Power Plant
Organization Name: Southwestern Public Service Co dba Xcel Energy
Submittal Status: 2016 Submittal (Certified, Awaiting NMED Approval)

Subject Item ID: EQPT-3
Designation: 003
Description: Simple Cycle Gas Turbine
Type: Turbine
SCC: Internal Combustion Engines, Electric Generation, Natural Gas, Turbine
GHG Reporting: Reports GHG to EPA

Supplemental Parameters

	Amount	Unit of Measure
Fuel Type:	Natural Gas	
Input Materials Processed:	Natural Gas (INPUT)	
Materials Consumed:	1523.0	MM SCF
Fuel Heating Value:	1051.9	BTU/SCF
Percent Sulfur of Fuel:	0.0	percent
Percent Ash of Fuel:	0.0	percent
Percent Carbon Content:	73.0	percent

Operating Detail

	Value
Operating Time in Hours per Day:	24
Operating Time in Days per Week:	7
Operating Time in Weeks per Year:	52
Operating Time in Hours per Year:	1597
Percent of Operation During Winter:	0
Percent of Operation During Spring:	25
Percent of Operation During Summer:	42
Percent of Operation During Fall:	33

Actual Pollutants

Pollutant	Amount	Unit of Measure	Calculation Method
Carbon Monoxide:	2.4	tons/y	Actual stack test
Formaldehyde:	0.57	tons/y	EPA emission factors (e.g., AP-42)
Nitrogen Dioxide:	43.2	tons/y	Continuous Emission Monitoring (CEMS)
Particulate Matter (10 microns or less):	5.285	tons/y	EPA emission factors (e.g., AP-42)
Particulate Matter (2.5 microns or less):	5.285	tons/y	EPA emission factors (e.g., AP-42)
Particulate Matter (total suspended):	5.285	tons/y	EPA emission factors (e.g., AP-42)
Sulfur Dioxide:	0.4	tons/y	Continuous Emission Monitoring (CEMS)
Volatile Organic Compounds (VOC):	1.682	tons/y	EPA emission factors (e.g., AP-42)

Subject Item Comments

Print Close

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	135	MW
What is the higher heating value (HHV) of the fuel?	1,052	Btu/scf
What is the estimated actual annual MWhs output?	127,680	MWhs
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 3815 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	70	days
Number of days the boiler operates (t_{plant})	70	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.30	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.10	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	700	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	15.84	ft^3/min-MMBtu/hour

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	603.1	2018 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0361	$/kWh			* $0.0361/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	-	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	-	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1025	Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	183	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	1,182,600	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		127,680	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.03		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.108	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	946	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	65.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	35.17	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	16.63	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.81		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2897.6	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	5.3	/hour	
Residence Time	1/V_{space}	0.1896	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.15		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.0493	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	549.39	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	3	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	62	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	3	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	1.9	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	284	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	14	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	47	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	6	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,200	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	765.67	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$15,373,721	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$106,805 in 2018 dollars
Indirect Annual Costs (IDAC) =	$1,288,207 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$1,395,011 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$76,869 in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$1,745 in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$26,142 in 2018 dollars
Annual Catalyst Replacement Cost =		$2,049 in 2018 dollars
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	
	$B_{MW} \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
	$(Q_B/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
Direct Annual Cost =		$106,805 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$1,426 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,286,780 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,288,207 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,395,011 per year in 2018 dollars
NOx Removed =	17 tons/year
Cost Effectiveness =	$83,887 per ton of NOx removed in 2018 dollars

Xcel Energy

Cunningham Station

Turbine	Interest Rate:		5.50%	
Unit 4	SCR Period:		20	years
	Water Injection Period:		15	years
Base: Dry Low NO_X				
NO_X ppm:		25	ppm	<-- With Power Augmentation (Permitted)
NO_X lb/hr:		59.48	lb/hr	<-- From 2016 Emission Inventory Report
NO_X tpy:		84.70	tpy	<-- From 2016 Emission Inventory Report
Water Injection				
NO_X guarantee:		12%	Control Eff.	<-- Vendor Information (Decrease by 3 ppm)
NO_X lb/hr:		52.34	lb/hr	
NO_X tpy:		74.54	tpy	
Total Equipment Cost[2]	$	2,030,510		<-- Vendor Quote with 10% Contingency
Indirect and Direct Installation Costs[3]	$	290,363		<--EPA Cost Manual Section 4.2
Allowance Funds During Construction[4]	$	464,175		<--EPA Cost Manual Section 4.2
Project Contingency[4]	$	586,005		<--EPA Cost Manual Section 4.2
Total Cap Investment	$	3,371,053		<-- Equipment, Installation, Allowance, and Contingency
Annualized TCI	$	282,087		<-- Based on interest rate, year and TCI
Annual O&M Costs[5]	$	57,764		<-- Electricity, Water, and Maintenance
Total Annual Costs	$	339,851		
Emissions Reduction:		10.16	tpy	
Cost Effectiveness:	**$**	**33,436.73**	**$/ton**	

1 From Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Timeline for Compliance (Docket ID No. EPA-HQ-OAR-2015-0500) Section 3.3.1, Corrected from 1999 to 2018 dollars based on CEPCI.

2 Total Capital Cost from Seimens April 2008 quotation. The cost includes instrumentation, sales tax and freight and is corrected from 2008 dollars to 2018 dollar using CEPCI ratios. 2018 CEPCI = 603.1, 2008 CEPCI = 575.4.

3 Estimates based on engineering knowledge and evaluation of costs for other equipment as specified in OAQPS Manual.

4 OAQPS Section 4.2 Chapter 2, Table 2.5

5 OAQPS Default, Section 4.2, Chapter 2, pages 2.45 and 2.46. Calculated based on water and energy usage from vendor.

SCR				
NO_X guarantee:		65%	Control %	<-- Assumed for SCR, AP-42 Section 3.1.4.3
NO_X lb/hr:		20.82	lb/hr	
NO_X tpy:		29.65	tpy	
Equipment Costs:	$	15,373,721		<-- EPA Cost Tool
Installation Engineering & Labor:	$	12,544,890		<-- Xcel Estimates
Total Cap Investment	$	27,918,611		<-- Equipment, Installation Engineering and Labor
Annualized TCI:	$	2,336,211		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	134,948		<-- EPA Cost Tool
Total Annual Costs:	$	2,471,158		
Emissions Reduction:		55.06	tpy	
Cost Effectiveness:	**$**	**44,885**	**$/ton**	

2016 Emission Inventory Data

Fuel Heating Value	1051.9	Btu/scf
Fuel Usage	2778	MMscf/yr
Heat Input	333.58	MMBtu/hr
Hours of Operation	2848	hrs/yr
Days of Operation	119	days/yr
NOx EF	0.18	lb/MMBtu
NOx Emissions	59.48	lb/hr
NOx Emissions	84.70	tpy

Facility Annual Emissions - Subject Item Submittal Review
Thursday, September 12, 2019

Agency ID: 604
Facility Name: Xcel Energy - Cunningham Station Power Plant
Organization Name: Southwestern Public Service Co dba Xcel Energy
Submittal Status: 2016 Submittal (Certified, Awaiting NMED Approval)

Subject Item ID: EQPT-7
Designation: 004
Description: Simple Cycle Gas Turbine
Type: Turbine
SCC: Internal Combustion Engines, Electric Generation, Natural Gas, Turbine
GHG Reporting: Reports GHG to EPA

Supplemental Parameters

	Amount	Unit of Measure
Fuel Type:	Natural Gas	
Input Materials Processed:	Natural Gas (INPUT)	
Materials Consumed:	2778.0	MM SCF
Fuel Heating Value:	1051.9	BTU/SCF
Percent Sulfur of Fuel:	0.0	percent
Percent Ash of Fuel:	0.0	percent
Percent Carbon Content:	73.0	percent

Operating Detail

	Value
Operating Time in Hours per Day:	24
Operating Time in Days per Week:	7
Operating Time in Weeks per Year:	52
Operating Time in Hours per Year:	2848
Percent of Operation During Winter:	10
Percent of Operation During Spring:	22
Percent of Operation During Summer:	25
Percent of Operation During Fall:	43

Actual Pollutants

Pollutant	Amount	Unit of Measure	Calculation Method
Carbon Monoxide:	2.9	tons/y	Actual stack test
Formaldehyde:	1.04	tons/y	EPA emission factors (e.g., AP-42)
Nitrogen Dioxide:	84.7	tons/y	Continuous Emission Monitoring (CEMS)
Particulate Matter (10 microns or less):	9.642	tons/y	EPA emission factors (e.g., AP-42)
Particulate Matter (2.5 microns or less):	9.642	tons/y	EPA emission factors (e.g., AP-42)
Particulate Matter (total suspended):	9.642	tons/y	EPA emission factors (e.g., AP-42)
Sulfur Dioxide:	0.9	tons/y	Continuous Emission Monitoring (CEMS)
Volatile Organic Compounds (VOC):	3.068	tons/y	EPA emission factors (e.g., AP-42)

Subject Item Comments

Print Close

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	135	MW
What is the higher heating value (HHV) of the fuel?	1,052	Btu/scf
What is the estimated actual annual MWhs output?	218,880	MWhs
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 3815 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	120	days
Number of days the boiler operates (t_{plant})	120	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.18	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.054	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)	700	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	15.84	ft^3/min-MMBtu/hour

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	603.1	2018 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0361	$/kWh			* $0.0361/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	-	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	-	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1025	Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	334	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	1,182,600	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		218,880	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.03		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.185	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	1621	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	42.03	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	34.07	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.88		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	5285.4	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	5.2	/hour	
Residence Time	1/V_{space}	0.1920	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.15		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.8	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.1029	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	1,015.06	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	6	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	62	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	6	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	2.5	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	287	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	16	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	56	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,600	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	765.67	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$15,373,721	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$133,161 in 2018 dollars
Indirect Annual Costs (IDAC) =	$1,288,567 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$1,421,728 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$76,869 in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$3,574 in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$44,815 in 2018 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$7,903 in 2018 dollars
Direct Annual Cost =		$133,161 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$1,786 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,286,780 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,288,567 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,421,728 per year in 2018 dollars
NOx Removed =	34 tons/year
Cost Effectiveness =	$41,725 per ton of NOx removed in 2018 dollars

Direct Costs

Line Item	C/RWIP	Type	Description	Company (Optional)	Qty	Unit of Measure	Unit Cost	Taxable	Escalation Overwrite % (Optional)	Sub-Total inc Tax	Escalated Total	P-Load	S-Load	Assumptions & Comments (Optional)	Lead Time (Optional)
DIR-PO-02	CWIP	Material	Allen Bradley PLC		1	each	$ 55,000.00	Yes		$ 57,819	$ 57,819	Y	Y		
DIR-PO-03	CWIP	Material	Electric hoist/monorail		1	each	$ 60,000.00	Yes		$ 63,075	$ 63,075	Y	Y		
DIR-PO-04	CWIP	Material	Physical flow modeling		1	lot	$ 40,000.00	Yes		$ 42,050	$ 42,050	Y	Y		
DIR-PO-05	CWIP	Material	10,000 gal aqueous ammonia storage tank with accessories		1	each	$ 389,890.00	Yes		$ 409,872	$ 409,872	Y	Y		
DIR-PO-06	CWIP	Service	Contract Labor for installation		1	lot	$12,000,000.00	Yes		$ 12,615,000	$ 12,615,000	Y	N		
DIR-PO-07															
DIR-PO-08															
DIR-PO-09															
DIR-PO-10															
DIR-PO-11															
DIR-PO-12															
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DIR-PO-27															
DIR-PO-28															
DIR-PO-29															
DIR-PO-30															

Line Item	C/RWIP	Type	Description	Unassigned $
DIR-PO-02	CWIP	Material	Allen Bradley PLC	$ 57,818.75
DIR-PO-03	CWIP	Material	Electric hoist/monorail	$ 63,075.00
DIR-PO-04	CWIP	Material	Physical flow modeling	$ 42,050.00
DIR-PO-05	CWIP	Material	10,000 gal aqueous ammonia stor	$ 409,871.86
DIR-PO-06	CWIP	Service	Contract Labor for installation	$ 12,615,000.00

Xcel Direct Labor

Line Item	C/RWIP	Role (Select "Other" if not listed)	Job Title (Optional)	Crew Size	Unit Hours	Total Hours	1.5x Pay %	2.0x Pay %	Regular Time	Unit of Measure	Default Rate (Straight Time)	Overwrite Rate	Escalation Overwrite % (Optional)	Sub-Total	Escalated Total	Assumptions & Comments	Lead Time (Optional)
DIR-LAB-0	CWIP	Electrician	Electrician Journeyman	3	120	360	5%		95%	hrs	$ 56.70			$ 20,748	$ 20,748		
DIR-LAB-0	CWIP	Instrument_Tech	Instrument Journeyman	2	120	240	5%		95%	hrs	$ 56.70			$ 13,832	$ 13,832		
DIR-LAB-0	CWIP	Mechanic	Maintenance Mechanic Journe	2	240	480	5%		95%	hrs	$ 56.70			$ 27,665	$ 27,665		
DIR-LAB-04							5%		95%	hrs							
DIR-LAB-05									100%	hrs							
DIR-LAB-06									100%	hrs							
DIR-LAB-07									100%	hrs							
DIR-LAB-08									100%	hrs							
DIR-LAB-09									100%	hrs							
DIR-LAB-10									100%	hrs							
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DIR-LAB-24									100%	hrs							
DIR-LAB-25									100%	hrs							
DIR-LAB-26									100%	hrs							
DIR-LAB-27									100%	hrs							
DIR-LAB-28									100%	hrs							
DIR-LAB-29									100%	hrs							
DIR-LAB-30									100%	hrs							
						1080					**Total**			**$ 62,245**	**$ 62,245**		

Line Item	C/RWIP	Description	Unassigned
DIR-LAB-01	CWIP	Electrician Journeyman	$ 20,748.43
DIR-LAB-02	CWIP	Instrument Journeyman	$ 13,832.29
DIR-LAB-03	CWIP	Maintenance Mechanic Journeymn	$ 27,664.58
		Sub-Total	**$ 62,245.30**

Indirect Estimating

Estimate Indirect Labor Costs | Estimate Indirect Labor Costs as a Percentage of Total Cost

Default %	Overwrite %	Escalation Overwrite % (Optional)	Sub-Total	Escalated Total	Assumptions & Comments	Lead Time (Optional)
5.00%	5.00%		$ 1,287,869	$ 1,287,869		
CWIP	100.00%		$ 1,287,869	$ 1,287,869		
RWIP			$ -	$ -		

Line Item	C/RWIP	Description	Unassigned
		Xcel Indirect Labor	$ 1,287,868.54
		Xcel Indirect Labor	$ -
		Sub-Total	**$ -**

Xcel Indirect Labor

Line Item	C/RWIP	Role (Select "Other" if not listed)	Job Title (Optional)	Qty	Unit of Measure	Default Rate	Overwrite Rate	Escalation Overwrite % (Optional)	Sub-Total	Escalated Total	Assumptions & Comments	Lead Time (Optional)
IND-LAB-0	CWIP	Project_Manager		1000	hrs	$ 99.29			$ 99,293	$ 99,293		
IND-LAB-0	CWIP	Engineer		1000	hrs	$ 84.86			$ 84,856	$ 84,856		
IND-LAB-03					hrs							
IND-LAB-04					hrs							
IND-LAB-05					hrs							
IND-LAB-06					hrs							
IND-LAB-07					hrs							
IND-LAB-08					hrs							
IND-LAB-09					hrs							
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IND-LAB-27					hrs							
IND-LAB-28					hrs							
IND-LAB-29					hrs							
IND-LAB-30					hrs							
IND-EXP-0	CWIP		Employee Expenses	1	lot				$ 23,645	$ 23,645		
IND-EXP-0	RWIP		Employee Expenses	1	lot				$ -	$ -		
				2000		**Total**	1		**$ 207,794**	**$ 207,794**		

Line Item	C/RWIP	Description	Unassigned
IND-LAB-01	CWIP	Project_Manager	$ 99,292.95
IND-LAB-02	CWIP	Engineer	$ 84,856.44
IND-EXP-01	CWIP	Employee Expenses	$ 23,644.78
IND-EXP-02	RWIP	Employee Expenses	$ -
		Sub-Total	**########## #**

Other Costs

Line Item	C/RWIP	Description	Qty	Unit of Measure	Unit Cost		Escalation Overwrite % (Optional)	Sub-Total	Escalated Total	Assumptions & Comments	Lead Time (Optional)
OTH-XXX-01											
OTH-XXX-02											
OTH-XXX-03											
OTH-XXX-04											
OTH-XXX-05											
OTH-XXX-06											
OTH-XXX-07											
OTH-XXX-08											
OTH-XXX-09											
OTH-XXX-10											
					Total			**$ -**	**$ -**		

Line Item	C/RWIP	Description	Unassigned
		Sub-Total	**$ -**

Overheads, Contingency and Loadings

Line Item	C/RWIP	Description	Qty	Unit of Measure	Calculated Costs	Overwrite Rate			Total Costs	Assumptions & Comments	Lead Time (Optional)
IND-OVH-0	CWIP	Contingency & Unknowns	1	lot	$ 2,596,517				$ 2,596,517		
IND-OVH-0	CWIP	Stores / Purchase Loads	1	lot	$ 878,257				$ 878,257		
IND-OVH-0	CWIP	E&S / Overheads	1	lot	$ 1,030,398				$ 1,030,398		
IND-OVH-0	RWIP	Contingency & Unknowns	1	lot	$ -				$ -		
IND-OVH-0	RWIP	Stores / Purchase Loads	1	lot	$ -				$ -		
IND-OVH-0	RWIP	E&S / Overheads	1	lot	$ -				$ -		
			Total		**$ 4,505,172**				**$ 4,505,172**		

Line Item	C/RWIP	Description	Unassigned
IND-OVH-01	CWIP	Contingency & Unknowns	$ 2,596,516.50
IND-OVH-02	CWIP	Stores / Purchase Loads	$ 878,257.22
IND-OVH-03	CWIP	E&S / Overheads	$ 1,030,397.86
IND-OVH-04	RWIP	Contingency & Unknowns	$ -
IND-OVH-05	RWIP	Stores / Purchase Loads	$ -
IND-OVH-06	RWIP	E&S / Overheads	$ -
		Sub-Total	**$ 4,505,171.58**

Grand Total **$ 30,470,337**

Costs from the "Air Pollution Control Technology Fact Sheet" for Selective Non-Catalytic Reduction	
Capital Cost ($/MW)	$ 25,000
O&M Cost ($/MW)	$ 5,000
Other Annualized Costs ($/MW/yr)	$ 1,000

	Unit 1	Unit 2	Notes
Boiler Rating (MW)	82	234	
Capital Cost	$ 2,050,000	$ 5,850,000	
O&M Cost	$ 410,000	$ 1,170,000	
Lifetime Annualized Costs	$ 1,640,000	$ 4,680,000	SNCR lifetime is assumed to be 20 years
Total Cost	$ 4,100,000	$ 11,700,000	Capital, O&M, and Other Annualized Costs
Annualized TCI	$343,085.25	$979,048.16	Amortized over 20 year with a 5.5% interest rate
Baseline Emissions (tpy)	142.50	588.90	2016 Emission Inventory Data
Control Efficiency (%)	24%	24%	AP-42 Section 1.4.4
Tons Controlled (tpy)	34.20	141.34	
Cost Per Ton ($/ton)	$10,031.73	$6,927.10	

From:	Worley, Kevin L
To:	Singleton,Kerwin, NMENV
Cc:	Jones, Mark, NMENV; Metcalf, Dean R; Bloomberg, Jon H; Lytal, Mark M; Nayares, Octavio P
Subject:	[EXT] Information Request - Cunningham Station Regional Haze
Date:	Monday, November 2, 2020 2:36:57 PM
Attachments:	Attachments.pdf

Mr. Singleton,

Please find attached a response to your question and clarifications for Cunningham Station as part of the NMED's Regional Haze project. Confidential information is being submitted under separate cover.

1. **NMED revised the cost estimate based on 2016 – 2018 average emissions and operating hours. The cost calculations assumed the default bank prime rate of 5.5%; however, the instructions indicate that the current bank prime rate should be used. Was the bank prime rate verified and/or documented during preparation of the analysis?** Xcel Energy is a utility regulated by the New Mexico and Texas Public Utility Commissions. We do not borrow money in a way that could accurately be represented by the bank prime rate. According to a recent agreement with NM PUC, see attached partial Uncontested Comprehensive Stipulation page 3 Section I.3, the "cost of capital" for Cunningham Station is 7.19%. This is not directly analogous to the prime rate, so we used 5.5%, which was the default in the EPA spreadsheet, to be conservative.
2. **The cost basis for water injection was based on a 2008 quote from Siemens, corrected to CEPI ratios. Any estimates older than 5 years will attract more scrutiny from other stakeholders, including the Federal Land Managers and EPA. Xcel should obtain an updated quote from the vendor for water injection.** We have received a "budgetary" estimate from Siemens Energy for water injection systems for Cunningham Units 3 and 4. Per unit, the equipment cost was $1.95 million and total cost including installation was $3.66 million. Installation costs are calculated using a spreadsheet that Xcel considers to be Confidential Business Information (CBI). We have included a summary of that spreadsheet detailing the total estimated costs of the water injection systems. An informational letter from Siemens Energy is also included as Confidential Business Information (CBI) on another email.
3. **The Xcel estimates for the costs associated with installation, engineering, and labor for an SCR system seem excessive, almost equivalent to the equipment costs. Additional information is required to justify this estimate.** Xcel has reviewed the costs with a vendor and using our estimation spreadsheets/model and determined that costs for installation should be lower. Xcel received a budgetary-level estimate from Siemens Energy for SCR controls on Cunningham Units 3 and 4. Per unit, the equipment cost was approximately $11.9 million and total cost including installation was approximately $21 million. An email from Siemens Energy is included with equipment costs. Installation costs are calculated using a spreadsheet that Xcel considers to be CBI. We have included a summary of that spreadsheet detailing the total estimated costs of the SCR systems.
4. **The calculations for Units 1 & 2 indicate an SCR life expectancy of 20 years, but the Cost Control spreadsheet (Data Inputs) indicates that the life expectancy for SCR on utility boilers is 30 years. NMED cost calculations account for this longer life expectancy for the boilers. Shouldn't the life expectancy for SCR on the turbines also be set at 30 years?** Both Cunningham Unit 1 and Unit 2 were constructed in the 1960s. They are approaching their end of life. Cunningham 1 will shut down before December 31, 2025. Cunningham 2 will shut down before December 31, 2028. The Unit 3 and 4 turbines are currently projected to shut down in 2040. With the engineering, construction, and installation, a 20-year life expectancy still allows for the flexibility necessary for such a long-term projection.
   Please explain why the lower end of the range for control efficiency by SCR (65%) was used in the analysis for the turbine retrofits. Because there has been no design work on SCRs for the turbines, an accurate estimate is not known. Xcel chose the low end of the range listed in AP-42 Section 3.1.4.3, 65%-90%. Because we haven't had a full design, Xcel believes that the upper range should not be used in this level of analysis. As a result, we believe using 80% as the estimate for the SCR

control efficiency would be best.

Kevin Worley
Xcel Energy | Responsible By Nature
Environmental Analyst
790 S. Buchanan St., Amarillo, TX 79101
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E: Kevin.L.Worley@xcelenergy.com

Partial Document

UNCONTESTED COMPREHENSIVE STIPULATION

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION FOR: (1) REVISION OF ITS RETAIL RATES UNDER ADVICE NOTICE NO. 282; (2) AUTHORIZATION AND APPROVAL TO SHORTEN THE SERVICE LIFE OF AND ABANDON ITS TOLK GENERATING STATION UNITS; AND (3) OTHER RELATED RELIEF,	)	**CASE NO. 19-00170-UT**
SOUTHWESTERN PUBLIC SERVICE COMPANY,	)	
APPLICANT.	)	

UNCONTESTED COMPREHENSIVE STIPULATION

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Exhibit B Tariffs
Exhibit C Depreciation Rates
Exhibit D Reconciliation Statement

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION FOR: (1) REVISION OF ITS RETAIL RATES UNDER ADVICE NOTICE NO. 282; (2) AUTHORIZATION AND APPROVAL TO SHORTEN THE SERVICE LIFE OF AND ABANDON ITS TOLK GENERATING STATION UNITS; AND (3) OTHER RELATED RELIEF,	)	**CASE NO. 19-00170-UT**
SOUTHWESTERN PUBLIC SERVICE COMPANY,	)	
APPLICANT.	)	

UNCONTESTED COMPREHENSIVE STIPULATION

The Signatories to this Uncontested Comprehensive Stipulation ("Stipulation"), which is dated as of January 13, 2020, are:

- Utility Division Staff of the New Mexico Public Regulation Commission ("Staff");
- Southwestern Public Service Company ("SPS");
- Occidental Permian Ltd. ("OPL");
- Federal Executive Agencies ("FEA");
- Louisiana Energy Services, LLC d/b/a URENCO USA ("LES");
- Hector H. Balderas, the Attorney General of the State of New Mexico ("AG");
- New Mexico Large Customer Group ("NMLCG");
- COG Operating LLC ("COG");
- Coalition for Clean Affordable Energy ("CCAE");

- Sierra Club ("SC");
- Western Resource Advocates ("WRA").

New Mexico Gas Company does not oppose this Stipulation. Roosevelt County Electric Cooperative, Inc., and Central Valley Electric Cooperative, Inc. take no position on this Stipulation. Accordingly, this Stipulation is uncontested.

The parties who are joining this Stipulation shall be referred to individually either as a Signatory or by the acronym assigned above, and collectively as the Signatories. The Signatories submit this Stipulation to the New Mexico Public Regulation Commission ("Commission") as representing a just and reasonable disposition of the issues related to this case consistent with the public interest. The Signatories request approval of this Stipulation and entry of findings, conclusions, and ordering paragraphs consistent with that approval.

On July 1, 2019, in accordance with the Public Utility Act ("PUA"), SPS filed its application with the Commission seeking authority to revise its base rates. SPS's application requested that the Commission: authorize SPS to increase its base rate charges for the New Mexico retail jurisdiction by $50,778,291. SPS also requested that the Commission: authorize SPS to modify the service life of Tolk Generating Station Units 1 and 2 ("Tolk") to 2032 and approve abandonment of Tolk during that year, and grant all other approvals, authorizations, and variances that the Commission determines are necessary for SPS to effectuate and implement the relief granted in this case.

By this Stipulation, the Signatories agree to resolve all issues among them related to SPS's application, and agree as follows:

I. Agreement as to Base Rate Increase

SPS's Initial Application sought a base rate revenue requirement increase of $50,778,291. Several parties recommended base rate revenue requirement increases ranging from $21,947,452 to $29,903,958. The Signatories agree that SPS should be authorized to implement an increase in base rate revenues of $31,000,000 in its New Mexico retail service area. The stated cost of service components associated with the increase (including the items required to be provided pursuant to Ordering Paragraph G of the Procedural Order in this matter) are as follows:

1. The return on equity is 9.45%.
2. The capital structure consists of 54.77% common equity and 45.23% long-term debt.
3. The tax-unadjusted weighted average cost of capital is 7.19%.
4. Depreciation rates are provided in Exhibit C. The incremental increase in depreciation expense relative to current rates is $8,067,214.
5. Rate case expenses for this rate case of $1,200,000, to be amortized over one year.
6. The annual amortization of SPS's Z2 expense is $520,490.
7. The annual amortization of SPS's NOx expenses deferred from prior years is $34,890.
8. The revenue requirement for the Hale Wind Project ("Hale") is $26,055,632. The total company gross plant-in-service for Hale in this case is $700,246,760. That equates to $1,465 per kW installed (total company), which is less than the $1,675 per kW installed (total company) cap required by the Order in Case No. 17-00044-UT.

The increase by class and revenue proof is reflected in Exhibit A to this Stipulation ("Exhibit A"). The rate tariffs for the increase and all other stipulated tariff changes are provided in Exhibit B to this Stipulation ("Exhibit B"). Depreciation rates are provided in Exhibit C to this Stipulation ("Exhibit C"). Reconciliation statements are provided in Exhibit D to this Stipulation ("Exhibit D").

The stipulated base rate revenue increase is not associated with any specific calculation involving any of the stated cost of service components herein, or approval or disapproval of any

Southwestern Public Service Company
SPS JCOSS NM Electric: 2019 Rate Case - Case No 19-00170-UT_Settlement
12 Months Ending March 2019
Deficiency

Line No.	SPS - 300 - Deficiency RR Method (1yr)	SPS NM Electric Retail
1	Cost of Long-Term Debt	4.44%
2	Cost of Common Equity	9.45%
3	Ratio of Long Term-Debt	45.23%
4	Ratio of Common Equity	54.77%
5	Weighted Cost of Long-Term Debt	2.01%
6	Weighted Cost of Common Equity	5.18%
7	Federal Tax Rate	21.00%
8	State Tax Rate	1.41%
9	Weighted Average Cost of Capital	7.19%
10		
11	**Revenue Deficiency**	
12	Cost of Sales	18,588,643
13	O&M	133,272,980
14	Depreciation and Amortization Expense	73,299,136
15	TOTI	17,282,587
16		
17	Rate Base	1,270,951,362
18	Weighted Cost of Debt	2.01%
19	Interest Deduction	25,546,122
20		
21	Schedule M	(78,102,782)
22	Deferred Taxes	12,281,432
23	ITC Amortized	(13,930)
24		
25	Weighted Average Cost of Capital	7.19%
26	Authorized Earnings	91,381,403
27		
28	State Taxable Income	(12,267,502)
29	State Tax Rate	1.41%
30	State Tax Expense	(172,432)
31		
32	Section 199 Deduction	
33	Federal Taxable Income	(12,095,070)
34	Federal Tax Rate	21.00%
35	Federal Tax Expense	(2,539,965)
36		
37	Total Tax Expense	9,555,105
38	Federal Gross up factor	1.283869
39	Gross Total Tax Expense	12,267,502
40		

Southwestern Public Service Company
SPS JCOSS NM Electric: 2019 Rate Case - Case No 19-00170-UT_Settlement
12 Months Ending March 2019
Deficiency

Line No.	SPS - 300 - Deficiency RR Method (1yr)	SPS NM Electric Retail
41		
42	Gains/Losses	
43		
44	Operating Deductions	254,710,847
45	Revenue Credits	(42,394,408)
46	Total Revenue Requirement	303,697,842
47		
48	Revenue at Present Rates	(272,697,842)
49		
50	**Revenue Deficiency/Excess**	**31,000,000**

Water Injection Information Letter

CONFIDENTIAL INFORMATION

Submitted under other cover

Xcel Estimate Calculation Summary

Water Injection

Units 3 and 4

Xcel Energy®
RESPONSIBLE BY NATURE™

Engineering and Construction
Capital Project Estimate

Project Name	C3 Water Injection
Project Number	
Estimator	Mark Lytal
Estimate Revision #	
Date of Estimate	
Region	SPS
Plant	Cunningham
Unit	3
Estimate Type	Feasibility (Level 1)
Project Cost Band	>$1m
Indirect Labor Effort	High
Date of Cost Data	
Project Start Date	
Project In-Service Date	
Project Completion Date	
Years Until Project Starts	0

Project Calculations	Default	Overwrite
Annual Escalation	2.82%	
Overhead Rate	3.50%	
Contingency	25.00%	15.00%
Purchase Loads	1.00%	
Stores Loads	4.75%	
Tax Rate	5.13%	
Expenses to Indirect Labor	12.84%	

Cost Breakdown Structure	CWIP	RWIP	Total
Direct Costs	$ 2,785,813	$ -	$ 2,785,813
Xcel Direct Labor	$ 62,245	$ -	$ 62,245
Xcel Indirect Labor	$ 103,897	$ -	$ 103,897
Other Costs	$ -	$ -	$ -
Overheads, Contigency & Loadings	$ 711,895	$ -	$ 711,895
Total	**$ 3,663,850**	**$ -**	**$ 3,663,850**

Xcel Energy®
RESPONSIBLE BY NATURE™

Engineering and Construction
Capital Project Estimate

Project Name	C4 Water Injection
Project Number	
Estimator	Mark Lytal
Estimate Revision #	
Date of Estimate	
Region	SPS
Plant	Cunningham
Unit	4
Estimate Type	Feasibility (Level 1)
Project Cost Band	>$1m
Indirect Labor Effort	High
Date of Cost Data	
Project Start Date	
Project In-Service Date	
Project Completion Date	
Years Until Project Starts	0

Project Calculations	Default	Overwrite
Annual Escalation	2.82%	
Overhead Rate	3.50%	
Contingency	25.00%	15.00%
Purchase Loads	1.00%	
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Overheads, Contigency & Loadings	$ 711,895	$ -	$ 711,895
Total	**$ 3,663,850**	**$ -**	**$ 3,663,850**

SCR Information Email

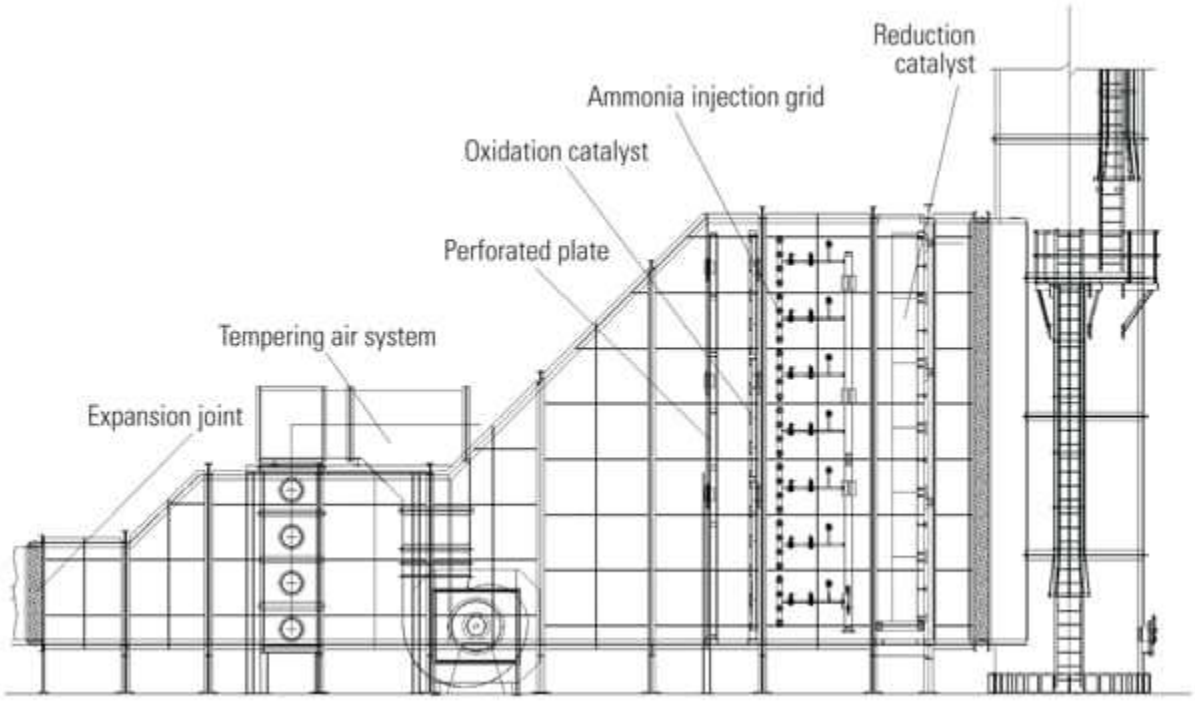
Worley, Kevin L

Subject: FW: Cunningham SCR's

From: Cunningham, Austin <austin.cunningham@siemens.com>
Sent: Monday, October 12, 2020 1:37 PM
To: Lytal, Mark M <Mark.Lytal@XCELENERGY.COM>
Subject: RE: Cunningham SCR's

Hi Mark,

Hope you had a good weekend and sorry for the delay. I had a few more conversations and hopefully the following will work for what you need. The picture below is what would be provided:



Of course, you could not just drop this in and run the unit. Up front engineering work would be needed including review of the electrical systems, analysis of the existing BOP, etc. The number I received for above would be approximately $10M (per unit) with the engineering and other work being in addition to that.

How does that line up with what you provided initially?

Thanks and let me know what you think!

Austin Cunningham
Regional Account Manager

8600 North Royal Lane
Irving, TX 75063, USA
Cell (469) 588-5550

austin.cunningham@siemens.com
siemens-energy.com



Xcel Estimate Calculation Summary

SCR

Units 3 and 4

Engineering and Construction
Capital Project Estimate

Project Name	C3 SCR
Project Number	
Estimator	Doug Taylor
Estimate Revision #	
Date of Estimate	
Region	SPS
Plant	Cunningham
Unit	3
Estimate Type	Feasibility (Level 1)
Project Cost Band	>$1m
Indirect Labor Effort	High
Date of Cost Data	
Project Start Date	
Project In-Service Date	
Project Completion Date	
Years Until Project Starts	0

Project Calculations	Default	Overwrite
Annual Escalation	2.82%	
Overhead Rate	3.50%	
Contingency	25.00%	15.00%
Purchase Loads	1.00%	
Stores Loads	4.75%	
Tax Rate	5.13%	
Expenses to Indirect Labor	12.84%	

Cost Breakdown Structure	CWIP	RWIP	Total
Direct Costs	$ 18,862,001	$ -	$ 18,862,001
Xcel Direct Labor	$ 62,245	$ -	$ 62,245
Xcel Indirect Labor	$ 207,794	$ -	$ 207,794
Other Costs	$ -	$ -	$ -
Overheads, Contigency & Loadings	$ 4,478,144	$ -	$ 4,478,144
Total	**$ 23,610,184**	**$ -**	**$ 23,610,184**

Engineering and Construction
Capital Project Estimate

Project Name	C4 SCR
Project Number	
Estimator	Doug Taylor
Estimate Revision #	
Date of Estimate	
Region	SPS
Plant	Cunningham
Unit	4
Estimate Type	Feasibility (Level 1)
Project Cost Band	>$1m
Indirect Labor Effort	High
Date of Cost Data	
Project Start Date	
Project In-Service Date	
Project Completion Date	
Years Until Project Starts	0

Project Calculations	Default	Overwrite
Annual Escalation	2.82%	
Overhead Rate	3.50%	
Contingency	25.00%	15.00%
Purchase Loads	1.00%	
Stores Loads	4.75%	
Tax Rate	5.13%	
Expenses to Indirect Labor	12.84%	

Cost Breakdown Structure	CWIP	RWIP	Total
Direct Costs	$ 18,862,001	$ -	$ 18,862,001
Xcel Direct Labor	$ 62,245	$ -	$ 62,245
Xcel Indirect Labor	$ 207,794	$ -	$ 207,794
Other Costs	$ -	$ -	$ -
Overheads, Contigency & Loadings	$ 4,478,144	$ -	$ 4,478,144
Total	**$ 23,610,184**	**$ -**	**$ 23,610,184**

From:	Worley, Kevin L
To:	Singleton,Kerwin, NMENV
Cc:	Jones, Mark, NMENV; Metcalf, Dean R; Bloomberg, Jon H; Lytal, Mark M; Nayares, Octavio P
Subject:	[EXT] RE: Information Request - Cunningham Station Regional Haze
Date:	Monday, January 25, 2021 4:08:28 PM

Mr. Singleton,

The costs do not included incremental O&M.

Kevin Worley
Xcel Energy | Responsible By Nature
Environmental Analyst
790 S. Buchanan St., Amarillo, TX 79101
P: 806.378.2185 **C:** 806.418.3834 **F:** 806.378.2517
E: Kevin.L.Worley@xcelenergy.com

From: Singleton,Kerwin, NMENV <Kerwin.Singleton@state.nm.us>
Sent: Tuesday, January 19, 2021 11:31 AM
To: Worley, Kevin L <kevin.l.worley@xcelenergy.com>
Cc: Jones, Mark, NMENV <Mark.Jones@state.nm.us>; Metcalf, Dean R <Dean.Metcalf@XCELENERGY.COM>; Bloomberg, Jon H <Jon.H.Bloomberg@xcelenergy.com>; Lytal, Mark M <Mark.Lytal@XCELENERGY.COM>; Nayares, Octavio P <Octavio.P.Nayares@xcelenergy.com>
Subject: RE: Information Request - Cunningham Station Regional Haze

EXTERNAL - STOP & THINK before opening links and attachments.

Mr. Worley,
I am following up on my email sent on 08 Dec. 2020. We are working towards finalizing our four-factor analyses, so we would appreciate a response by the end of the month.
Thank you,

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505
(Office) 505.476.4350
(Mobile) 505.699.3371
kerwin.singleton@state.nm.us
www.env.nm.gov

From: Singleton,Kerwin, NMENV
Sent: Tuesday, December 8, 2020 4:13 PM
To: Worley, Kevin L <kevin.l.worley@xcelenergy.com>
Cc: Jones, Mark, NMENV <Mark.Jones@state.nm.us>; Metcalf, Dean R <Dean.Metcalf@XCELENERGY.COM>; Bloomberg, Jon H <Jon.H.Bloomberg@xcelenergy.com>; Lytal, Mark M <Mark.Lytal@XCELENERGY.COM>; Nayares, Octavio P <Octavio.P.Nayares@xcelenergy.com>
Subject: RE: Information Request - Cunningham Station Regional Haze

Mr. Worley,
Thank you for the information provided in this most recent submittal; these figures will be incorporated into our cost calculations. Regarding the O&M costs previously provided, do those costs reflect the incremental O&M costs, i.e., costs above and beyond already incurred?
Regards,

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505
(Office) 505.476.4350
(Mobile) 505.699.3371
kerwin.singleton@state.nm.us
www.env.nm.gov

From: Worley, Kevin L
To: Baca, Michael, ENV; Rogers, Chris; Snyder, Karalee D; Olson, Kirby, ENV; Jones, Mark, ENV
Cc: Sidner, Bob, ENV; Miller, Kenneth, ENV
Subject: [EXTERNAL] RE: Regional Haze - Cunningham Station 4FA
Date: Tuesday, July 18, 2023 1:12:54 PM
Attachments: image001.png
image002.png

CAUTION: This email originated outside of our organization. Exercise caution prior to clicking on links or opening attachments.

Here are our answers to question 5.

5.a. O&M Costs – This number for each unit is the annual average for the current 5 year budget cycle. I split the number out, since I wasn't sure whether fuel should be included or not.

Cunningham 3	
Average Total O&M	$ 4,642,561
Average Fuel Expense	$ 2,446,749
Average Fixed Fuel Expense	$ 408,585
Average Fixed O&M	$ 1,787,227

Cunningham 4	
Average Total O&M	$ 5,378,726
Average Fuel Expense	$ 3,107,972
Average Fixed Fuel Expense	$ 525,001
Average Fixed O&M	$ 1,745,753

5.b. – Overhaul Costs. The average for the currently planned overhauls (2025, 2026, and 2027)

Unit 3 – $136,500

Unit 4 – $180,808

In addition, hot gas path inspections are planned for 2023 (Unit 4 – $8.7 million) and 2024 (Unit 3 – $6.7 million). The next one of those will possibly occur in 2030 or so.

Appendix E: Coordination and Outreach Supporting Documentation

E.1 Coordination with Local Jurisdictions and Other States

Supporting documentation for New Mexico Environment Department (NMED) coordination with local jurisdictions and other states is provided below. The following documents are included in this section (in reading order):

- NMED Communication to Texas Commission for Environmental Quality (TCEQ) on Draft SIP Revision Process:
    - NMED Comments and Questions (4/24/20)
    - NMED Comments and Questions (1/08/21)
    - NMED Additional Comments (2/2/21)
- NMED Notice to State and Local Agencies of available NMED draft Regional Haze SIP [FLM Review Version]
    - NMED Email to Contiguous States and City of Albuquerque - EHD (6/20/24)
- Contiguous State Comments to NMED
    - Arizona Department of Environmental Quality (7/18/24)
    - TCEQ (7/16/2024)

NEW MEXICO
ENVIRONMENT DEPARTMENT

Michelle Lujan Grisham
Governor

Howie C. Morales
Lt. Governor

525 Camino de los Marquez, Suite 1
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James C. Kenney
Cabinet Secretary

Jennifer J. Pruett
Deputy Secretary

April 24, 2020

Ms. Tonya Baer
Deputy Director, Air Quality Division
Texas Commission on Environmental Quality
P.O. Box 13087
Austin, TX 78711-3087
tonya.baer@tceq.texas.gov

Subject: New Mexico Environment Department (NMED) Comments and Questions for TCEQ on Regional Haze Consultation

Dear Deputy Director Baer,

Thank you for the opportunity to review Texas Commission on Environmental Quality's (TCEQ's) April 8th presentation, "Results of Photochemical Modeling for Regional Haze for Consultation with New Mexico." NMED and the City of Albuquerque/Bernalillo County (which is a separate air quality jurisdiction from NMED) have developed initial questions and comments on the presentation, including emission inventory development; screening approaches used in the analysis; selection of additional potential controls; air-related issues specific to the Permian Basin; and more technical questions on model performance and accuracy. NMED appreciates your review and evaluation of the questions and looks forward to discussing these items with the TCEQ Regional Haze team.

Emissions Inventory for Modeling

NMED has been working with the Western Regional Air Partnership (WRAP) on developing inventories for regional haze planning and other technical aspects of our regional haze SIP planning. Information on the WRAP development of emission inventories for modeling is available on the WRAP work group site at https://www.wrapair2.org/RHP_InvMod.aspx. Over several years, TCEQ and NMED worked with EPA on developing the 2016 collaborative regional haze modeling inventory platform.

NMED would like a better understanding of how TCEQ developed the regional haze base case and future year projections used in the analysis and specifically how they differ from EPA's inventories for the 2016 and 2028 platforms. Please describe the inventory that was used for New Mexico and how these emissions affect the Class I areas in New Mexico and Texas. Please also discuss what source sector or county level changes in emissions were projected for Texas and New Mexico in the inventories.

Screening Approaches

As part of a robust stakeholder outreach process, NMED performed targeted public outreach and meetings to explain the screening and selection process. Questions remain regarding how the screening

and selection process was conducted by TCEQ. To assist in NMED's understanding of this process, please detail how TCEQ screened the sources that were required to perform a four-factor analysis, including:

1. What data sets were used to determine the Q/d threshold to select sources for four-factor analysis, and are these data sets available to NMED? What factors did TCEQ consider for selecting sources on a per pollutant basis, rather than combined emissions of SO_2 and NO_x?
2. What percentage of total NO_X and SO_2 emissions are captured with a Q/d>5?
3. Were emissions from minor and area sources considered in determining what sources are subject to a four-factor analysis?
4. Will TCEQ post four-factor analyses on its website for review?

WRAP recently completed preliminary Weighted Emissions Potential (WEP) and Area of Influence (AOI) results for Class I areas in the Western United States. NMED would like to discuss these results with TCEQ to compare methods and results to TCEQ's analysis. The WRAP results may be accessed on their Technical Support System (TSS) at https://views.cira.colostate.edu/tssv2/.

Additional Potential Controls Selection and Consultation

NMED has been working with the sources conducting the four factor analysis to develop potential additional control scenarios to be modeled for future impacts on Class I areas. Additionally, WRAP is currently working on modeling the 2028 future year conditions with and without potential control scenarios. NMED and the City of Albuquerque/Bernalillo County have shared with EPA Region 6 a summary of the Potential Additional Controls (PAC) that are being tested in WRAP's modeling. In the future, WRAP plans to run at least one additional control scenario to look at PACs for 2028 under the Regional Haze SIP.

NMED would like to discuss the potential controls TCEQ and NMED are considering for four-factor sources and how those potential controls will affect Class I areas in New Mexico, especially sites near the Texas-New Mexico border. In addition, NMED would like to understand what additional NO_X and SO_2 controls are being evaluated for those anthropogenic sources that impact visibility at Salt Creek and other Class I areas in New Mexico.

Permian Basin

Oil and gas sources and related emissions in the Permian Basin have been increasing in the last several years, resulting in significant NO_x and SO_2 emissions from the increased production and development. TCEQ's presentation showed impacts from Texas on Class I areas in New Mexico, particularly in the vicinity of the Permian Basin; however, it did not appear as if any oil and gas facilities were part of the four-factor analysis.

In our preliminary modeling evaluations, ammonium sulfate is a primary contributor to anthropogenic visibility impairment. NMED is interested in learning more about the sources of sulfate emissions in the Permian Basin that may be contributing to the impairment, such as information in TCEQ inventories from flaring and how this data has been integrated into the project. Are strategies being considered to reduce flaring emissions of SO_2 in the Permian Basin to address regional haze?

The Salt Creek Wilderness area in New Mexico shows monitored and modeled progress quite a bit above the URP glidepath on several modeling scenarios for EPA, TCEQ, and WRAP. Are there other sites in the West that have this issue? Perhaps this is a case where we need to perform further evaluation of the sources impacting visibility at this area.

The impacts at the Carlsbad Caverns Class I area, which is 40 km northeast of Guadalupe Mountains National Park, was not discussed in the TCEQ presentation. Since these two Class I areas are on the border with Texas and New Mexico, NMED believes that the states should discuss these two sites and what sources may be contributing to visibility impairment. These Class I areas are using the same IMPROVE monitoring data.

Modeling Performance and Comparisons

Several performance issues have been observed in the first stage of EPA modeling for regional haze. It seems that the normalized mean error in the EPA version of the modeling for SO_4 in the southwest is 67%. EPA's Technical Support Document states that "Further improvements in emissions inputs, boundary conditions, and model chemistry may help improve model performance in specific regions, particularly in the Northern Rockies and Plains, Northwest, West, and the Southwest." Has TCEQ worked to improve the model performance for their estimations of impacts on Class I areas? If so, has TCEQ modeling shown better performance? Is a model performance evaluation report for nitrates and sulfates available for NMED review?

Information on the WRAP regional modeling, including a white paper and a draft document on source apportionment, are available on the WRAP Regional Technical Operations Workgroup website at https://www.wrapair2.org/RTOWG.aspx. How did TCEQ decide on source apportionment categories for their modeling?

Consultation

NMED and the City of Albuquerque/Bernalillo County are currently working together on the SIP development process. NMED has a dedicated website to the development of the 2021 regional haze SIP at https://www.env.nm.gov/air-quality/reg-haze/.

The WRAP is providing more detailed information in the coming months on what potential contributions New Mexico sources may have on Texas Class I areas. NMED would like to continue the consultation process with TCEQ and the EPA regional office as more of this information is completed and delivered to the WRAP TSS Site at https://views.cira.colostate.edu/tssv2/. The WRAP TSS site will provide modeling and analysis information for Western States and is being used to help WRAP states develop their 2021 SIPs. The WRAP has various work groups dedicated to regional haze including the WRAP Coordination and Glidepath workgroup accessible here: https://www.wrapair2.org/RHP_coordination.aspx.

WRAP has developed a specific guidance document titled *Communication Framework for Regional Haze* that includes suggestions and a format for consultation and coordination amongst states. The document is available on the WRAP website at https://www.wrapair2.org/pdf/WESTAR-WRAP_Communication_Framework.pdf and is used as a guide to help agencies communicate early and frequently with the states and Federal Land Managers (FLMs). Please see in particular Chapter 3, "Regional Haze Rule Consultation Requirements."

NMED will likely have additional questions. We look forward to working with TCEQ on these items and staying in close communication as both agencies move forward. This is especially critical given that the two states share Class I areas near the border. It may be valuable to work with EPA Region 6 on the main areas of the consultation, such as emissions reductions necessary to make reasonable progress, since both states fall within the same EPA region.

NMED also recognizes that TCEQ will have questions and may also have consultation needs with other WRAP states or tribes, and it may be possible to discuss some of these items, including the modeling, on a collective basis with WESTAR-WRAP.

NMED is looking forward to working closely with TCEQ to ensure a robust, ongoing consultation process as we move forward with the evaluation of potential additional controls and Regional Haze SIP development. This will help ensure that our states fulfill their responsibility to take prudent action to reduce visibility impacts at Class I areas. NMED is eager for a new level of cooperation on other state initiatives aimed at improving air quality in the areas near the New Mexico/Texas border.

Please don't hesitate to contact Mark Jones, mark.jones@state.nm.us, or Kerwin Singleton, kerwin.singleton@state.nm.us with any questions.

We look forward to meeting with your staff to discuss these matters and a process to move the collaboration forward.

Sincerely,

Sandra Ely
Division Director
Environmental Protection Division

Cc: Donna Huff, Director, Air Quality Division, TCEQ
Walker Williamson, Senior Project Manager, Air Quality Division, TCEQ
Liz Bisbey-Kuehn, Bureau Chief, Air Quality Bureau, NMED
Kerwin Singleton, Planning Section Chief, Air Quality Bureau, NMED
Mark Jones, Environmental Analyst – Advanced, Air Quality Bureau, NMED

NEW MEXICO
ENVIRONMENT DEPARTMENT

525 Camino de los Marquez, Suite 1
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Michelle Lujan Grisham
Governor

Howie C. Morales
Lt. Governor

James C. Kenney
Cabinet Secretary

Jennifer J. Pruett
Deputy Secretary

January 8, 2021

Ms. Tonya Baer
Director, Air Quality Division
Texas Commission on Environmental Quality (TCEQ)
P.O. Box 13087
Austin, TX 78711-3087
tonya.baer@tceq.texas.gov

Re: New Mexico Environment Department (NMED) Comments and Questions on TCEQ's proposed 2021 Regional Haze State Implementation Plan Revision for the Second Planning Period (Project No. 2019-112-SIP-NR)

Dear Director Baer,

NMED submitted a letter to TCEQ on April 24, 2020, "New Mexico Environment Department (NMED) Comments and Questions for TCEQ on Regional Haze Consultation," which requested a robust, ongoing consultation process as we move forward with the evaluation of potential additional controls and Regional Haze State Implementation Plan (SIP) development. As part of this process, NMED has reviewed TCEQ's proposed 2021 Regional Haze SIP Revision (Project No. 2019-112-SIP-NR). NMED comments on the 2021 Regional Haze SIP revision are detailed below and will also be submitted via eComments:

1. Overarching: NMED agrees in principle with the National Park Service (NPS) consultation document, "Regional Haze Consultation Documentation for NPS/Texas; October 8, 2020," stating that many of the emission reduction opportunities considered by TCEQ may be more affordable than presented and that the cumulative benefit of emission reductions over time will be necessary to achieve the Clean Air Act and Regional Haze Rule goals. NMED also generally agrees with the NPS, as well as the U. S. Forest Service (USFS) formal comments submitted on the proposal and evaluations that TCEQ should evaluate additional sources and should implement emission controls that substantively address the need for incremental improvement. TCEQ's presentation of modeling results showed visibility impacts from Texas on Class I Areas in New Mexico, particularly in the vicinity of the Permian Basin.

2. Commissioners Page 3: "Consultation with other states and the FLMs is ongoing and because other states are at different stages of development of their Regional Haze State Implementation Plan (SIP) revisions, this proposal does not include a complete record of consultation. Documentation of additional consultation after July 31, 2020 will be included at adoption." NMED would like to continue consultation calls with TCEQ as we review and interpret our modeling results and potential additional control strategies through March of 2021.

3. Page ES-1: What percentage of the overall NOx and SO2 emissions does the Q/D = 5 represent?

4. Pages 3-4: Consultation Summary 3.4.5 Federal Land Managers: NPS requested that TCEQ look at fifteen (15) additional sources that have a Q/d >5 that were not included in the analysis, asked why Bandelier National Monument (BAND), Big Bend National Park (BIBE), and Carlsbad Caverns (GUMO) were not included in the SO_2 Area of Influence (AOI) analysis, and that Salt Creek Wilderness Area (SACR) should have been included for both pollutants. See Appendix A. Were these concerns addressed in the proposed SIP revision? NPS also encouraged TCEQ to consider expanding their engine rule for ozone non-attainment areas to the Permian Basin as an effective method of addressing oil and gas (O&G) area source emissions that are impairing visibility at Carlsbad Caverns and Guadalupe Mountains National Parks. Was this addressed in the SIP revision? The Salt Creek Wilderness Area in southeast New Mexico shows monitored and modeled progress above the uniform rate of progress glidepath on several modeling scenarios conducted by EPA, TCEQ, and the Western Regional Air Partnership (WRAP). Is TCEQ taking any action to help address this issue, since TX emissions contribute to visibility impairment at this site?

5. Pages 6-9: NO_X and SO_2 emissions from area sources increased due to increased natural gas production and flaring at O&G wells. Were emissions from minor and area sources considered in determining what sources are subject to a four-factor analysis? Will TCEQ post four-factor analyses on its website for review?

6. Pages 7-4 and 7-5, Figures 7-1, 2: What major O&G sources are located within the AOI for White Mountain Wilderness Area (WHIT), Bosque del Apache Wilderness Area (BOAP), SACR and GUMO Class I Areas? What were the Q/d values for those sources? NMED would like to review the Q/d analyses for these Class I areas.

7. Pages 7-12: Units with NO_X or SO_2 <5% of the total emissions of the same pollutant were removed from further control measure analysis screening, based on consideration of the cost to control and anticipated improvement in visibility. If a source had a Q/d >5, then TCEQ should complete the 4-factor analysis for these sources. NMED requests additional justification for selecting 15 years as the remaining useful life of control equipment. A justification for this assumption would help explain why the selected remaining useful like is practical.

8. Page 7-13: The upper end of the cost threshold, $10,000/ton, was determined to be inappropriate to apply to existing sources not undergoing any kind of physical or operational change. To how many of the screened sources would this apply?

9. Appendix A: TCEQ used a 10% interest rate in their cost calculations instead of the bank prime rate for both EGUs and non-EGUs as a conservative assumption. An appropriate interest rate (current bank prime) should be used instead of an assumed rate without any basis. It could make a difference on whether additional controls are cost effective at a particular facility.

10. What factors did TCEQ consider for selecting sources on a per pollutant basis, rather than combined emissions of SO_2 and NO_X? The question of analyzing the pollutants separately was previously raised with TCEQ. Sources were screened for Q/d individually using NO_X or SO_2. Is TCEQ aware of other states that are conducting their Q/d analyses in this manner? NPS comments suggest that there are facilities that would be required to undergo four-factor analysis if the cumulative Q/d was considered. The Q/d screening criteria used to evaluate the

impact of new facilities on Class I Areas considers cumulative emissions from all criteria pollutants (2010 FLAG guidance, page 18, Initial Screening Criteria).

11. A capital recovery factor (CRF) of fifteen (15) years was used to estimate annualized capital costs for each potential control measure. New Mexico facilities' CRFs were generally 20-25 years. Did TCEQ use 15 years across the board? Based on NMED's review of different control technology, this capital recovery factor may not be appropriate.

12. WRAP has recently posted updated Weighted Emissions Potential (WEP) and AOI modeling results for Class I areas (CIAs) on the Technical Support Site (TSS): http://views.cira.colostate.edu/tssv2/. A number of CIAs in New Mexico show that facilities from Texas are within the top 20 of the facility-level rank point results for NOx and SO_2. Several of these, having a Q/d (where Q is on an individual pollutant basis) of greater than 5, have not been analyzed by TCEQ in their Four Factor Analysis. If a cumulative NOx and SO_2 basis for Q is used, even more sources are unaccounted for in the analysis. These facilities should undergo further four factor analysis review and consideration of additional controls to reduce impacts at Class I areas in NM. Rank point results show the top facilities ranked by weighted emissions potentials whose emissions have the potential to contribute to visibility impairment due to their emissions on the Most Impaired Days (MID) for each year in 2014-2018. More information on the rank point results is available on the TSS, as well as results for the CIAs in each state, including NM and TX.

NMED and the City of Albuquerque/Bernalillo County are currently working together on the development of our respective Regional Haze State Implementation Plan revisions. NMED has a dedicated website to the development of the 2021 Regional Haze SIP at https://www.env.nm.gov/air-quality/reg-haze/. We would like to continue the consultation process with you and our EPA Regional Office as more of this information is completed and delivered to the WRAP TSS Site at https://views.cira.colostate.edu/tssv2/. The WRAP TSS site will provide modeling and analysis information for Western States and is being used to help WRAP states develop their 2021 SIPs. Both NMED, City of Albuquerque/Bernalillo County and TCEQ should work cooperatively to try to help ensure that the Federal Land Managers concerns are addressed. This will help ensure that both states fulfill their responsibilities to take prudent actions so that the views at our CIAs will continue to improve. This will also help set the stage for better cooperation on other state initiatives aimed at improving air quality in the areas near our border.

We look forward to meeting with you again soon to discuss these issues and next steps. Should you have questions or require clarification, please contact Mark Jones, mark.jones@state.nm.us, or Kerwin Singleton, kerwin.singleton@state.nm.us.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau
Environmental Protection Division
New Mexico Environment Department

NEW MEXICO
ENVIRONMENT DEPARTMENT

Michelle Lujan Grisham
Governor

Howie C. Morales
Lt. Governor

525 Camino de los Marquez, Suite 1
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James C. Kenney
Cabinet Secretary

Jennifer J. Pruett
Deputy Secretary

February 2, 2021

Ms. Tonya Baer
Director, Air Quality Division
Texas Commission on Environmental Quality (TCEQ)
P.O. Box 13087
Austin, TX 78711-3087
tonya.baer@tceq.texas.gov

Re: Additional Comments on TCEQ's Proposed 2021 Regional Haze State Implementation Plan (SIP) Revision for the Second Planning Period (Project No. 2019-112-SIP-NR)

Dear Director Baer,

The New Mexico Environment Department (NMED) reviewed the Texas Commission on Environmental Quality's (TCEQ) Proposed 2021 Regional Haze SIP Revision (Project No. 2019-112-SIP-NR) and submitted formal comments on January 8, 2021. As a follow-up to our submittal, Walker Williamson of the TCEQ Regional Haze Team contacted NMED on January 11, 2021 concerning comments #4 and #12, and requested clarification and specific requests concerning facilities for which NMED would like TCEQ to conduct further analysis. This follow up letter clarifies those requests and supplements the comments we submitted on January 8, 2021.

The Weighted Emissions Potential (WEP) and Area of Influence (AOI) modeling results for Class I Areas (CIAs), available on the Western Regional Air Partnership (WRAP) Technical Support Site (TSS): http://views.cira.colostate.edu/tssv2/, identify a number of Texas facilities that are within the top 20 of the facility-level rank point results for NO_X and SO_2. These facilities are reasonably anticipated to affect visibility conditions at several CIAs in New Mexico. NMED asks that TCEQ evaluate the facilities listed in the attached, *Appendix A: Texas Facilities with Reasonable Potential to Impact Visibility Impairment at New Mexico Class I Areas*, for potential additional controls and visibility impacts. Furthermore, NMED asks that TCEQ evaluate for potential additional controls any additional facilities identified by the U.S. National Park Service (NPS) contained in Appendix A of TCEQ's Proposed 2021 Regional Haze SIP Revision.

We look forward to meeting with TCEQ to discuss our original and supplemental comments as part of the ongoing consultation process. Should you have questions or require clarification, please contact Mark Jones, mark.jones@state.nm.us, or Kerwin Singleton, kerwin.singleton@state.nm.us.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau
New Mexico Environment Department

Re: New Mexico Environment Department (NMED) Additional Specific "Asks" on TCEQ's Proposed 2021 Regional Haze State Implementation Plan Revision for the Second Planning Period (Project No. 2019-112-SIP-NR)
Appendix A: Texas Facilities with Reasonable Potential to impact Visibility impairment at New Mexico Class I Areas

FacilityID	FacilityName	BAND		BOAP		GICL		SACR		SAPE		WHIT		WHPE		GUMO (for CAVE)	
		NOx Rank	SO2 Rank	NOx Rank	SO2 Rank	NOx Rank	SO2 Rank	NOx Rank	SO2 Rank	NOx Rank	SO2 Rank	NOx Rank	SO2 Rank	NOx Rank	SO2 Rank	NOx Rank	SO2 Rank
5649411	BIG SPRING CARBON BLACK PLANT	133	5	513	10	266	266	197	8	360	8	320	10	537	13	151	2
4163111	BLOCK 31 GAS PLANT	99	363	149	323	55	55	31	220	135	416	27	235	54	422	15	224
4863711	BORGER CARBON BLACK PLT	62	9	155	11	104	104	227	21	101	9	152	16	58	5	338	38
5617211	CALAVERAS PLANT	429	116	530	76	530	530	303	122	1034	215	166	48	120	80	115	16
5765911	COYANOSA GAS PLANT	603	25	402	13	259	259	263	13	686	32	157	9	662	31	125	1
6534211	EG HILL COMPRESSOR	9	913	85	1512	68	68	207	1410	25	1183	122	1116	6	942	260	1620
4898411	FULLERTON GAS PLANT	220	31	27	18	28	28	53	17	148	43	30	17	68	33	8	13
6507511	GOLDSMITH GAS PLANT	85	20	167	17	87	87	33	11	226	36	84	12	115	28	66	8
6497411	GOMEZ GAS PLANT	1164	131	716	50	614	614	522	78	1221	116	440	44	1442	141	275	19
6388711	GUADALUPE COMPRESSOR STATION	835	2074	343	1288	283	283	492	1478	972	2408	335	962	1103	2709	1	239
5745311	HARRINGTON STATION POWER PLANT	16	4	11	4	14	14	28	6	14	2	4	3	17	3	93	6
4035711	KEYSTONE GAS PLANT	70	63	102	58	72	72	20	42	132	73	25	45	123	103	34	32
4025911	MI VIDA GAS PLANT	899	71	416	30	366	366	312	56	653	59	269	27	750	79	101	11
6671211	PAMPA PLANT	107	30	52	26	105	105	157	46	34	10	118	57	73	21	278	51
4205911	RAMSEY GAS PROCESSING PLANT	439	155	197	79	212	212	288	111	632	174	201	70	692	184	39	18
16868511	RED BLUFF GAS PROCESSING PLANT	254	509	105	333	94	94	213	306	408	554	101	274	375	616	11	171
2904911	SHERHAN GAS PLANT	19	47	221	153	196	196	308	178	62	67	257	152	30	37	377	242
4930011	TOLK STATION	29	2	8	2	20	20	25	2	21	3	5	1	14	1	90	3
3968411	WA PARISH ELECTRIC GENERATING STATION	21771	12248	2861	120	13694	13694	1261	99	19282	13883	17082	6328	18741	12537	315	10
6476111	WESTERN REFINING EL PASO	263	110	19	38	26	26	269	121	380	147	26	38	464	173	106	35

From:	Jones, Mark, ENV
To:	walker.williamson@tceq.texas.gov; margaret.earnest@tceq.texas.gov
Cc:	Miller, Kenneth, ENV; Sanchez, Alex, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV; Vigil, Christopher J, ENV
Subject:	NMED Draft Regional Haze SIPr [External Review Draft - Version 2024-05-20]
Date:	Thursday, June 20, 2024 8:55:00 AM
Attachments:	2024-05-20_NMED Draft Regional Haze SIPr Narrative [External Review Draft].pdf

Dear Regional Haze Representatives from Texas Commission on Environmental Quality,

The New Mexico Environment Department (NMED) Regional Haze planning team has completed a draft Regional Haze SIP revision for the second planning period (2019-2028) [Version 2024-05-20, attached]. The plan is intended to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. Please note that this draft is not for public distribution, as we are currently in the middle of the formal FLM consultation period and are only sharing it with governmental entities at this time.

We are providing it to you today, June 20, 2024, to further facilitate communication with states during this pre-hearing coordination and consultation phase. We request that you provide any comments on this draft by July 19, 2024.

If you have any questions you may contact me at the phone number or email address provided below.

Best Regards,
Mark

Mark Jones | Environmental Analyst
Regional Haze Team - Technical Lead
NMED Air Quality Bureau | www.env.nm.gov/air-quality/
mark.jones@env.nm.gov | (505) 629-6626

Science | Innovation | Collaboration | Compliance

From:	Jones, Mark, ENV
To:	ponikvar.alex@azdeq.gov; li.yi@azdeq.gov
Cc:	Miller, Kenneth, ENV; Sanchez, Alex, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV; Vigil, Christopher J, ENV
Subject:	NMED Draft Regional Haze SIPr [External Review Draft - Version 2024-05-20]
Date:	Thursday, June 20, 2024 8:51:00 AM
Attachments:	2024-05-20_NMED Draft Regional Haze SIPr Narrative [External Review Draft].pdf

Dear Regional Haze Representatives from Arizona Department of Environmental Quality,

The NMED Regional Haze planning team has completed a draft Regional Haze SIP revision for the second planning period (2019-2028) [Version 2024-05-20, attached]. The plan is intended to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. Please note that this draft is not for public distribution, as we are currently in the middle of the formal FLM consultation period and are only sharing it with governmental entities at this time.

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If you have any questions you may contact me at the phone number or email address provided below.

Best Regards,
Mark

Mark Jones | Environmental Analyst
Regional Haze Team - Technical Lead
NMED Air Quality Bureau | www.env.nm.gov/air-quality/
mark.jones@env.nm.gov | (505) 629-6626

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From:	Jones, Mark, ENV
To:	Chelsea Cancino; Glade Sowards
Cc:	Miller, Kenneth, ENV; Sanchez, Alex, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV; Vigil, Christopher J, ENV
Subject:	NMED Draft Regional Haze SIPr [External Review Draft - Version 2024-05-20]
Date:	Thursday, June 20, 2024 8:56:00 AM
Attachments:	2024-05-20_NMED Draft Regional Haze SIPr Narrative [External Review Draft].pdf

Dear Regional Haze Representatives from Utah Department of Environmetal Quality,

The New Mexico Environment Department (NMED) Regional Haze planning team has completed a draft Regional Haze SIP revision for the second planning period (2019-2028) [Version 2024-05-20, attached]. The plan is intended to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. Please note that this draft is not for public distribution, as we are currently in the middle of the formal FLM consultation period and are only sharing it with governmental entities at this time.

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If you have any questions you may contact me at the phone number or email address provided below.

Best Regards,
Mark

Mark Jones | Environmental Analyst
Regional Haze Team - Technical Lead
NMED Air Quality Bureau | www.env.nm.gov/air-quality/
mark.jones@env.nm.gov | (505) 629-6626

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From:	Jones, Mark, ENV
To:	joshua.korth@state.co.us; weston.carloss@state.co.us; richard.coffin@state.co.us
Cc:	Miller, Kenneth, ENV; Sanchez, Alex, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV; Vigil, Christopher J, ENV
Subject:	NMED Draft Regional Haze SIPr [External Review Draft - Version 2024-05-20]
Date:	Thursday, June 20, 2024 8:53:00 AM
Attachments:	2024-05-20_NMED Draft Regional Haze SIPr Narrative [External Review Draft].pdf

Dear Regional Haze Representatives from Colorado Department of Public Health and Environment,

The New Mexico Environment Department (NMED) Regional Haze planning team has completed a draft Regional Haze SIP revision for the second planning period (2019-2028) [Version 2024-05-20, attached]. The plan is intended to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. Please note that this draft is not for public distribution, as we are currently in the middle of the formal FLM consultation period and are only sharing it with governmental entities at this time.

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If you have any questions you may contact me at the phone number or email address provided below.

Best Regards,
Mark

Mark Jones | Environmental Analyst
Regional Haze Team - Technical Lead
NMED Air Quality Bureau | www.env.nm.gov/air-quality/
mark.jones@env.nm.gov | (505) 629-6626

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From:	Jones, Mark, ENV
To:	melanie.foster@deq.ok.gov
Cc:	Miller, Kenneth, ENV; Sanchez, Alex, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV; Vigil, Christopher J, ENV
Subject:	NMED Draft Regional Haze SIPr [External Review Draft - Version 2024-05-20]
Date:	Thursday, June 20, 2024 8:58:00 AM
Attachments:	2024-05-20_NMED Draft Regional Haze SIPr Narrative [External Review Draft].pdf

Dear Regional Haze Representatives from Oklahoma Department of Environmental Quality,

The New Mexico Environment Department (NMED) Regional Haze planning team has completed a draft Regional Haze SIP revision for the second planning period (2019-2028) [Version 2024-05-20, attached]. The plan is intended to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. Please note that this draft is not for public distribution, as we are currently in the middle of the formal FLM consultation period and are only sharing it with governmental entities at this time.

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If you have any questions you may contact me at the phone number or email address provided below.

Best Regards,
Mark

Mark Jones | Environmental Analyst
Regional Haze Team - Technical Lead
NMED Air Quality Bureau | www.env.nm.gov/air-quality/
mark.jones@env.nm.gov | (505) 629-6626

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From:	Jones, Mark, ENV
To:	Smith, Morgan A.; Lehner, Catalina
Cc:	Miller, Kenneth, ENV; Sanchez, Alex, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV; Vigil, Christopher J, ENV
Subject:	NMED Draft Regional Haze SIPr [External Review Draft - Version 2024-05-20]
Date:	Thursday, June 20, 2024 9:03:00 AM
Attachments:	2024-05-20_NMED Draft Regional Haze SIPr Narrative [External Review Draft].pdf

Dear Regional Haze Representatives from City of Albuquerque Environmental Health Department,

The NMED Regional Haze planning team has completed a draft Regional Haze SIP revision for the second planning period (2019-2028) [Version 2024-05-20, attached]. The plan is intended to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. Please note that this draft is not for public distribution, as we are currently in the middle of the formal FLM consultation period and are only sharing it with governmental entities at this time.

We are providing it to you today, June 20, 2024, to further facilitate communication with states during this pre-hearing coordination and consultation phase. We request that you provide any comments on this draft by July 19, 2024.

If you have any questions you may contact me at the phone number or email address provided below.

Best Regards,
Mark

Mark Jones | Environmental Analyst
Regional Haze Team - Technical Lead
NMED Air Quality Bureau | www.env.nm.gov/air-quality/
mark.jones@env.nm.gov | (505) 629-6626

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From:	Alex Ponikvar
To:	Jones, Mark, ENV
Cc:	li.yi@azdeq.gov; Miller, Kenneth, ENV; Sanchez, Alex, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV; Vigil, Christopher J, ENV
Subject:	[EXTERNAL] Re: NMED Draft Regional Haze SIPr [External Review Draft - Version 2024-05-20]
Date:	Thursday, July 18, 2024 5:53:11 PM

CAUTION: This email originated outside of our organization. Exercise caution prior to clicking on links or opening attachments.

Hi Mark,

Thank you for the opportunity to review NMED's draft regional haze SIP revision. We have no comments on the plan or requests at this time, so I'm providing the affirmations below based on the template language from our own regional haze interstate consultation.

Please let me know if you have any questions and thank you again.

At this time, ADEQ confirms the following statements regarding our interstate consultation with New Mexico Environment Department ("NMED") for the regional haze second implementation period:

1. Pursuant to 40 CFR 51.308(f)(2)(ii)(A), ADEQ and NMED have not agreed on any measures during our state-to-state consultation.
2. Pursuant to 40 CFR 51.308(f)(2)(ii)(B), the following statements are true:
   a. ADEQ has shared the measures they have identified, to date, as being necessary to make reasonable progress in a mandatory Class I Federal area with NMED.
   b. ADEQ has not requested for NMED to consider any measures to achieve its apportionment of emission reduction obligations in a mandatory Class I Federal area.
3. Pursuant to 40 CFR 51.308(f)(2)(ii)(C), there are currently no disagreements between ADEQ and NMED on the emission reduction measures necessary to make reasonable progress in a mandatory Class I Federal area.

Thank you,

Alex Ponikvar
Environmental Legal Specialist III
602-771-4601

azdeq.gov

On Thu, Jun 20, 2024 at 7:52 AM Jones, Mark, ENV <Mark.Jones@env.nm.gov> wrote:

> Dear Regional Haze Representatives from Arizona Department of Environmental Quality,

The NMED Regional Haze planning team has completed a draft Regional Haze SIP revision for the second planning period (2019-2028) [Version 2024-05-20, attached]. The plan is intended to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. Please note that this draft is not for public distribution, as we are currently in the middle of the formal FLM consultation period and are only sharing it with governmental entities at this time.

We are providing it to you today, June 20, 2024, to further facilitate communication with states during this pre-hearing coordination and consultation phase. We request that you provide any comments on this draft by July 19, 2024.

If you have any questions you may contact me at the phone number or email address provided below.

Best Regards,

Mark

Mark Jones | Environmental Analyst

Regional Haze Team - Technical Lead

NMED Air Quality Bureau | www.env.nm.gov/air-quality/

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Science | Innovation | Collaboration | Compliance

July 16, 2024

Mark Jones
New Mexico Environment Department
Air Quality Bureau
1190 St. Francis Drive, Suite N4050
Santa Fe, New Mexico 87505

VIA EMAIL

Subject: Pre-hearing Review of NMED Draft Regional Haze SIPr Narrative (v 2024-05-20)

Dear Mark Jones:

Thank you for providing an external review draft of New Mexico Environment Department's (NMED) Regional Haze (RH) State Implementation Plan (SIP) revision for the second planning period. Texas Commission on Environmental Quality Air Quality Division staff reviewed NMED's draft and offer the following feedback concerning emissions assessment elements in the draft SIP revision.

The emissions inventory (EI) for NMED's draft SIP revision relies on a 2014 base year and a 2016 projection base year. While certain portions of Western Regional Air Partnership (WRAP) states' EIs have been updated with more recent data, the U.S. Environmental Protection Agency's (EPA) 2014v2 and 2016v1 modeling platforms for Texas contain older emissions data. As a result, the NMED RH Plan overestimates Texas' 2028 projected emissions.

NMED's draft SIP revision is predicting slightly over one million tons of 2028 nitrogen oxides (NO_X) emissions in Texas while the most recent 2020 Texas EI indicates 800,000 tons of NO_X emissions statewide, with on-road mobile comprising the majority (55%) of those emissions. Predicting a statewide NO_X emissions increase of 25% over an eight-year period is unrealistic. Mobile source emissions have declined over the past years and are anticipated to continue to decline due to existing EPA engine standards, recent EPA rulemaking, and continued fleet turnover.

The Texas on-road mobile EIs in NMED's draft SIP revision appear to be developed using EPA's Motor Vehicle Emissions Simulator (MOVES) version 2014 (MOVES2014), instead of the more recent MOVES3 or MOVES4 models. The newer versions of MOVES incorporate the most recent national emission standards, vehicle populations and activity, and fuels data. The non-point EI data in the 2014v2 and 2016v1 modeling platforms rely heavily on EPA's 2011 and/or 2014 national emissions inventory (NEI).

For the majority of Texas' non-point sectors (area source, all non-road mobile sources except airport sources, and on-road mobile sources), TCEQ notes that the EPA modeling platform 2016v3 would be more appropriate for the following reasons:

- 2016v3 has 2017 NEI updates;
- 2016v3 uses MOVES3 to estimate on-road mobile source emissions while 2016v1 uses the older MOVES2014; and
- 2016v3 includes Texas' updated oil and gas emissions.

TCEQ notes that both the 2016v1 (currently used for NMED's draft SIP revision) and the 2016v3 modeling platforms contain significant errors for Texas point source and airport sector emissions. For further reference, TCEQ submitted comments on EPA's proposed Federal Implementation Plan (FIP) Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard (NAAQS) regarding these errors.[1] TCEQ's 2022 point source data submitted to EPA and, for the airport sector, TCEQ's 2020 NEI submission are more representative of Texas' emissions.

We appreciate NMED providing for early review during development of its regional haze SIP revision. Please contact Jamie Zech (jamie.zech@tceq.texas.gov) of my staff with questions concerning TCEQ's comments or to coordinate additional regional haze consultation.

Sincerely,

Donna F. Huff, Deputy Director
Air Quality Division

[1] https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0505

E.2 Informal Discussions with Federal Land Managers

Supporting documentation for NMED coordination with Federal Land Managers (FLMs) is provided below. The following documents are included in this section (in reading order):

- FLM Communications
    - USNPS email on Source Selection (7/25/19)
    - USNPS email on Xcel Cunningham Station (9/4/20)
    - USNPS follow-up email Xcel Cunningham Station (7/6/21)
    - USFS letter (1/27/22)
    - USFS informal comments (7/19/24)
    - NMED Notification to FLMs on Upcoming Public review Draft SIPr and Companion Rule (8/19/24)

From: Shepherd, Don
To: Jones, Mark, ENV
Cc: Pat Brewer; Kirsten King; Bret Anderson; Paige, Carrie; Ed Merta; Feldman, Michael; Grady.James@epa.gov; Johnson, Owen, NMENV; Triepke, Jack -FS; Born, Kenneth - FS; Medina.Dayana@epa.gov; Kuehn, Elizabeth, ENV; Singleton,Kerwin, NMENV; Baca, Michael, ENV; Debra Miller; Andrea Stacy; Rocha, Dario W.; tmoore@westar.org
Subject: [EXT] Re: [EXTERNAL] RE: NM Regional Haze Source Selection for Four-Factor Analysis
Date: Thursday, July 25, 2019 3:04:57 PM

Mark,

Thanks so much for your consideration of our comments and your response. This sets a model for how states and FLM can work together as we enter this second round of regional haze efforts. Please be assured that we shall do everything we can to assist you in this effort, and please do not hesitate to contact us whenever appropriate.

On Thu, Jul 25, 2019 at 10:33 AM Jones, Mark, NMENV <Mark.Jones@state.nm.us> wrote:

> Greetings,
>
> The New Mexico Environment Department Air Quality Bureau (NMED AQB) has decided to approve the selection of a screening threshold that accounts for 80% of the emissions from major sources in NM. The 24 prioritized sources (including one source within the jurisdiction of Albuquerque/Bernalillo County), have been contacted to explain the Regional Haze Rule and the four-factor analysis process. CABQ EHD contacted the source within their jurisdiction. Furthermore, because the Blanco C&D Compressor Station is jointly permitted with the Harvest Pipeline – San Juan Gas Plant and the El Paso Natural Gas Company – Blanco Compressor Station A, NMED is requesting a combined four-factor analysis for these three facilities.
>
> We also have a new NMED AQB regional haze planning website for the 2nd 10-year planning period at https://www.env.nm.gov/air-quality/reg-haze/.
>
> Thank you,
>
> Mark Jones
>
> Environmental Analyst
>
> New Mexico Environment Department
>
> Air Quality Bureau
>
> 1800 E. 30th St. Suite B
> Farmington, NM 87401
>
> Office: (505) 566-9746
>
> Mark.Jones@state.nm.us
>
> https://www.env.nm.gov/
>
> "Innovation, Science, Collaboration, Compliance"

From: Shepherd, Don <don_shepherd@nps.gov>
Sent: Tuesday, June 18, 2019 3:53 PM
To: Jones, Mark, NMENV <Mark.Jones@state.nm.us>
Subject: [EXT] Re: [EXTERNAL] RE: NM Regional Haze Source Selection for 4-Factor Analysis

Hi Mark,

Thanks for the revised lists of potential facilities for RP analyses.

We appreciate your efforts and can support your "List of 26 Facilities Q/d>5 81.5% Title V emissions" and your "List of 24 Facilities Q/d>5.7 80.1%" with one modification. It is our understanding that Blanco Compressor Station A has been treated as part of a facility that includes the San Juan Gas Plant and the Blanco Compressor C & D Station for NSR purposes. (Please see the attached permit.) Because both the San Juan Gas Plant and the Blanco Compressor C & D Station are on your lists (as well as ours--along with Blanco Compressor Station A), it seems appropriate to continue to evaluate these three sources together.

Would NMED conduct the RP analysis for the GCC Rio Grand Portland Cement Plant even though it is in Bernallio County?

Please feel free to contact me with any questions and comments.

==========

This message has been analyzed by Deep Discovery Email Inspector.

--
Don Shepherd
National Park Service
Air Resources Division
12795 W. Alameda Pkwy.
Lakewood, CO 80228
Phone: 303-969-2075
Fax: 303-969-2822
E-Mail: don_shepherd@nps.gov
"the man who really counts in the world is the doer, not the mere critic" TR 1891

NPS feedback on Xcel Cunningham Station boilers 4-factor analysis

Shepherd, Don <Don_Shepherd@nps.gov>

Fri 9/4/2020 8:25 PM

To: Mark Jones <mark.jones@state.nm.us>; Singleton,Kerwin, NMENV <Kerwin.Singleton@state.nm.us>

2 attachments (221 KB)

Xcel Cunningham 122B.xlsm; Xcel Cunningham 121B.xlsm;

Hi Mark & Kerwin,

As requested, i am providing some initial feedback on Xcel 's Cunningham Station boilers 4-factor analysis. I applied EPA's Control Cost Manual (CCM) workbook with inputs from CAMD/AMP. I used the current prime interest rate (3.25%) as recommended by the CCM, along with the CCM estimate of 30-year SCR life. Assuming that SCR could achieve 78% - 80% control efficiency, the CCM method yields cost-effectiveness of $5055/ton to remove 175 tpy from Boiler 121B and 5438/ton to remove 328 tpy from Boiler 122B. These costs were escalated to 2019$ by application of the CEPCI and are very reasonable compared to thresholds used in Round #1 (up to $7300/ton).

Please let me know if you hav e any questions.

From:	Shepherd, Don
To:	Jones, Mark, ENV; Singleton,Kerwin, NMENV
Cc:	Peters, Melanie; Stacy, Andrea; King, Kirsten L; Miller, Debra C; Devore, Lisa M
Subject:	more feedback on Cunningham
Date:	Tuesday, July 6, 2021 2:02:28 PM
Attachments:	2021.6.21 4F TSD Cunningham.pdf Copy of Xcel Cunningham 121B.xlsm Copy of Xcel Cunningham 122B.xlsm Cunningham GS 4FA by NMED.xlsx NG boilers w SCR less than 03 lb per mmBtu.xlsx NPS feedback on Xcel Cunningham Station boilers 4-factor analysis.pdf

---

Hi Mark & Kerwin,

As you requested, i am providing additional feedback (sine our 9/2020 feedback--attached) on Xcel's Cunningham Generating Station.

I think the main issues are the ability of modern SCR to achieve very low NOx emissions rates on natural gas-fired boilers and the interest rates applicable to certain public utilities.

I suggest that there are two fundamental constraints on modern SCR systems; an upper bound on efficiency, and a lower bound on emission rate (in lb/mmbtu). It is generally accepted that modern SCR can achieve at least 90% NOx control, but efficiency is ultimately limited by the concentration of NOx in the gas stream to be treated.

In the TSD for Cunningham, NMED assumed 80% NOx control, which would result in a NOx emission rate of about 0.03 lb/mmBtu.

I searched 2020 (CAMD) data and found hundreds of examples of gas-fired emission units with SCR achieving lower NOx emission rates. I refined my search to just NG-fired boilers (like the two Cunningham boilers) and still found the 13 shown in the attached spreadsheet.

If we assume that SCR can achieve 90% control on those two Cunningham boilers, we get an emission rate of about 0.02 lb/mmBtu, and we see that there are at least six boilers (in CA) that could meet this limit. I concluded that 90% NOx control by SCR is achievable at Cunningham, so i entered 0.02 lb/mmBtu into the Control Cost Manual (CCM) workbooks. (attached)

I am also beginning to realize that some utilities borrow money at rates higher than the prime, so i entered the Xcel rate (7.19%) into the CCM workbook.

I linked my CCM results to the table NMED produced for Cunningham boilers to provide a direct comparison between the two sets of estimates. I estimate that almost 600 ton/yr of NOx could be reduced by adding SCR to both Cunningham boilers at cost-effectiveness values < $7000/ton.

I hope this helps. Please feel free to contact me if you have any questions.

USDA **United States Department of Agriculture** **Forest Service** **Southwestern Region Regional Office**

333 Broadway SE
Albuquerque, NM 87102
505-842-3292
Fax: 505-842-3800

File Code: 5180
Date: January 27, 2022

Michael Baca
Control Strategies Manager
NMED Air Quality Bureau
1800 E. 30th St. Suite B
Farmington, NM 87401
michael.baca1@state.nm.us
Tel (505) 629-6626

Dear Michael:

USDA's Forest Service recently published a 10-year strategy to reduce wildfire - *Confronting the Wildfire Crisis: A Strategy for Protecting Communities and Improving Resilience in America's Forests* (https://www.fs.usda.gov/sites/default/files/Confronting-Wildfire-Crisis.pdf). Prescribed fire is one of the best tools to increase the pace and scale of wildfire risk mitigation work. Regionally we have been increasing the use of prescribed fire well above the Western Regional Air Partnership's (WRAP) baseline emission inventory, which is based on activity levels present from 2014. In addition, we anticipate that prescribed fire will increase by 20 million acres on Forest Service land in the West and by 30 million acres on other ownerships over the next 10 years.

Prescribed fire smoke is considered man-made air pollution under the Regional Haze Rule. The Regional Haze process allows the State of New Mexico to adopt an adjustment for prescribed fire into their Regional Haze State Implementation Plan. We believe doing so is the best way to fully utilize the provisions of the Regional Haze Rule and disclose the reality of additional prescribed fire smoke as we work to improve the ecological condition of our national forests and address the growing wildfire risk within the State. The prescribed fire adjustment as represented in the WRAP's Future Fire Scenario 2 represents a critical commitment by the State of New Mexico in our shared forest management objectives. If you have questions, please reach out to Anita Rose (anita.rose@usda.gov) or Bret Anderson (bret.a.anderson@usda.gov). Thank you for your consideration of this important issue.

Sincerely,

ELAINE KOHRMAN
Digitally signed by ELAINE KOHRMAN
Date: 2022.01.27 13:35:22 -07'00'

MICHIKO J. MARTIN
Regional Forester

Enclosure

cc: Anita Rose, anita.rose@usda.gov & Bret Anderson, bret.a.anderson@usda.gov

Prescribed Fire Talking Points for New Mexico

- The USDA FS takes our affirmative responsibility to protect Class I Areas seriously as mandated in the Clean Air Act.
- The Regional Haze process allows the State of New Mexico to adopt an adjustment for prescribed fire. We believe doing so is the best way to disclose the reality of additional prescribed fire smoke as we work to improve the ecological condition of our National Forests and address the growing wildfire risk within the State.
- We recognize that the prescribed fire adjustment produces only a small change in the visibility assessments; however, it represents a critical commitment by the State of New Mexico in our shared Forest Management objectives.
- We continue to see longer and more severe wildfire seasons and recognize the need for a significant investment and treatment of our landscapes to mitigate the catastrophic effects of unwanted wildfire.
- Prescribed fire is one of the best tools to increase the pace and scale of wildfire risk mitigation work.
- Fire plays an important role in shaping the vegetation and landscape in New Mexico and surrounding states. Recurring fire has been a part of the landscape for thousands of years.
- Aggressive fire suppression, coupled with an array of other disturbances has changed the historic composition and structure of the Forests. Periodic prescribed burning and other vegetation management can recreate the ecological role of fire in a controlled manner.
- Fire and fuels management supports a variety of desired conditions and objectives across the Forests and Grasslands (e.g., community protection, hazardous fuels reduction, native ecosystems restoration, historic fire regimes restoration, wildlife openings, and open woodland creation, etc.).
- The USDA FS along with our partners in the New Mexico Energy Minerals and Natural Resources Department (EMNRD) Forestry Division plan to significantly increase the use of prescribed fire to accomplish these goals.
- The Federal Infrastructure Bill directs Agency priorities and supports prescribed fire use as a tool for increasing the pace and scale of risk mitigation projects. The upward trend of prescribed fire implementation will continue growing significantly in the coming years.
- Acknowledging increased prescribed fire activity and its effect on visibility through the adoption of the end-point adjustment demonstrates the support of prescribed fire projects designed to protect landscapes and people in New Mexico.
- The USDA FS is not alone in requesting the end-point adjustment. State and Federal land management agencies stand together to recognize the critical role prescribed fire plays in risk mitigation work and plan to capitalize on funding and increase the application of prescribed fire across the State.
- We request the State adopt the increased prescribed fire end-point adjustment, and we stand ready to assist with any data needs or coordination.

New Mexico Draft Revised RH SIP – USDA FS Southwestern Region Comments

Chapter 1

Chapter 2

- Descriptions of Pecos (p. 26) and San Pedro Parks (p. 30) Wilderness Areas include comments about grazing that are irrelevant to this SIP and we respectfully request that they be removed. Protection of certain grazing rights in Wilderness Areas are established by Congress: Section 4(d)(4)(2) of the Wilderness Act states: "the grazing of livestock where established prior to the effective date of this Act, shall be permitted to continue subject to such reasonable regulations as subject to such reasonable regulations as are deemed necessary by the Secretary of Agriculture".

Chapter 3

- (p. 37) link at footnote 56 is broken: https://views.cira.colostate.edu/tssv2/Lists/Glossary.aspx
- (p. 41) consider adding a footnote w/link at the end of the paragraph that concludes with the sentence "Full versions of the bar graphs in this map, and other detailed visualizations of monitor trends, are available on the WRAP TSS."
- (p. 51 and p. 54) Figures 3-6 and 3-8 show NC 2064 on clearest days as negative numbers for WHPE1 and SAPE1 – consider providing clarification as to why that is.

Chapter 4

Chapter 5

Chapter 6

Section 6.4 – Tier Two – PTE

"NMED determined that a four-factor analysis would only be required on individual equipment with a PTE greater than ten pounds per hour of NO_x or SO_2 pursuant"

- No change needed, just curious if NMED anticipates analyzing these smaller sources in the future?

Chapter 7

Chapter 8

- Figure 8-8 – the word Wheeler needs to be added to the figure title,

Chapter 9

Chapter 10

Chapter 11

Chapter 12

“EPA sends the funds to the National Park Service (NPS) via an interagency agreement for them to operate the network”

- While it is true that NPS is the central contracting agency for IMPROVE, which gives them de facto operational control of all aspects of the portion funded by EPA (though NPS heavily weighs the opinions of the Steering Committee), this statement seems a bit misleading since the sites themselves are operated with personnel from all the other participating agencies, including the Forest Service, and the infrastructure is maintained without funding from NPS/EPA. Please considering clarifying.

Appendix A

Appendix B

Appendix C

From:	Jones, Mark, ENV
To:	Rose, Anita -FS; Kerry Jones
Cc:	Miller, Kenneth, ENV; Sanchez, Alex, ENV; Butt, Neal, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV
Bcc:	Jones, Mark, ENV
Subject:	Notification of Upcoming Availability of Public Review Drafts of Regional Haze SIP Revision and Companion Rule 20.2.68 NMAC
Date:	Monday, August 19, 2024 3:16:40 PM

Dear representatives from the U.S. Forest Service,

NMED's Regional Haze planning team is working to complete its draft Regional Haze state implementation plan (SIP) revision for the second planning period (2019-2028) in anticipation of petitioning the New Mexico Environmental Improvement Board (EIB) to hold a hearing on the plan in late fall or early winter. The NMED team is currently finishing substantive revisions to the draft SIP based on the feedback we received from the FLMs during the 60-day consultation period. NMED then plans to release public review drafts of the revised SIP and a new companion rule, 20.2.68 NMAC – Regional Haze Requirements, for review and comment by the members of the public, industry, and other stakeholders before finalizing the plan and rule and formally proposing them to the EIB. The purpose of the new companion rule is to establish enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress during the second planning period, and provisions to make these measures practically enforceable.

The NMED team anticipates sharing the public review drafts via our website, https://www.env.nm.gov/air-quality/reg-haze/, on or about **August 26, 2024**. As key partners in the Regional Haze program, we are giving you advance notice of the upcoming review period and the opportunity to submit additional feedback or comments on the revised SIP and new companion rule to us by the end of the day on **September 20, 2024**. We note that you can also submit comments on the proposed plan and rule during the formal 30-day public comment period that precedes the hearing. Although the exact dates are not known now, we will provide updates on our Regional Haze website (https://www.env.nm.gov/air-quality/reg-haze/) as we continue this process. Once notice of the hearing has been published in the New Mexico Register, the proposed SIP and related documents will be posted to our public notices web page (https://www.env.nm.gov/public-notices/), and the formal public comment period will begin. We anticipate this will occur sometime in November, barring any unexpected delays.

NMED values continuing coordination between FLMs and other partners in the Regional Haze Program. If you have any questions or feedback for the NMED Regional Haze planning team, please contact me, Mark Jones (mark.jones@env.nm.gov) and cc Ken Miller (kenneth.miller@env.nm.gov), Alex Sanchez (alex.sanchez@env.nm.gov), and Eric Peters (eric.peters@env.nm.gov).

Sincerely,

Mark

Mark Jones | Environmental Analyst
Regional Haze Planning Team
NMED Air Quality Bureau | www.env.nm.gov/air-quality/
mark.jones@env.nm.gov | (505) 629-6626

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E.3 Discussions with EPA

Supporting documentation for New Mexico Environment Department (NMED) coordination with EPA Region 6 is provided below. The following documents are included in this section (in reading order):

- EPA comments
    - EPA Recommendations to NMED for FLM Draft SIP (7/30/24)
    - EPA Comments to NMED for Draft New Rule 20.68 NMAC (9/9/24)

EPA Recommendations to NMED for FLM Draft SIP:

Enforceable Emission Limits:

> The NM RH SIP states: *"To make the emissions limitations in this Regional Haze SIPr Rd2 (2019-2028) permanent and federally enforceable, NMED plans to incorporate them into facilities' New Source Review (NSR) permits issued under 20.2.72 NMAC. Unlike a Title V operating permit, which has a 5-year term, the term of an NSR permit is permanent unless withdrawn or cancelled by NMED. To ensure reasonable progress controls are added by their respective compliance deadlines, facilities are required to submit applications to incorporate new emissions limitations into their NSR permits no later than one year after final approval of this Regional Haze SIPr Rd2 (2019-2028) by EPA."*

- The proposed permit modifications must be included in NMED's SIP proposal for public review and comment, and include the permanently enforceable emissions limitations, as well as monitoring, recordkeeping and reporting requirements, and compliance schedules. Specific provisions of the permit must be identified for inclusion in the SIP with language clarifying that those provisions cannot be modified without going through a SIP process and approval by EPA. Alternatively, an agreed order containing the necessary emission limits, monitoring, recordkeeping and reporting requirements, and compliance schedule can be submitted for approval into the SIP. At the time of submittal, the permit modifications (or Agreed orders) must be finalized and included in the SIP submission. EPA cannot approve the SIP revision without enforceable emission limits that are then made federally enforceable at the time EPA approves the SIP revision. Compliance dates can be triggered upon EPA approval, if necessary.
- Please provide any additional documentation supporting the closure of facilities and/or specific units. For example, on p. 135-136 of the SIP Narrative NMED is relying on an administrative permit revision removing all of the units NMED had selected at the Saunders Gas Plant for an analysis of potential controls as the basis for NMED determining that reasonable progress does not require new controls on any of the units. Has this administrative permit revision happened? The date provided is May XX, 2024, so it is unclear if the revision has occurred.

Ambient Monitor Data Analysis:

- For section 3.2, which the New Mexico Environment Department (NMED) used to address the visibility calculation requirements in CFR 51.308(f)(1)(i-v), we recommend that NMED update this portion of the SIP to reflect more recent IMPROVE data that is currently available. The draft SIP only includes data up to 2018 which is at the end of the first planning period and does not include data from the second planning period. IMPROVE data beyond 2018 is readily available and should be used to reflect the second planning period. NMED defined an interim period of 2008-2012 from the first planning period and subtracted that from the baseline as the progress made since the first planning period. "Progress since the first planning period" should instead reflect the whole first period and the difference between the 2000-2004 baseline period and the 2014-2018 period. "Progress to date" should include visibility progress beyond the 2014-2018 five year average to reflect progress made since the first planning period. For example, at a minimum current progress to date should be the

difference between the 2000-2004 baseline and the 2015-2019 period which extends beyond the first planning period.

- For section 3.3 and 3.4, which discusses light extinction IMPROVE monitoring trends, Figures 3-2 to 3-9 show aerosol species contributing to light extinction only includes data up to 2018. IMPROVE data beyond 2018 is readily available and should be used to reflect the second planning period. We recommend that NMED update these figures to reflect the more recent IMPROVE data that is currently available beyond the first planning period. For example, the 2015-2019 period extends beyond the first planning period and would be acceptable to use for current IMPROVE data for the aerosol species to reflect the second planning period.
- For section 3.6, which discusses the uniform rate of progress (URP) at New Mexico's Class I areas, and sections 9.2 to 9.3 which describes future most impaired and clearest days at New Mexico's Class I areas, we recommend that NMED include quantifiable numbers or tables in the narrative to explain the key data in figures 3-10 to 3-17; figures 9-1 to 9-8; and 9-9 to 9-16. The quantifiable data for the graphs are readily available and should be included in the narrative to explain the symbols on the graphs. For example, we recommend including quantifiable numbers in the narrative explaining the projected 2028 URP values for the most impaired and clearest days, the 2000-2004 baseline values, the future 2028 RPG values, the modeled 2028 SIP control values, and the 2064 natural conditions. Other comparisons like difference in adjusted and unadjusted values would be beneficial as well.

Costs:

"Margin of Safety"

> *"SCR retrofits require significant physical space (e.g., for catalyst beds, ducting, etc.) and therefore often involve extensive building and/or exhaust system modifications which can easily cost as much if not more than the SCR equipment itself. To account for the possibility, if not likelihood, that implementing SCR would involve significant ancillary costs, NMED determined that SCR should only be required for reasonable progress if its estimate of the total capital investment (TCI) for SCR includes a "margin of safety" of at least 100 percent, except in cases where its estimate of TCI for SCR expressly includes costs for building/exhaust system modifications."*
> *In this context, the margin of safety is equal to (TCI @ $10,000/ton – Estimated TCI) / Estimated TCI.*

- NMED's approach to SCR cost evaluation applies a "margin of safety" of 100%, which EPA believes is unsupported. In other words, SCR was only found to be cost-effective if the cost was below $5,000/ton because NMED assumes that ancillary costs not accounted for would result in costs up to 100% of the estimated SCR costs. This is similar to applying a retrofit difficulty factor of two to the cost of SCR, where a factor of one reflects the average costs of a typical installation. NMED should document any physical space limitations at the facilities, necessary modifications to a building's structure to accommodate SCR, or required modifications to existing ductwork and estimate the capital costs of associated with these modifications in implementing SCR rather than relying on a "margin of safety" approach. These costs should be incorporated into the detailed capital cost estimates and/or incorporated into justification for an appropriate retrofit factor. NMED should also discuss and more fully document the cost estimation methodology and the items included in the

capital cost that may already include estimates for the necessary modifications, the retrofit difficulty factor, and any contingency costs already included.

- In addition, NMED should consider the incremental costs and reductions between controls when multiple controls are in a cost-effective range.

- NMED did not provide Appendix D for review at this time, therefore, EPA is not able to provide a complete review of the cost information. Detailed cost analysis information for each control evaluated should be provided for review as part of the proposed SIP.

Source Selection:

- In Section 6.3 which discusses the Q/d analysis, EPA recommends that NMED provide a spreadsheet of the actual analysis to document the Q/d conclusion for how the sources were selected. Although a table was provided to show the 24 facilities that were screened in for selection, NMED should provide the source selection spreadsheet data to show where the sources were selected from. EPA also recommends providing more recent information, if available, to show that the most recent data still supports the source selection analysis.
- In Section 6.2 (p. 95)[1] NMED states that due to the lack of emissions information for minor stationary sources and area sources in NMED's and EHD's jurisdictions, NMED and EHD decided to conduct a source selection process for major (Title V) sources only. Under the Regional Haze Rule, States should consider evaluating major and minor stationary sources, mobile sources, and area sources in developing the long-term strategy (40 CFR 51.308(f)(2)(i)). We recommend that the SIP provide additional justification for limiting the evaluation to only Title V sources (point sources).
- EPA recommends that NMED provide more discussion for how the tier two PTE screening basis on p. 101-102 was determined. In other words, how did NMED determine that a four-factor analysis would only be required on individual equipment with a PTE greater than 10 pph of NO_X or SO_2?

Miscellaneous:

- Because EPA was not provided Appendix E, we were unable to assess NMED's consultation with other states, including Texas. It is also unclear from the SIP Narrative (Chapter 10) what resulted from the consultation specific to the Salt Creek robust analysis to address impacts demonstrated from Texas. Please provide additional discussion of consultation specific to Texas sources that may impact Salt Creek as part of the robust analysis.
- EPA recommends providing a discussion on environmental justice in the SIP. EPA's clarifications memo encourages consideration of whether there may be equity and

[1] Additionally, in FN 154 of the SIP Narrative, NMED states, "NMED and EHD lack detailed emissions inventory data for minor stationary sources and area sources for the current Regional Haze planning period. Sufficient statewide data was not available to adequately assess the potential visibility impact of such sources at Class I Areas. Therefore, NMED and EHD chose not to evaluate minor stationary sources or area sources for potential new control measures in the current Regional Haze planning period. Minor stationary sources and area sources may be addressed in future planning periods or addressed through other rule makings."

environmental justice impacts when developing regional haze strategies for the second planning period.

- Please differentiate between the emission reductions achieved through implementation of this SIP and emission reductions that have already occurred due to source shutdowns.

Note: These comments are in response to NMED's draft SIP Narrative and NMED's draft Appendix C. On p. xv, NMED notes "In addition to the main SIP narrative provided in Chapters 1-12, this SIP revision includes a number of appendices providing reference materials, technical support, and documentation. These include WRAP's emission inventory and modeling references (Appendices A and B), NMED's four-factor analyses and control measures determinations technical support document (Appendix C), and documentation related to NMED's four-factor analyses (Appendix D) and coordination and consultations (Appendix E)." The EPA has not reviewed the additional appendices in early engagement.

From:	Feldman, Michael
To:	Jones, Mark, ENV; Grady, James; Goudeau, Charlotte; Martinez, Michael
Cc:	Miller, Kenneth, ENV; Sanchez, Alex, ENV; Butt, Neal, ENV; Hirsch, Josh, ENV; Vigil, Christopher J, ENV; Donaldson, Guy
Subject:	[EXTERNAL] RE: Deadline has moved to Monday, Sept. 9th, 5:00 pm (MDT) to provide feedback/suggestions on the NMED draft new Regional Haze rule
Date:	Monday, September 9, 2024 3:04:02 PM

CAUTION: This email originated outside of our organization. Exercise caution prior to clicking on links or opening attachments.

Mark - In response to your request below for informal comments by COB today, we were able to review the proposed rulemaking language and provide the comments below for your consideration. Please let us know if you have any questions. We will have opportunity to discuss at our regularly scheduled call tomorrow.

EPA Comments to NMED for New Rule 20.68 NMAC:

- 20.2.68.104 NMAC provides that certain emission testing (Subparts GG, IIII, JJJJ, and KKKK of 40 CFR 60 performance standards and Subparts ZZZZ and DDDDD of 40 CFR 63 NESHAPS) may satisfy the testing requirements for this part if the required testing is consistent with 20.2.68.104 NMAC and occurs at least once per calendar year. NMED should provide more information regarding how facilities will demonstrate that the emissions testing referenced (Parts 60 and 63) is consistent with the requirements of 20.2.68.104 NMAC.
- NMED should provide more information in the SIP narrative regarding the specific emission reductions from the retired units in Table 2.
- NMED should add more explanation in the SIP narrative to explain how the various emission limits in Table 1 were chosen. The narrative does not clearly explain how NMED arrived at the numerical limits for the various units. For example, for Blanco Compressor Station A, NMED does not clearly identify how it arrived at the 0.5 g/bhp-hr rate for each of the new units. Some of this information is found in footnotes to Table 8-1 or in the appendices but should be clearly identified in discussion of the four factor-analysis and control determination summary.
- NMED should provide discussion and justification in the SIP narrative for the compliance deadlines listed for each of the emission limitations in the rule.
- 20.2.68.102 C specifies that compliance for Cunningham units is determined on a 30-day rolling basis and 20.2.68.102 D specifies compliance with the multi-unit limitations for Mountainair and Roswell to be determined on a 12-month rolling average. For clarity, please also specify in 20.2.68.102 how compliance will be determined for all other emission limitations in Table 1.
- Under 20.2.68.104, for clarity please separate the discussion and equation for units with g/bhp-hr emission limits into a separate item rather than combined under B.
- Please include in 20.2.68.104 a description of how compliance with the 12-month rolling average will be demonstrated for Roswell and Mountainair units. Does this include calculation of emissions based on 12-month time of operations or fuel usage data for the units under the multi-unit limit?
- Consistent with 20.2.68.104 B.(1), recordkeeping requirements under 20.2.68.105 should include requirements to record specific data as required during testing such as load and other parameters used to demonstrate compliance with the limitations.

Thank you and the NMED RH team for all the work on this SIP package and for developing this draft rule language.

Michael Feldman, PhD
Section Supervisor, SO2 and Regional Haze
Air and Radiation Division
U.S. EPA Region 6

Regional Haze Planning Team
NMED Air Quality Bureau | www.env.nm.gov/air-quality/
mark.jones@env.nm.gov | (505) 629-6626

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E.4 Discussions with Tribes

Supporting documentation for NMED coordination with New Mexico Tribes, Pueblos, and Nations is provided below. The following documents are included in this section (in reading order):

- NMED Communications
    - Letters to Tribes, Pueblos and Nations on Engagement Opportunity (6/6/24)
    - Overview of Plan for Tribes, Nations and Pueblos (6/18/24)
- Tribes, Nations, Pueblo Comments
    - Ute Mountain Ute Tribe (UMUT) Comment Cover Letter (7/19/24)
    - UMUT Comments (7/19/24)

DocuSign Envelope ID: 32853558-7CF9-4D96-A7CB-9BECDA187150

June 6, 2024

Pueblo of Acoma
Governor Randall Vicente
PO Box 309
Acoma, NM, 87034
governor@poamail.org

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Vicente,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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We are expressly seeking feedback and comments from Tribal governments in New Mexico on our plan, as it may impact Tribal Lands. A draft plan is available to you for review and comments here: https://service.web.env.nm.gov/urls/VycLCxYU. Please note, this draft is not for public distribution, and is meant for only review by representatives of Tribal government. We would also be happy to email you a copy directly or mail you a printed copy if that would be more convenient. We are also planning on holding an informational webinar for Tribal government representatives to provide an overview of the plan and answer any questions you may have if that would be of interest on June 18, 2024 from 10:30am until 12:00pm, MDT. The meeting details and link will be sent in an email closer to this date. If you are planning on attending the webinar, please contact Mark Jones at the phone number or email address provided below to inform us of your intention. We respectfully request that you provide any

[1] 40 CFR §§ 51.300-51.309.

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comments on the draft plan directly to Mark Jones by July 19, 2024. After this date, NMED will consider any comments which we have received before proceeding with public outreach.

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For additional information concerning this letter, please contact:

Mark Jones: (505) 629-6626, mark.jones@env.nm.gov

Sincerely,

DocuSigned by:
Danielle L Gilbert
BD8C44EB00D548E...

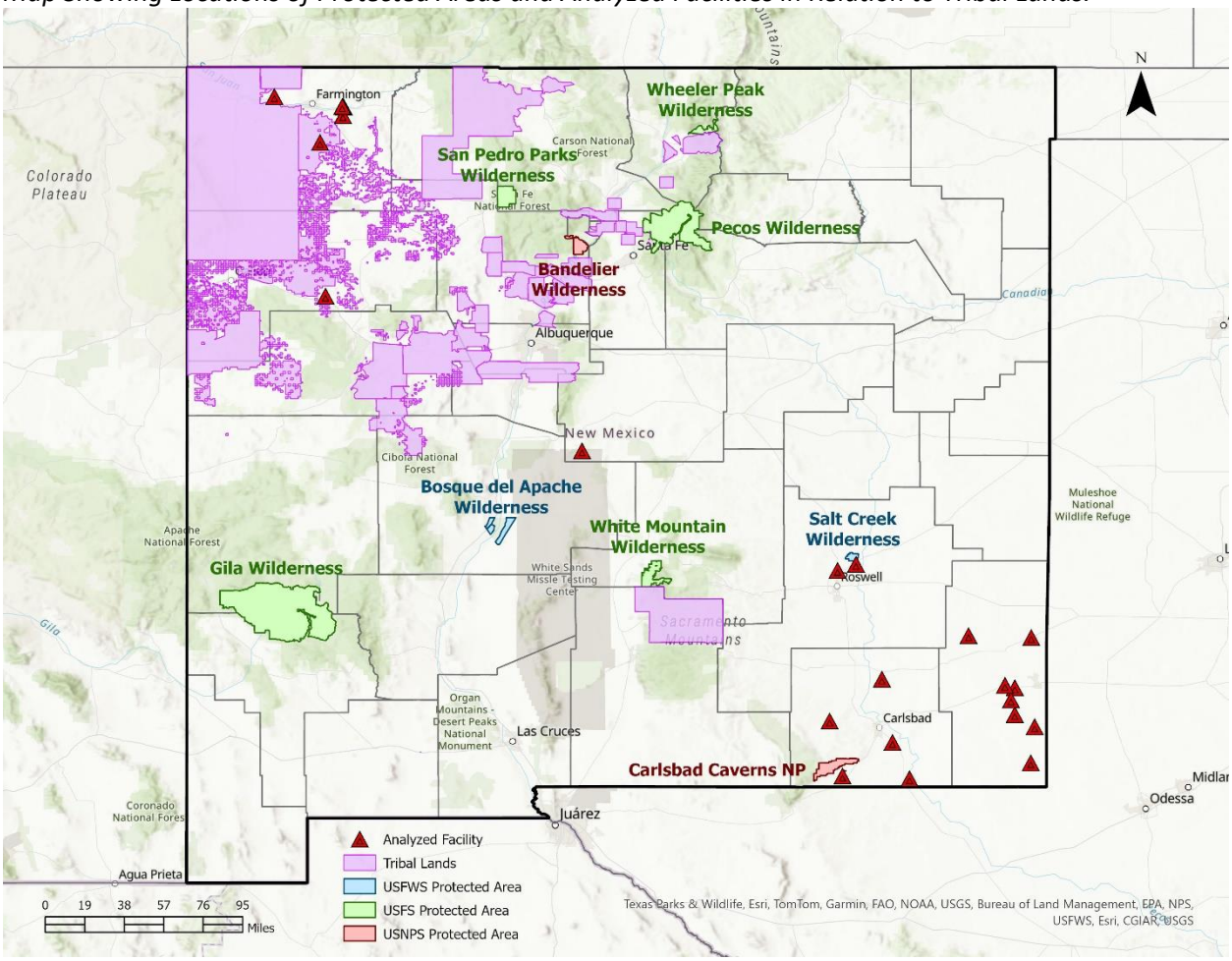
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Franklin Martinez, Environmental Director, fmartinez@poamail.org
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
Eric Peters, Control Strategies Manager, eric.peters@env.nm.gov
Kathryn S. Becker, Tribal Liaison, kathryn.becker@env.nm.gov

Enclosures: Map Showing Locations of Protected Areas and Analyzed Facilities in Relation to Tribal Lands

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June 6, 2024

Pueblo of Cochiti
Governor Joel A. Arquero
PO Box 70
Cochiti, NM, 87072
governor@cochiti.org

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Arquero,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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Mark Jones: (505) 629-6626, mark.jones@env.nm.gov

Sincerely,

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Danielle L Stelhair
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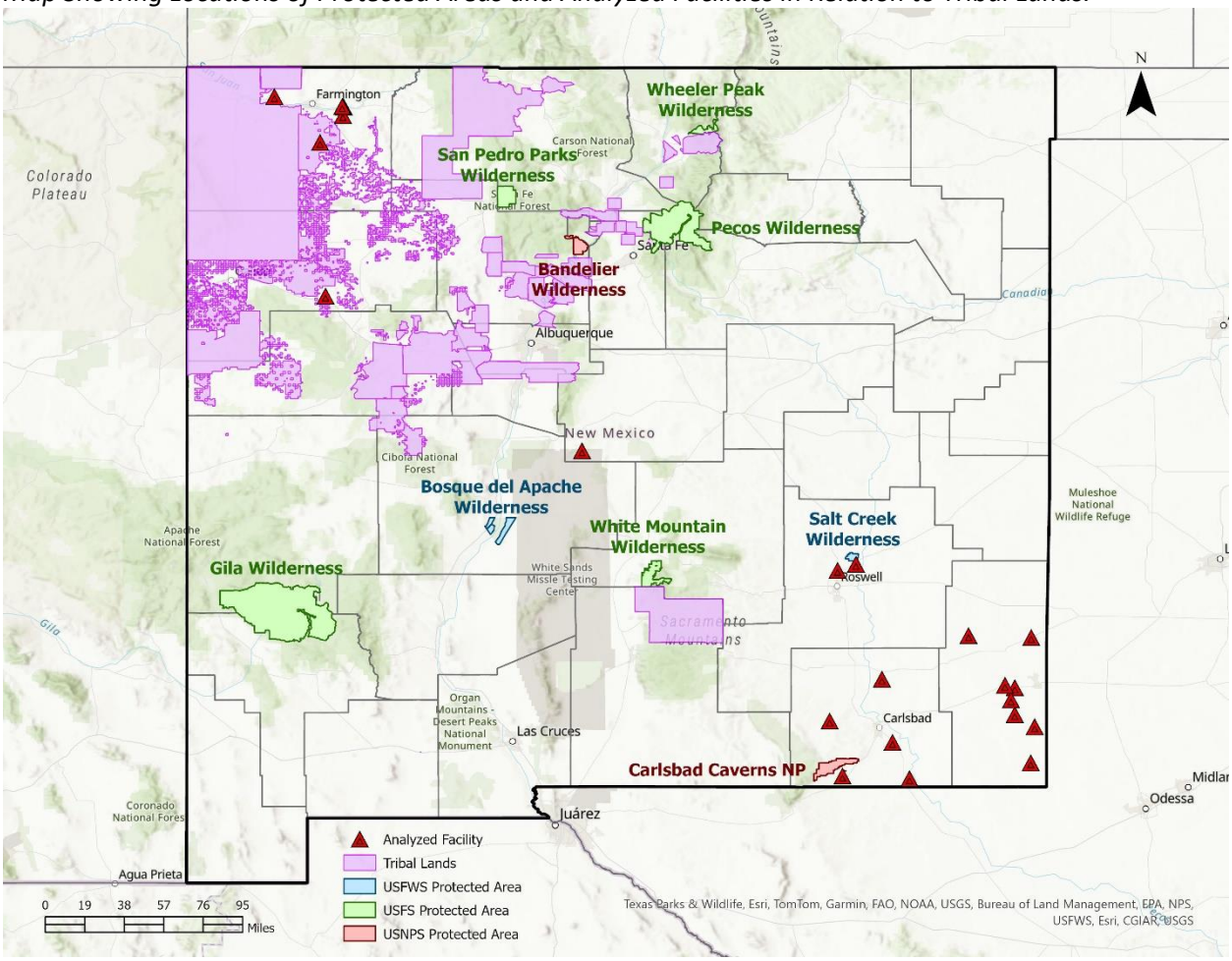
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Jayson Romero, Environmental Director, jayson.romero@cochiti.org
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
Eric Peters, Control Strategies Manager, eric.peters@env.nm.gov
Kathryn S. Becker, Tribal Liaison, kathryn.becker@env.nm.gov

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June 6, 2024

Fort Sill Apache Tribe of Oklahoma
Chairwoman Jennifer M. Heminokeky, VC
Rt. 2, Box 121
Apache, OK, 73006
jennifer.heminokeky@fortsillapache-nsn.gov

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Chairwoman Heminokeky,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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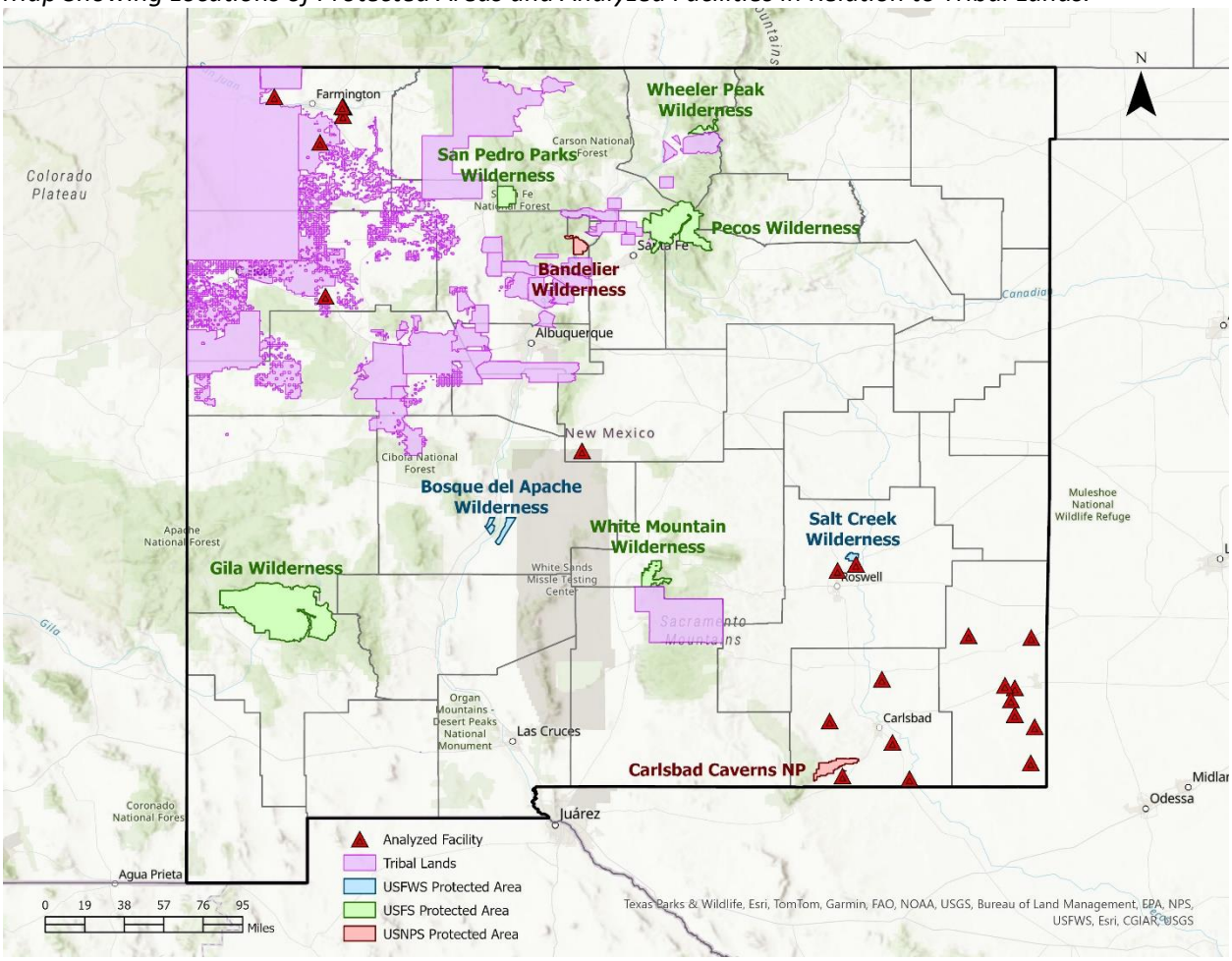
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Monte Scammahorn, Director, monte.scammahorn@fortsillapache-nsn.gov
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
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June 6, 2024

Pueblo of Isleta
Governor Max Zuni
P.O. Box 1290
Isleta Pueblo, NM, 87022
max.zuni@isletapueblo.com

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Zuni,

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Sincerely,

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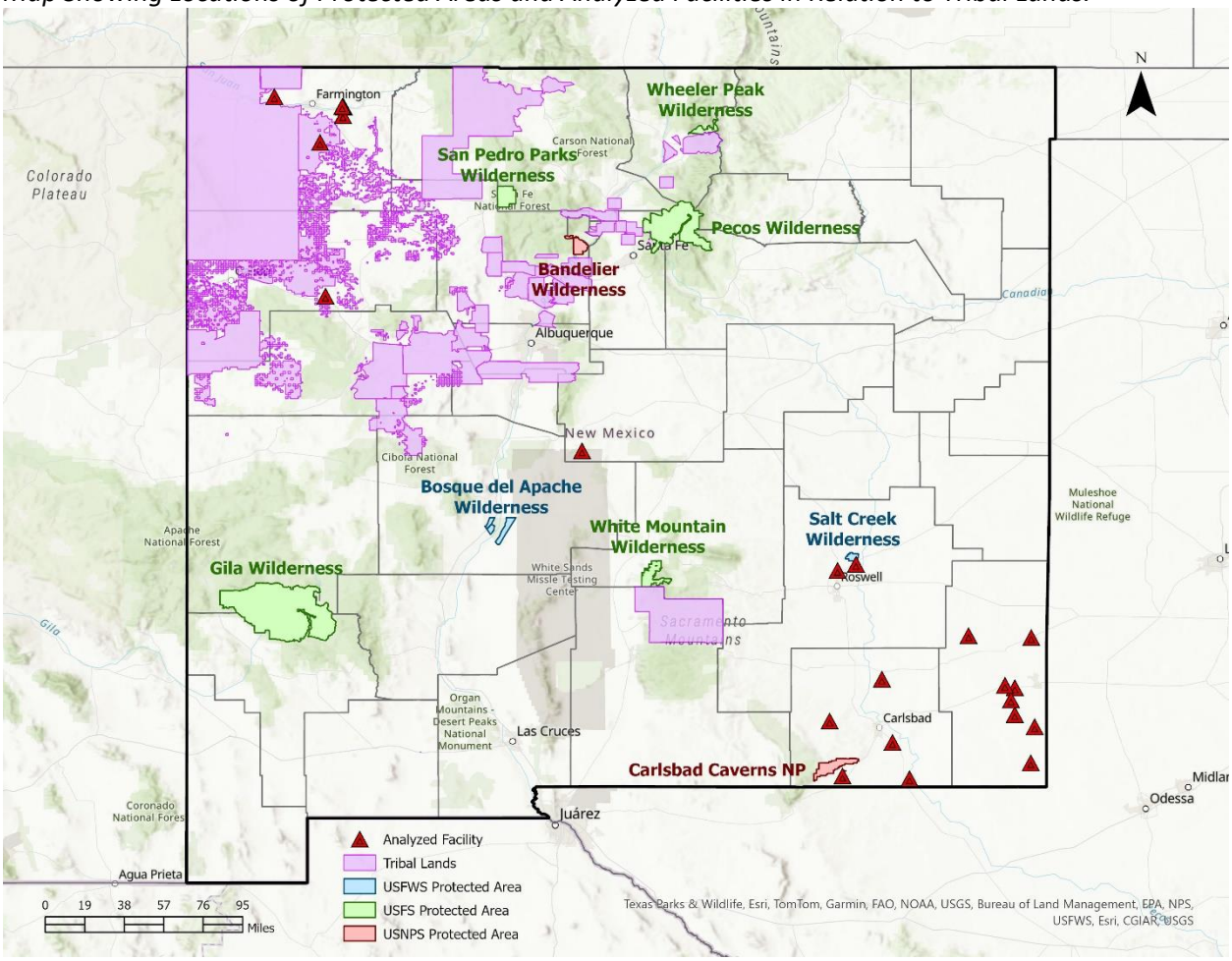
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Clint Lente, Environmental Resources Director, Clint.lente@isletapueblo.com
Ramona Montoya, Interim Environmental Director, Ramona.Montoya@Isletapueblo.com
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
Eric Peters, Control Strategies Manager, eric.peters@env.nm.gov
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June 6, 2024

Pueblo of Jemez
Governor Peter Madalena
P.O. Box 100
Jemez Pueblo, NM, 87024
raymond.loretto.dvm@jemezpueblo.org

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Madalena,

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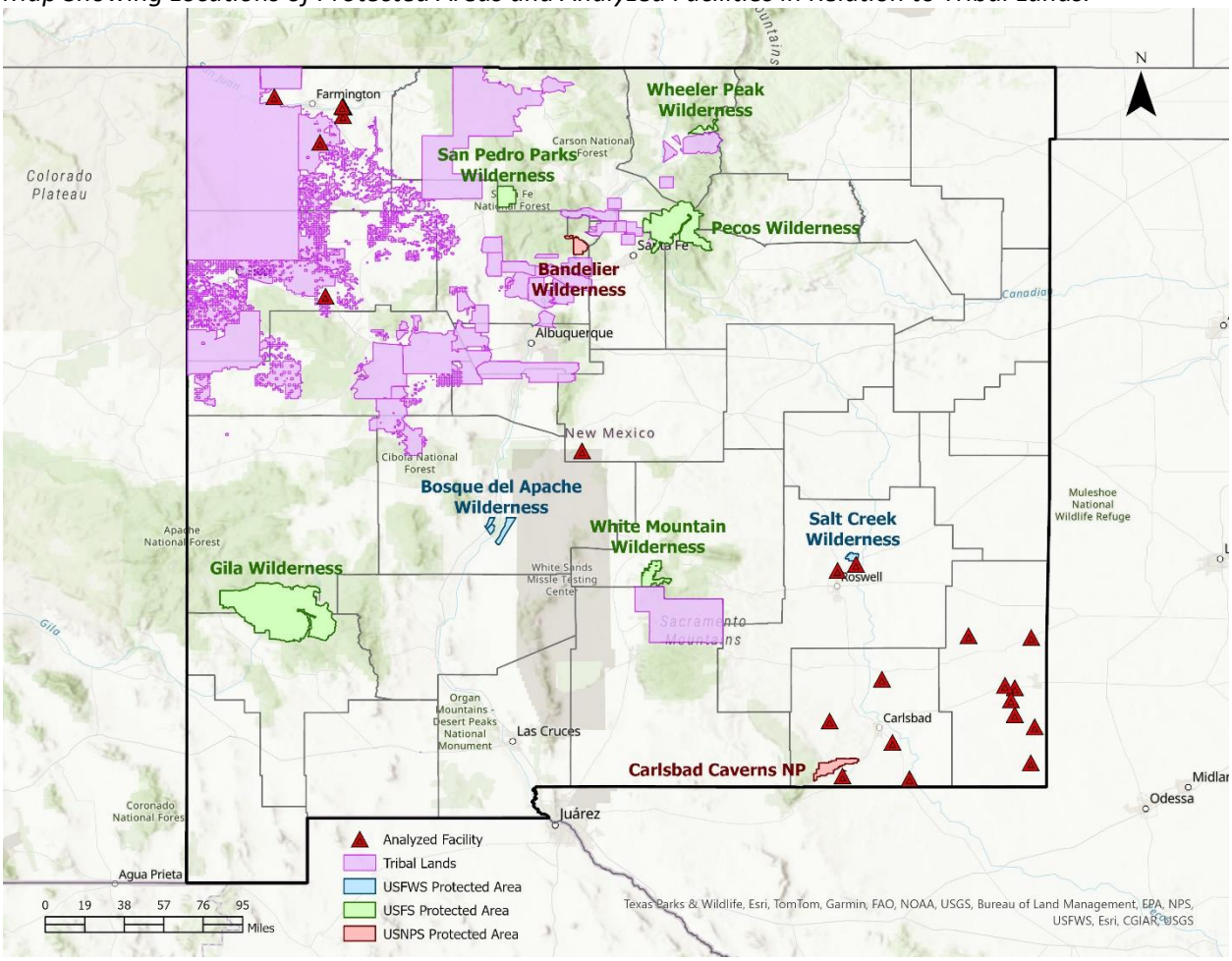
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Clarie Madalena, Director, clarice.madalena@jemezpueblo.org
Michelle Miano, Environmental Protection Division Director michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
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June 6, 2024

Jicarilla Apache Nation
President Sonja Newton
P.O. Box 507
Dulce, NM,87528
snewton.jan@gmail.com

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[1] 40 CFR §§ 51.300-51.309.

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For additional information concerning this letter, please contact:

Mark Jones: (505) 629-6626, mark.jones@env.nm.gov

Sincerely,

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Danielle L Gilbert
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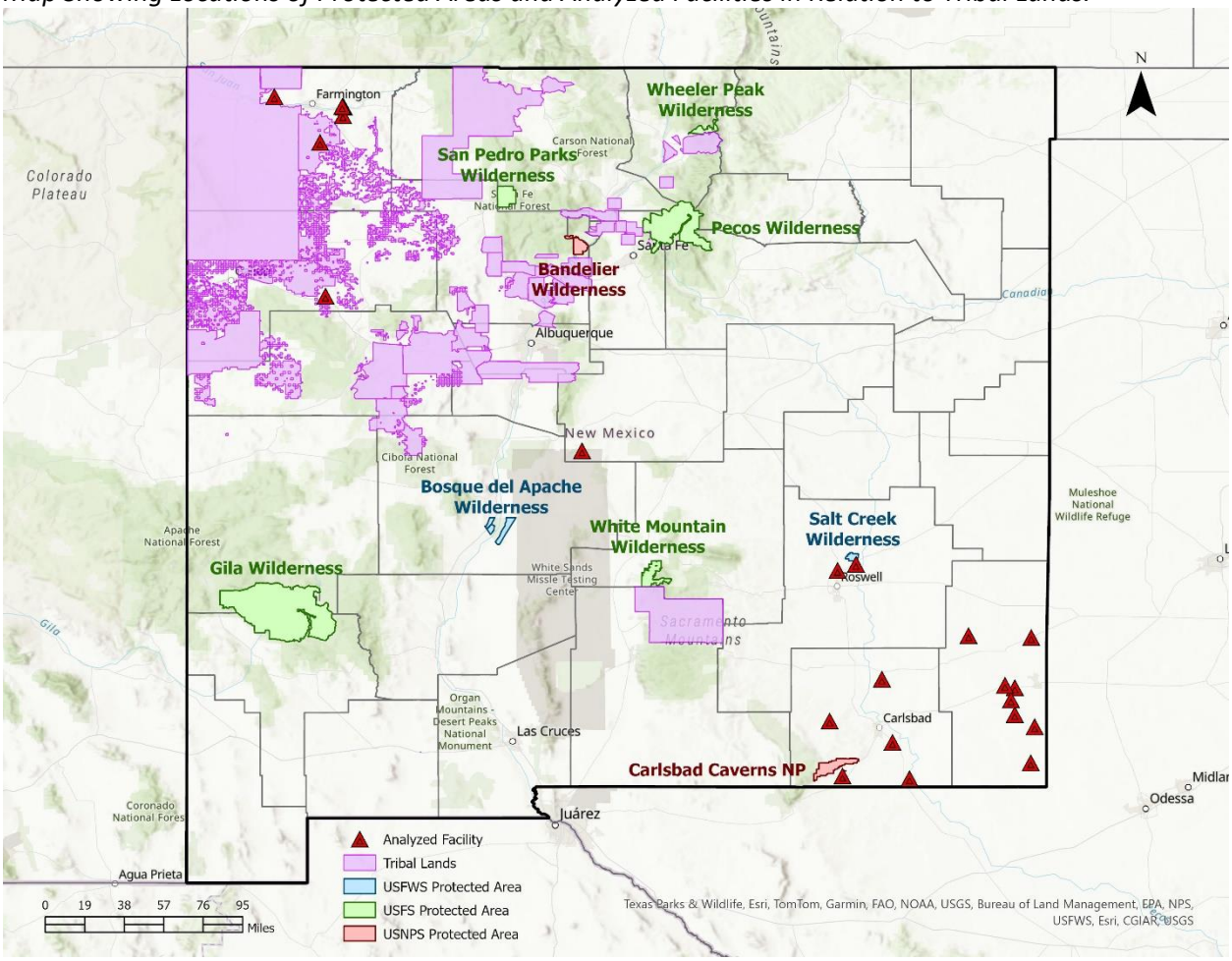
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Cordell TecCube, Program Director, cltecube@yahoo.com
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
Eric Peters, Control Strategies Manager, eric.peters@env.nm.gov
Kathryn S. Becker, Tribal Liaison, kathryn.becker@env.nm.gov

Enclosures: Map Showing Locations of Protected Areas and Analyzed Facilities in Relation to Tribal Lands

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June 6, 2024

Kewa Pueblo
Governor Frank Nieto
P.O. Box 99
Santa Domingo Pueblo, NM, 87052
beverly.garcia@kewa-nsn.us

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Nieto,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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Mark Jones: (505) 629-6626, mark.jones@env.nm.gov

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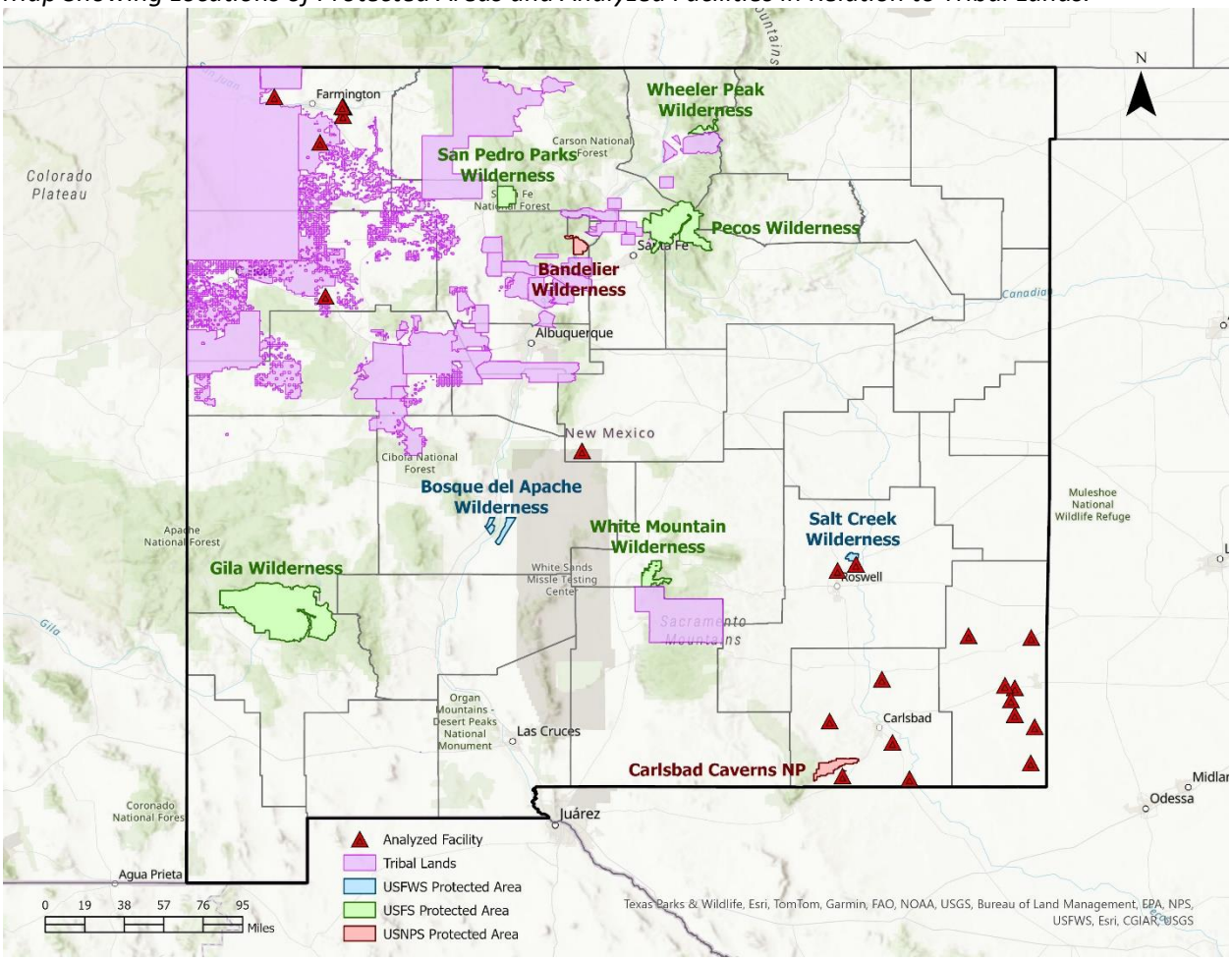
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Cody Crumbo, Environmental Director, woodrow.crumbo@kewa-nsn.us
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
Eric Peters, Control Strategies Manager, eric.peters@env.nm.gov
Kathryn S. Becker, Tribal Liaison, kathryn.becker@env.nm.gov

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June 6, 2024

Pueblo of Laguna
Governor Gaylord Siow
P.O. Box 194
Laguna Pueblo, NM, 87026
GSiow@lagunapueblo-nsn.gov

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Siow,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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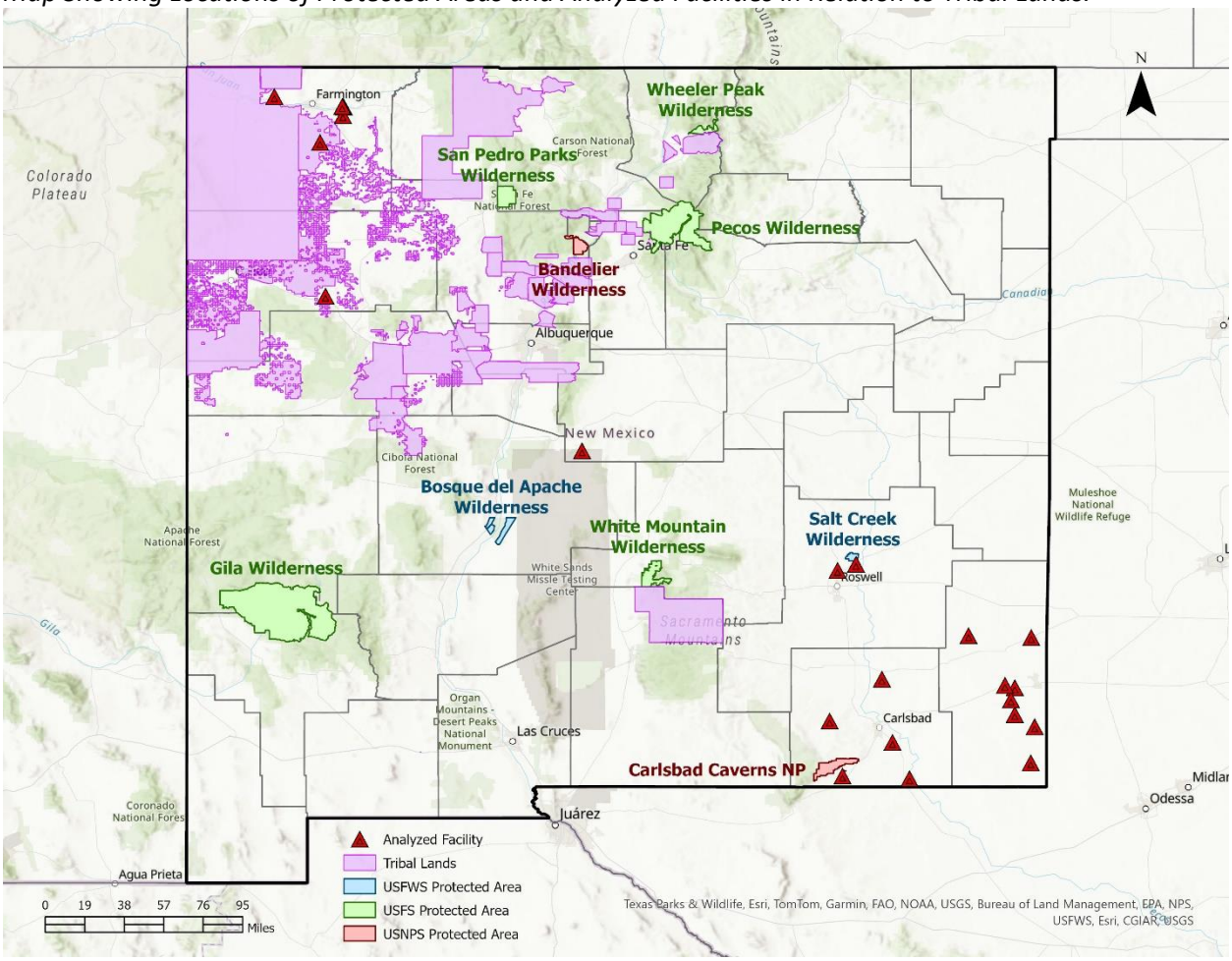
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Greg Jojola, Environmental Manager, gjojola@pol-nsn.gov
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
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June 6, 2024

Mescalero Apache Tribe
President Thora Walsh Padilla
P.O. Box 227
Mescalero, NM, 88340
emartinez@mecaleroapachetribe.com

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable President Padilla,

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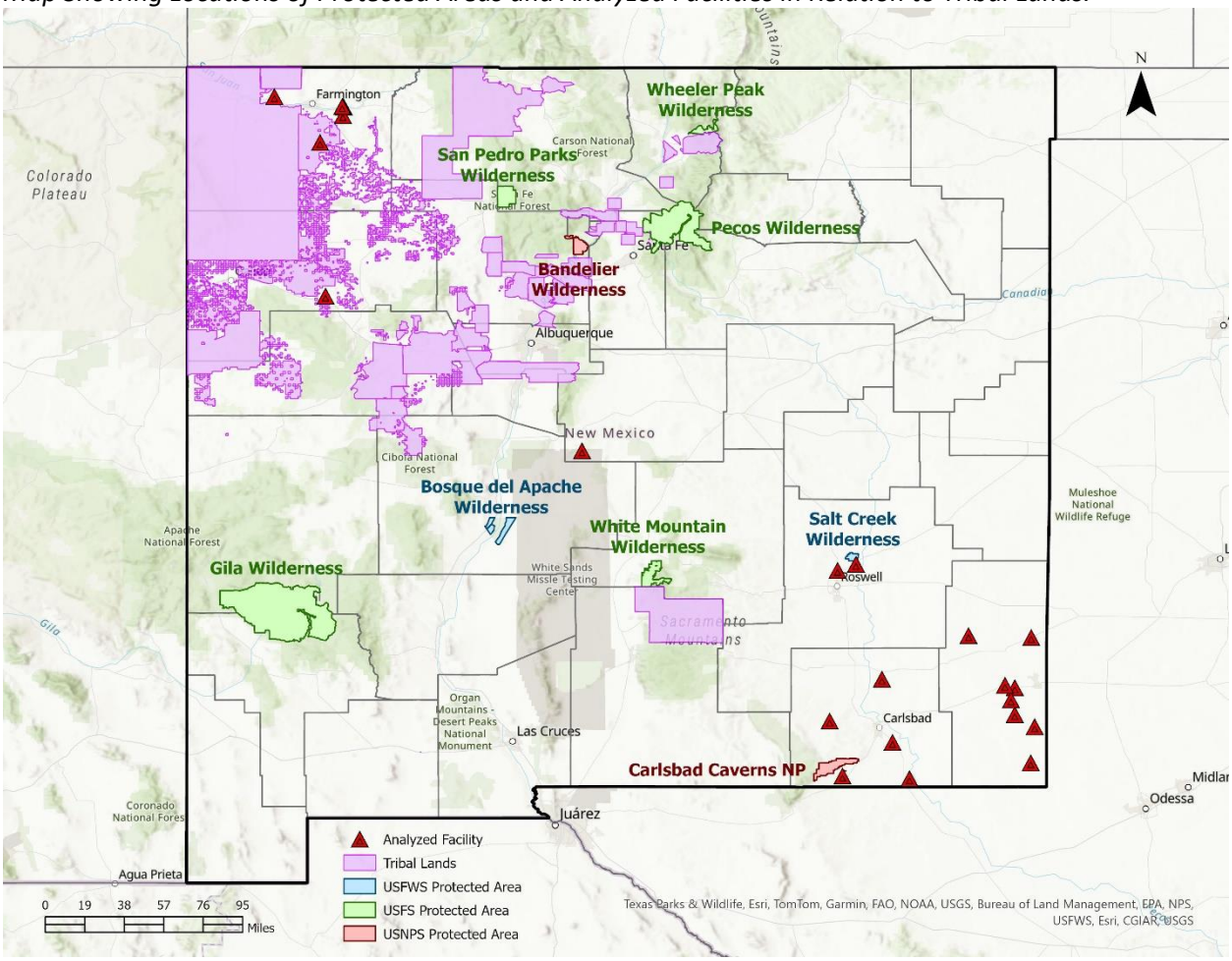
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Frizzell Frizzell, Jr., Director, Ffrizzelljr@innofthemountaingods.com
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
Eric Peters, Control Strategies Manager, eric.peters@env.nm.gov
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June 6, 2024

Pueblo of Nambe
Governor Nathaniel Porter
15A NP102 West
Santa Fe, NM, 87506
governor@nambepueblo.org

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Porter,

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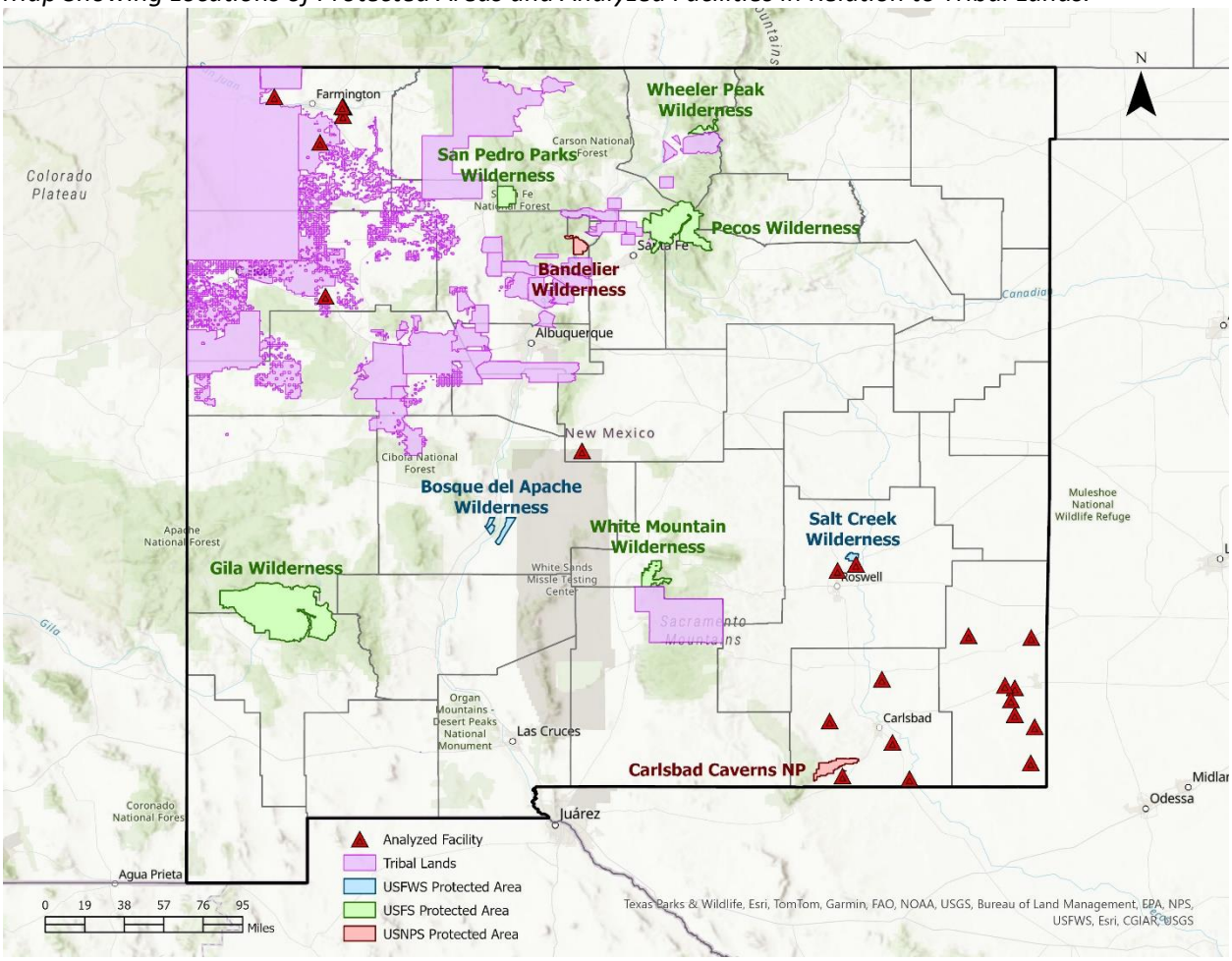
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Victoria Atencio, Environmental and Natural Resource Manager, vatencio@nambepueblo.org
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
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June 6, 2024

Navajo Nation Council
Speaker Crystalyne Curley
P.O. Box 3390
Window Rock, AZ, 86515
crystalyne.curley@navajo-nsn.gov

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Speaker Curley,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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We are expressly seeking feedback and comments from Tribal governments in New Mexico on our plan, as it may impact Tribal Lands. A draft plan is available to you for review and comments here: https://service.web.env.nm.gov/urls/VycLCxYU. Please note, this draft is not for public distribution, and is meant for only review by representatives of Tribal government. We would also be happy to email you a copy directly or mail you a printed copy if that would be more convenient. We are also planning on holding an informational webinar for Tribal government representatives to provide an overview of the plan and answer any questions you may have if that would be of interest on June 18, 2024 from 10:30am until 12:00pm, MDT. The meeting details and link will be sent in an email closer to this date. If you are planning on attending the webinar, please contact Mark Jones at the phone number or email address provided below to inform us of your intention. We respectfully request that you provide any

[1] 40 CFR §§ 51.300-51.309.

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For additional information concerning this letter, please contact:

Mark Jones: (505) 629-6626, mark.jones@env.nm.gov

Sincerely,

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Danielle L Gallegos
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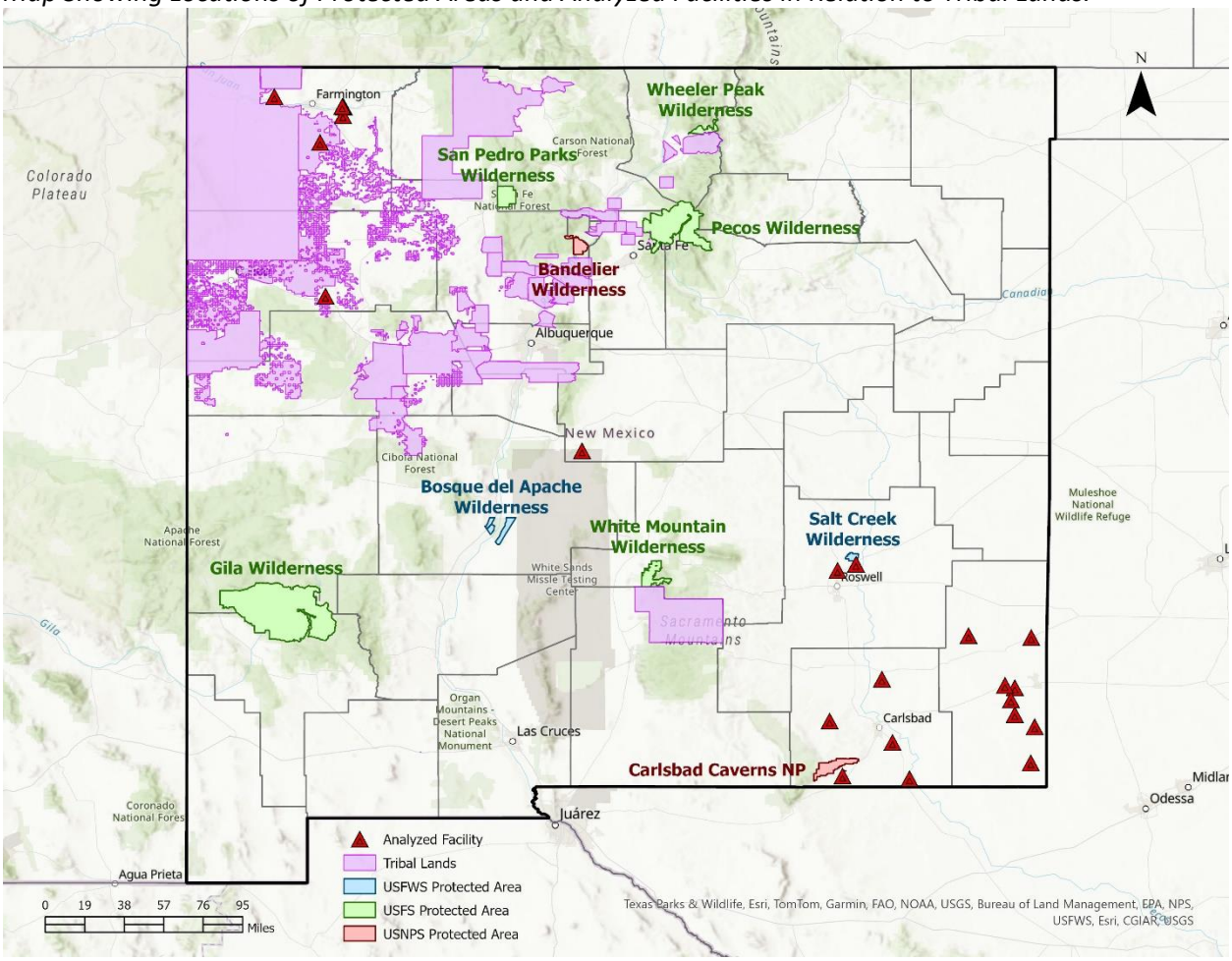
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Stephen Etsitty, EPA Executive Director, s.etsitty@navajo-nsn.gov
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
Eric Peters, Control Strategies Manager, eric.peters@env.nm.gov
Kathryn S. Becker, Tribal Liaison, kathryn.becker@env.nm.gov

Enclosures: Map Showing Locations of Protected Areas and Analyzed Facilities in Relation to Tribal Lands

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Map Showing Locations of Protected Areas and Analyzed Facilities in Relation to Tribal Lands.



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June 6, 2024

Navajo Nation
President Buu Nygren
P.O. Box 7440
Window Rock, AZ, 86515
buunygren@navajo-nsn.gov

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable President Nygren,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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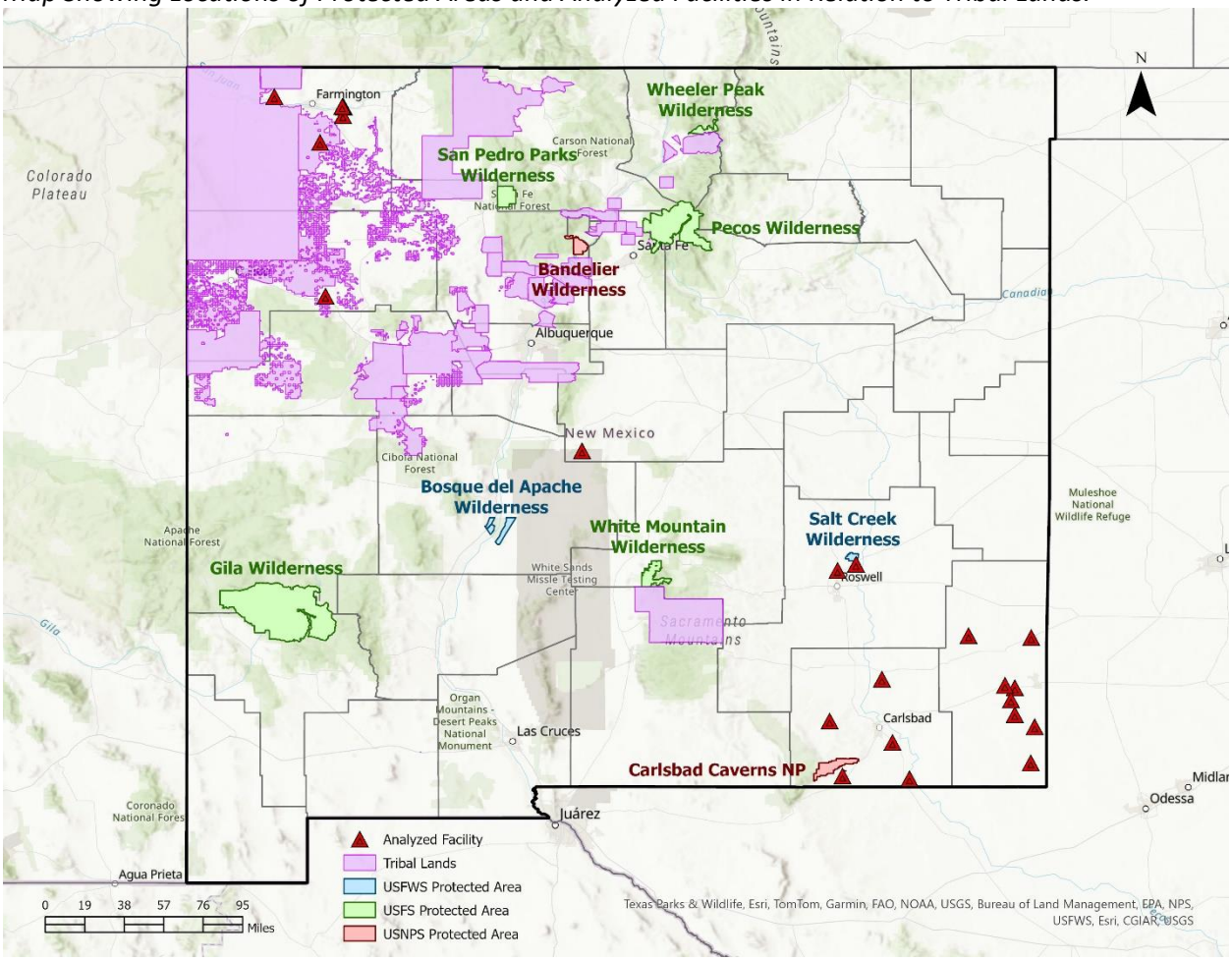
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Stephen Etsitty, EPA Executive Director, s.etsitty@navajo-nsn.gov
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
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June 6, 2024

Pueblo of Ohkay Owingeh
Governor Larry Phillips, Jr.
P.O. Box 1099
Ohkay Owingeh, NM, 87566
governor@ohkay.org

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Phillips,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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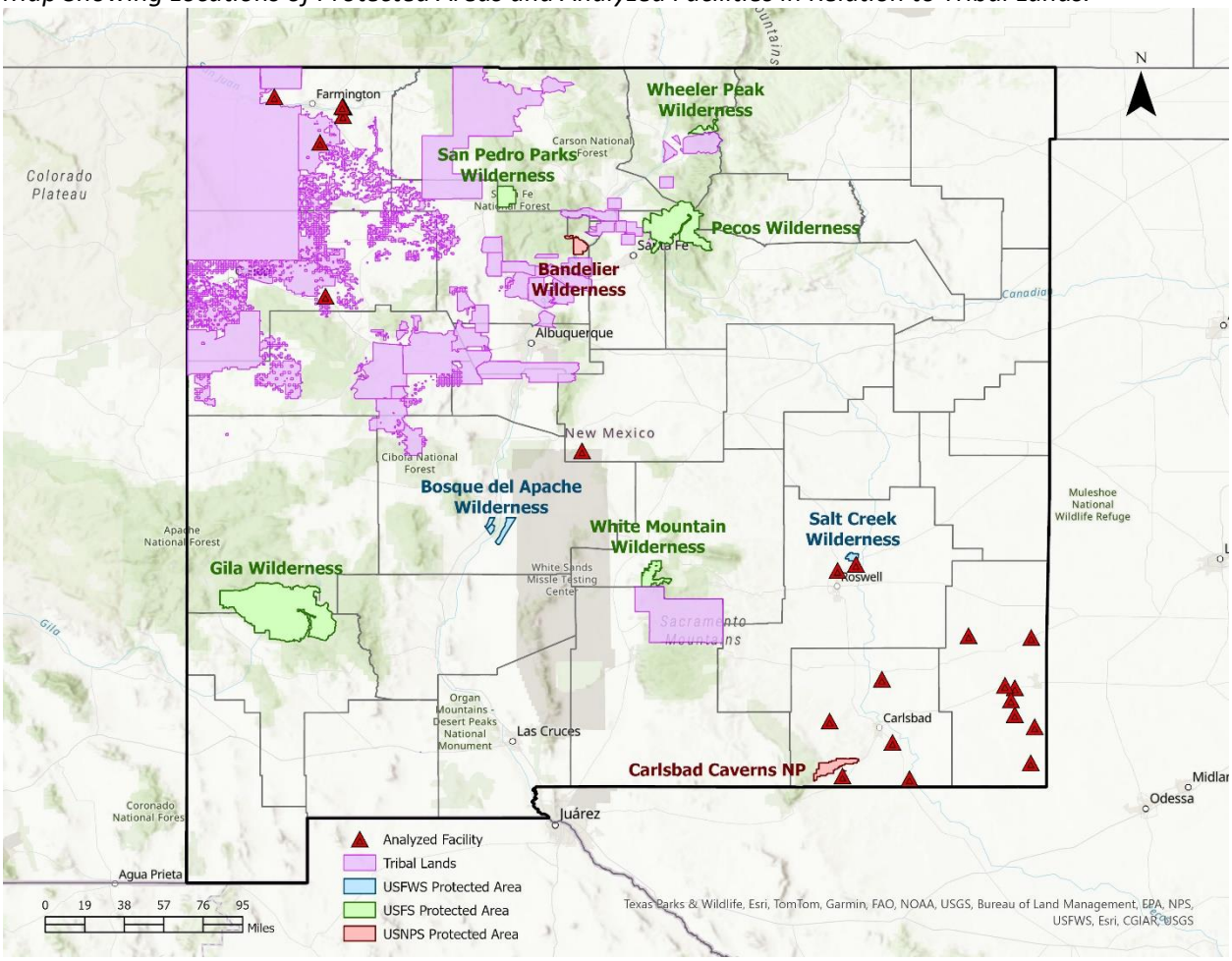
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
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June 6, 2024

Pueblo of Picuris
Governor Craig Quanchello
P.O. Box 127
Penasco, NM, 87553
governor@picurispueblo.org

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Quanchello,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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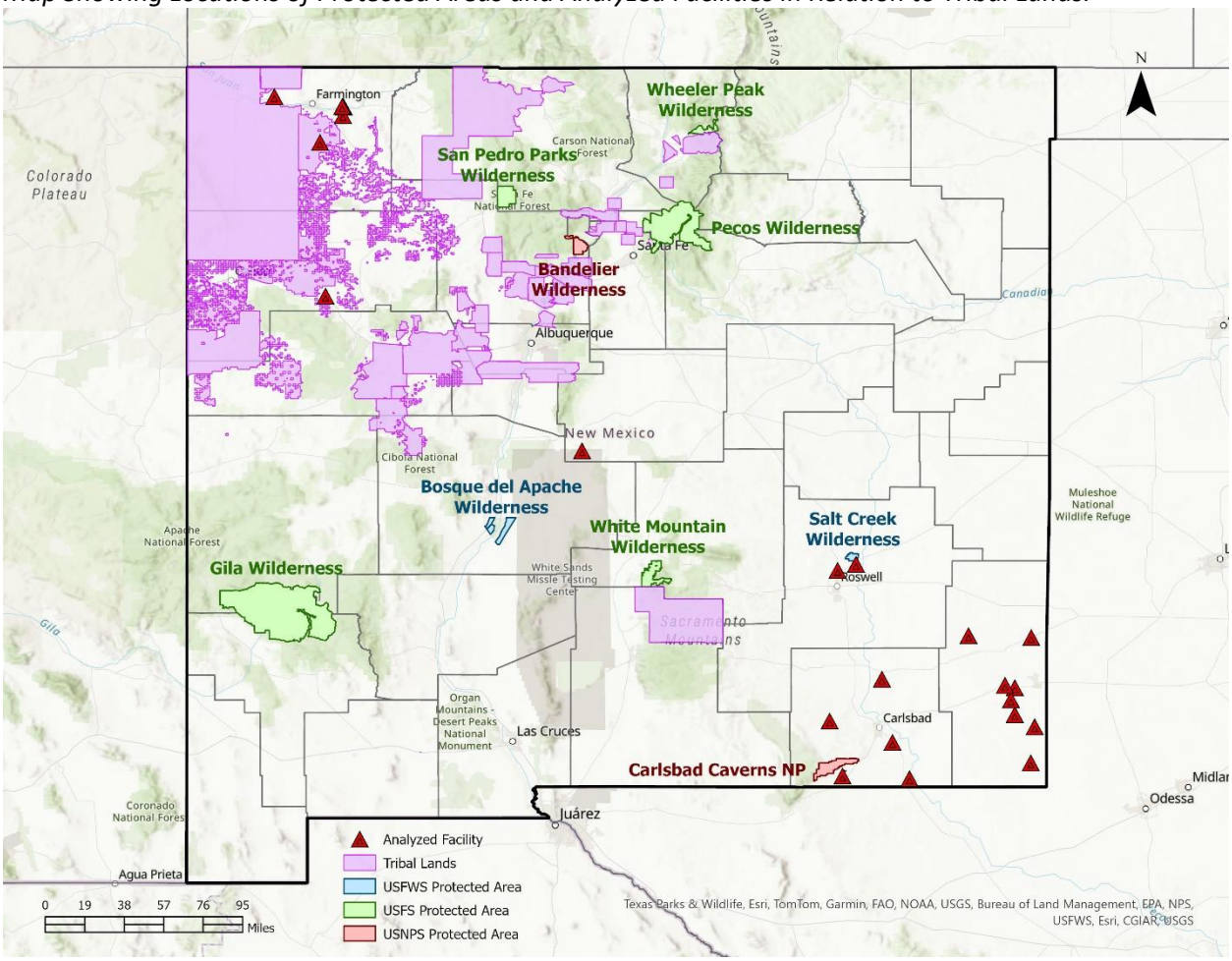
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Adrian Montoya, environment@picurispueblo.org.
Pueblo of Picuris Env. Admin., administrativeassistantppe@picurispueblo.org
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
Eric Peters, Control Strategies Manager, eric.peters@env.nm.gov
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June 6, 2024

Pueblo of Pojoaque
Governor Jenelle Roybal
78 Cities of Gold Road, Santa Fe, NM, 87506
Penasco, NM, 87553
governor@pojaque.org

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Roybal,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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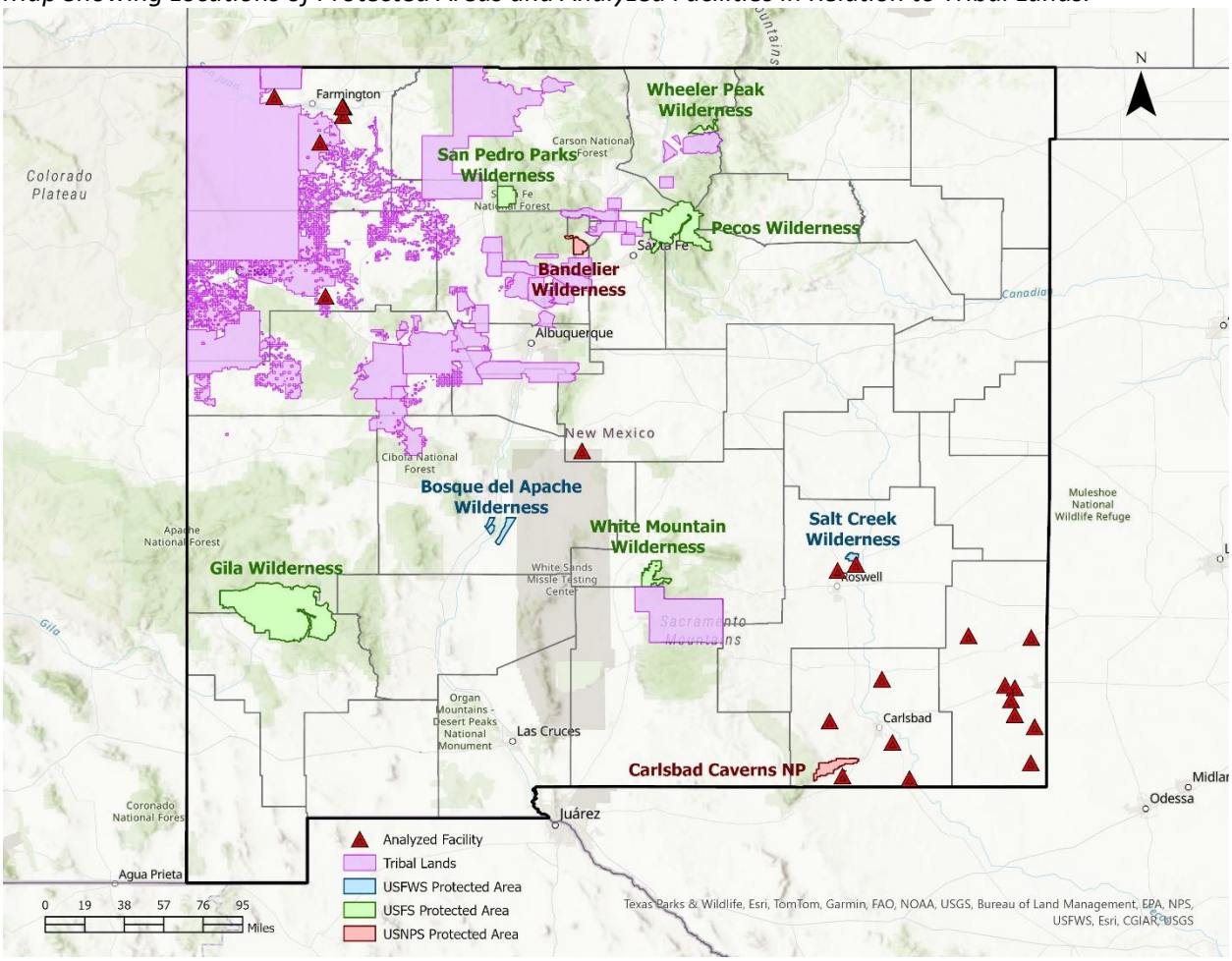
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Adam Duran, Director, aduran@pojaque.org
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
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June 6, 2024

Pueblo of San Felipe
Governor Anthony Ortiz
P.O. Box 4339
San Felipe Pueblo, NM, 87001
gov.ortiz@sfpueblo.com

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Ortiz,

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We are expressly seeking feedback and comments from Tribal governments in New Mexico on our plan, as it may impact Tribal Lands. A draft plan is available to you for review and comments here: https://service.web.env.nm.gov/urls/VycLCxYU. Please note, this draft is not for public distribution, and is meant for only review by representatives of Tribal government. We would also be happy to email you a copy directly or mail you a printed copy if that would be more convenient. We are also planning on holding an informational webinar for Tribal government representatives to provide an overview of the plan and answer any questions you may have if that would be of interest on June 18, 2024 from 10:30am until 12:00pm, MDT. The meeting details and link will be sent in an email closer to this date. If you are planning on attending the webinar, please contact Mark Jones at the phone number or email address provided below to inform us of your intention. We respectfully request that you provide any

[1] 40 CFR §§ 51.300-51.309.

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For additional information concerning this letter, please contact:

Mark Jones: (505) 629-6626, mark.jones@env.nm.gov

Sincerely,

DocuSigned by:
Danielle L Gilbert
BD8C44EB00D548E...

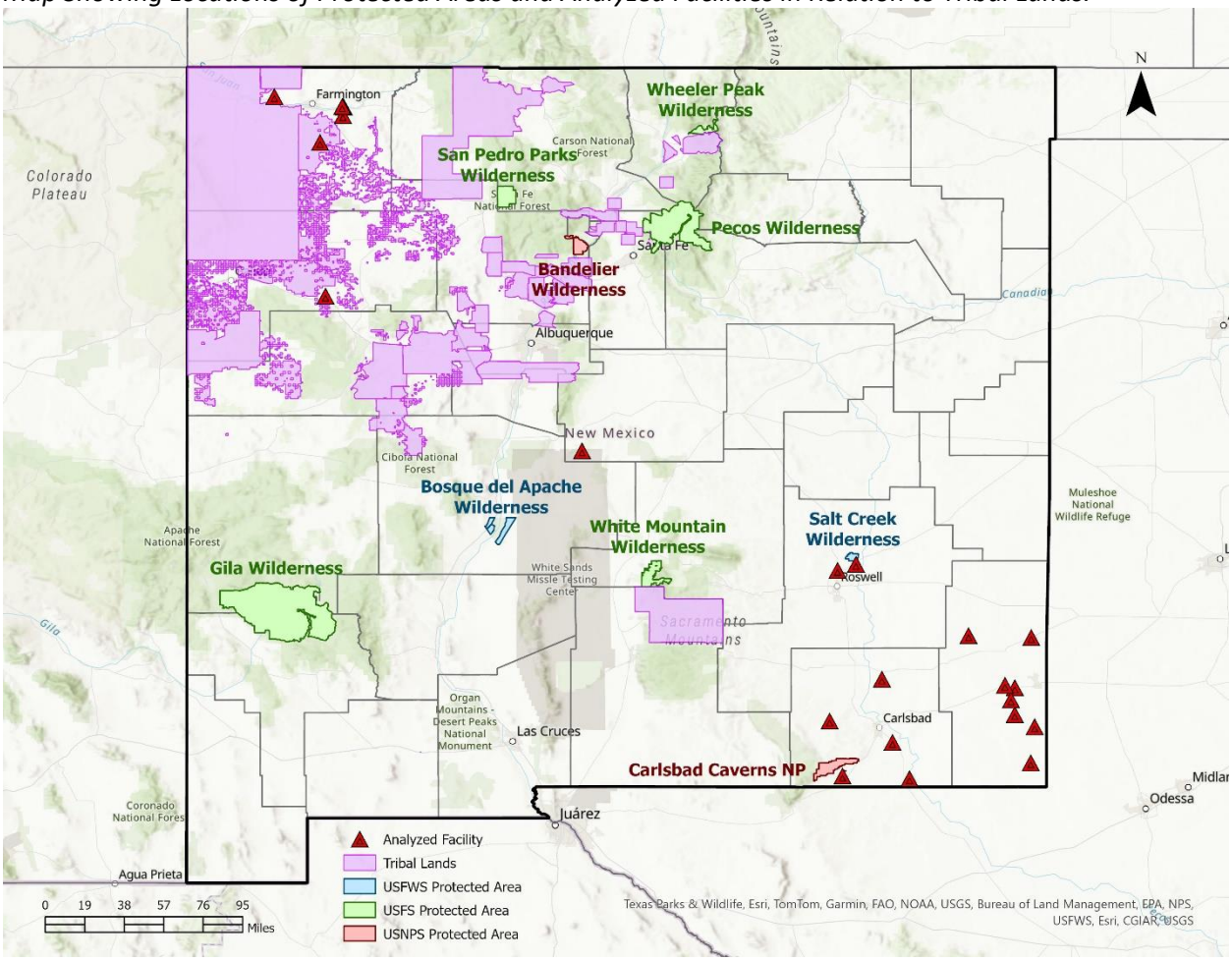
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Pinu'u Stout, Director, pstout@sfpueblo.com
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
Eric Peters, Control Strategies Manager, eric.peters@env.nm.gov
Kathryn S. Becker, Tribal Liaison, kathryn.becker@env.nm.gov

Enclosures: Map Showing Locations of Protected Areas and Analyzed Facilities in Relation to Tribal Lands

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Map Showing Locations of Protected Areas and Analyzed Facilities in Relation to Tribal Lands.



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June 6, 2024

Pueblo of San Ildefonso
Governor Christopher Moquino
02 Tunyo Po
Santa Fe, NM, 87506
governor@sanipueblo.org

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Moquino,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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For additional information concerning this letter, please contact:

Mark Jones: (505) 629-6626, mark.jones@env.nm.gov

Sincerely,

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Danielle L Gallegos
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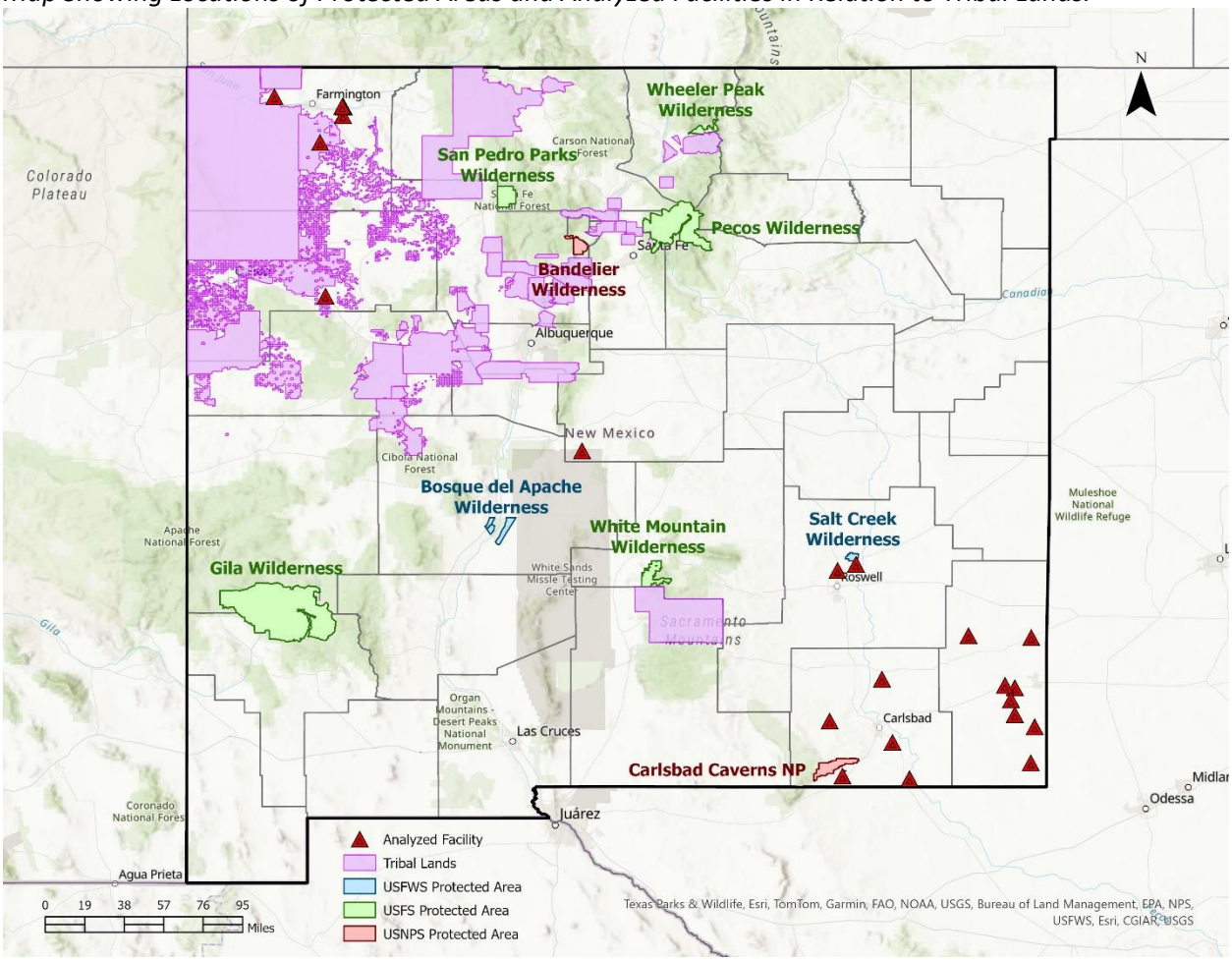
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Raymond Martinez, Director, rmartinez@sanipueblo.org
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
Eric Peters, Control Strategies Manager, eric.peters@env.nm.gov
Kathryn S. Becker, Tribal Liaison, kathryn.becker@env.nm.gov

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June 6, 2024

Pueblo of Sandia
Governor Feliz L. Chaves
481 Sandia Loop
Bernalillo, NM, 87004
gov.chaves@sandiapueblo.nsn.us

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Chaves,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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Mark Jones: (505) 629-6626, mark.jones@env.nm.gov

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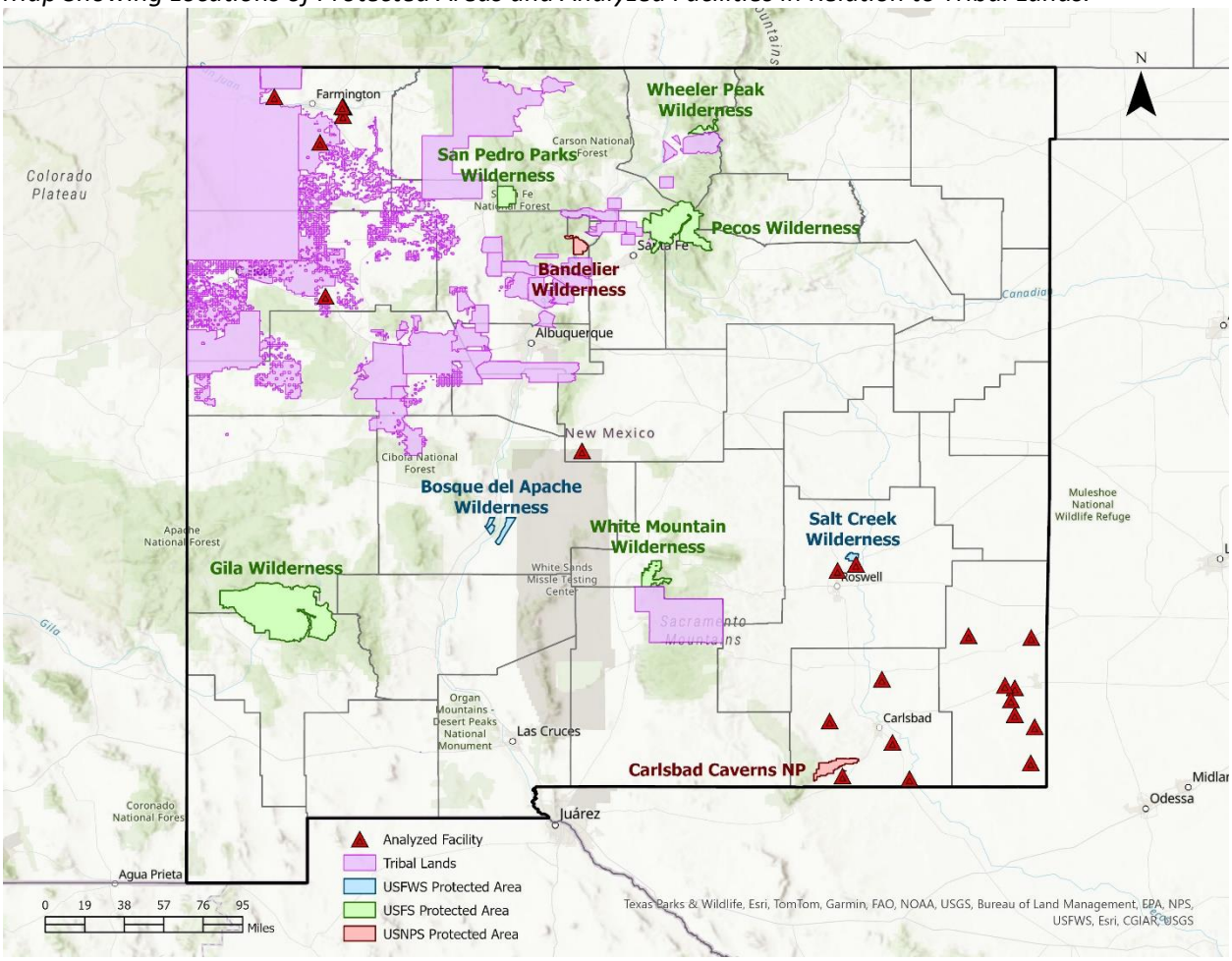
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Greg Kaufman, Environmental Director, gkaufman@sandiapueblo.nsn.us
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
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June 6, 2024

Pueblo of Santa Ana
Governor Myron Armijo
2 Dove Road
Santa Ana Pueblo, NM, 87004
governor@santaana-nsn.us

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Armijo,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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Mark Jones: (505) 629-6626, mark.jones@env.nm.gov

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Danielle L Gallegos
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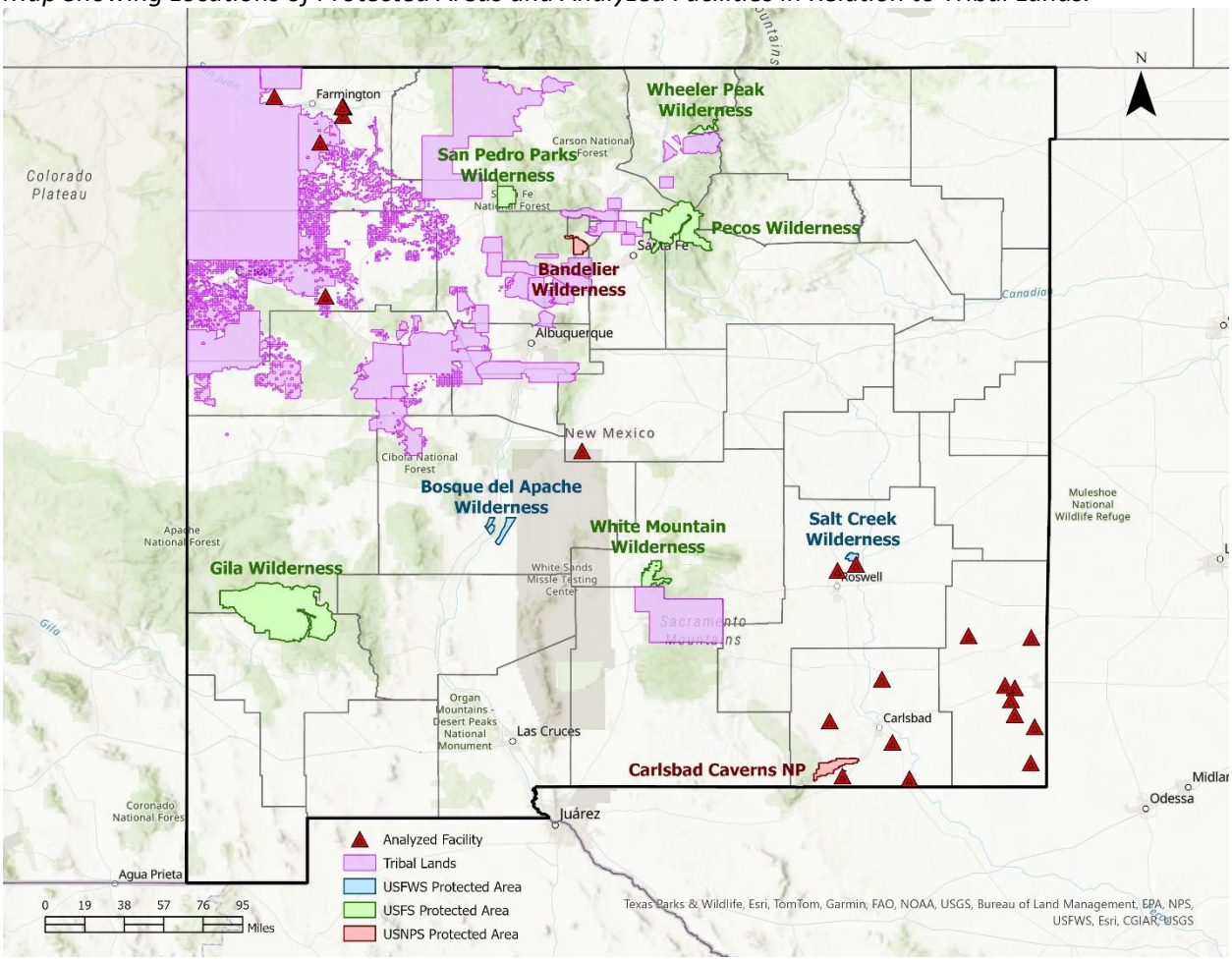
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Doug McKenna, Director of Natural Resource Department, doug.mckenna@santaana-nsn.gov
Lisa Hopinkah, Division Manager, Air Program, lisa.hopinkah@santaana-nsn.gov
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
Eric Peters, Control Strategies Manager, eric.peters@env.nm.gov
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June 6, 2024

Pueblo of Santa Clara
Governor J. Michael Chavarria
P.O. Box 580
Espanola, NM, 87532
governor@santaclarapueblo.org

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Chavarria,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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For additional information concerning this letter, please contact:

Mark Jones: (505) 629-6626, mark.jones@env.nm.gov

Sincerely,

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Danielle L Stelhair
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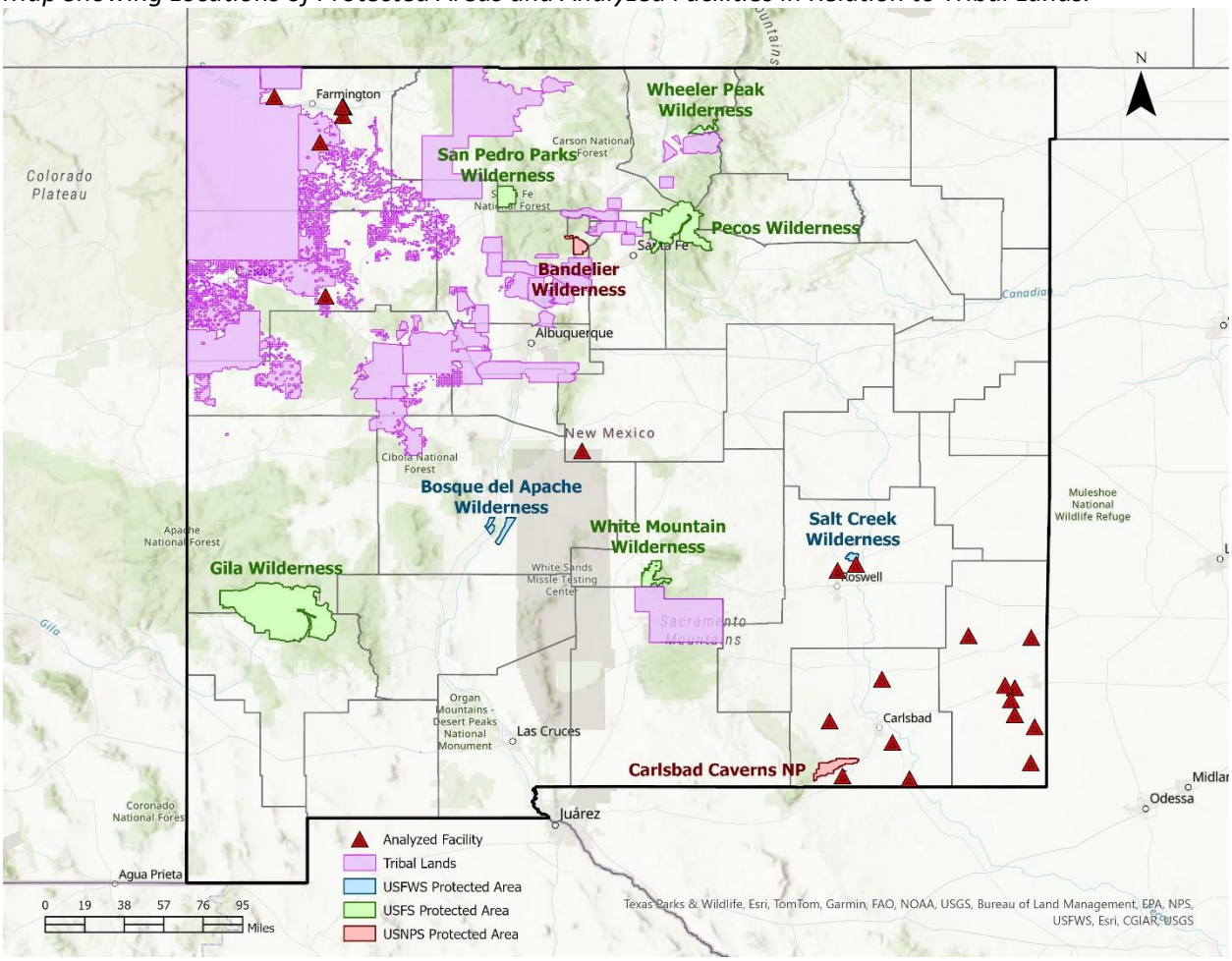
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Dino Chavarria, Director, dinoc@santaclarapueblo.org
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
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June 6, 2024

Pueblo of Taos
Governor Fred L. Romero
P.O. Box 1846
Taos, NM, 87571
governor@taospueblo.com

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Romero,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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We are expressly seeking feedback and comments from Tribal governments in New Mexico on our plan, as it may impact Tribal Lands. A draft plan is available to you for review and comments here: https://service.web.env.nm.gov/urls/VycLCxYU. Please note, this draft is not for public distribution, and is meant for only review by representatives of Tribal government. We would also be happy to email you a copy directly or mail you a printed copy if that would be more convenient. We are also planning on holding an informational webinar for Tribal government representatives to provide an overview of the plan and answer any questions you may have if that would be of interest on June 18, 2024 from 10:30am until 12:00pm, MDT. The meeting details and link will be sent in an email closer to this date. If you are planning on attending the webinar, please contact Mark Jones at the phone number or email address provided below to inform us of your intention. We respectfully request that you provide any

[1] 40 CFR §§ 51.300-51.309.

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For additional information concerning this letter, please contact:

Mark Jones: (505) 629-6626, mark.jones@env.nm.gov

Sincerely,

DocuSigned by:
Danielle L. Gallegos
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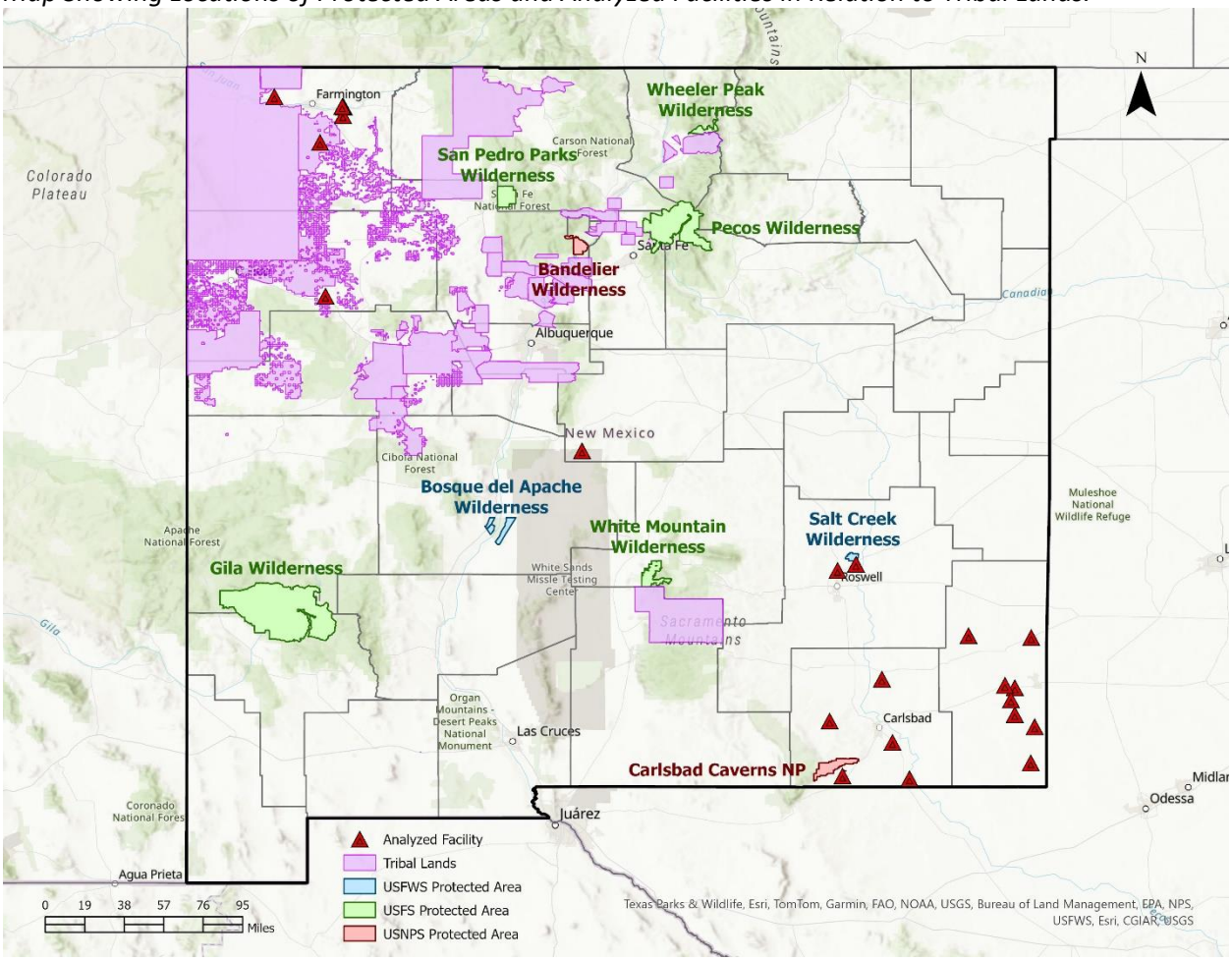
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Miguel Vigil, Environmental Manager, mvigil@taospueblo.com
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
Eric Peters, Control Strategies Manager, eric.peters@env.nm.gov
Kathryn S. Becker, Tribal Liaison, kathryn.becker@env.nm.gov

Enclosures: Map Showing Locations of Protected Areas and Analyzed Facilities in Relation to Tribal Lands

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June 6, 2024

Pueblo of Tesuque
Governor Milton Herrera
Route 42, Box 360-T
Santa Fe, NM, 87506
governor@puebloftesuque.org

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Herrera,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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Mark Jones: (505) 629-6626, mark.jones@env.nm.gov

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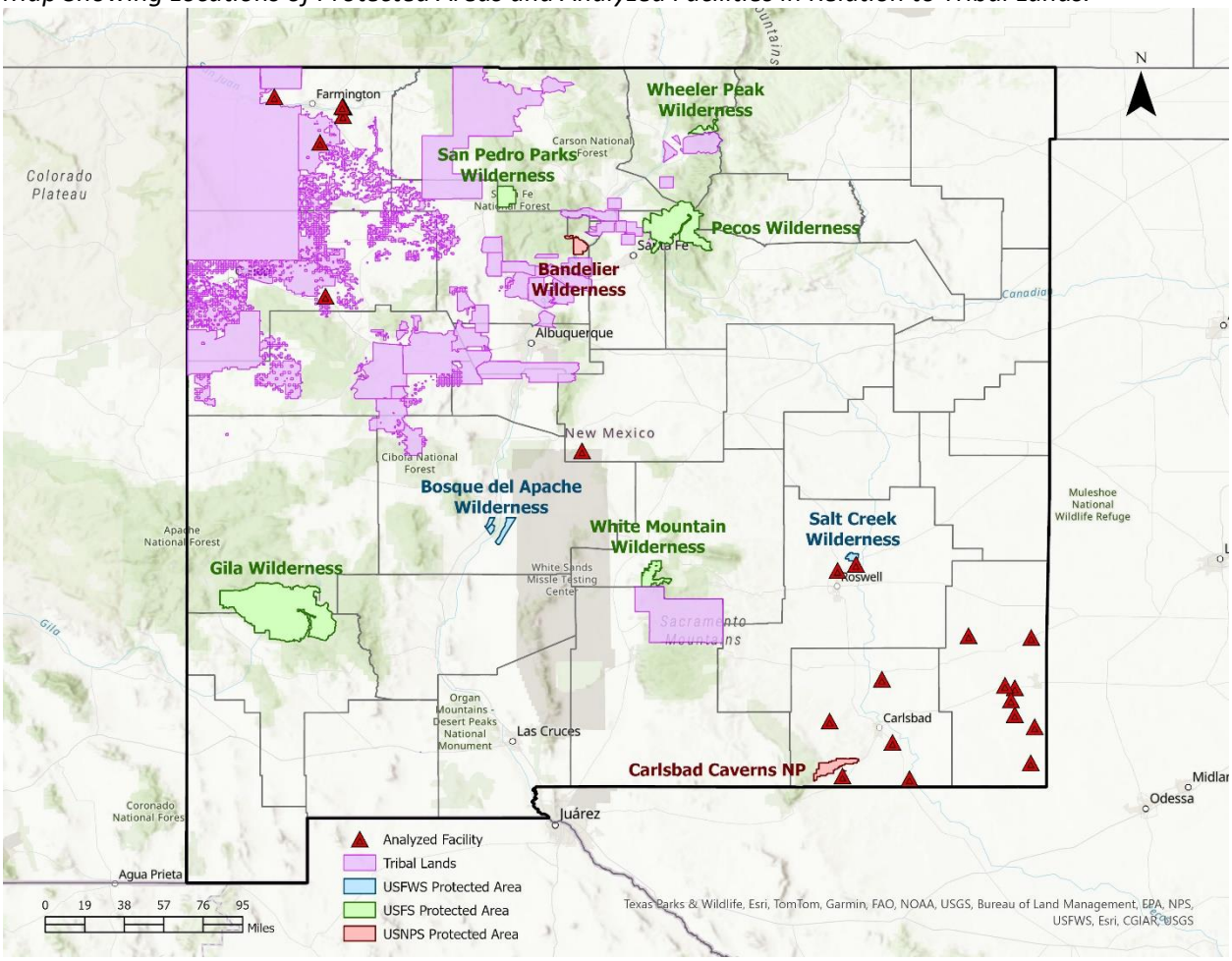
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Sage Mountainflower, Director, Pueblo of Tesuque Department of Environment and Natural Resources, sagem@pueblooftesuque.org
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
Eric Peters, Control Strategies Manager, eric.peters@env.nm.gov
Kathryn S. Becker, Tribal Liaison, kathryn.becker@env.nm.gov

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June 6, 2024

Ute Mountain Ute Tribe
Chairman Manuel Heart
P.O. Drawer JJ
Towaoc, CO, 81334
mheart@utemountain.org

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Chairman Heart,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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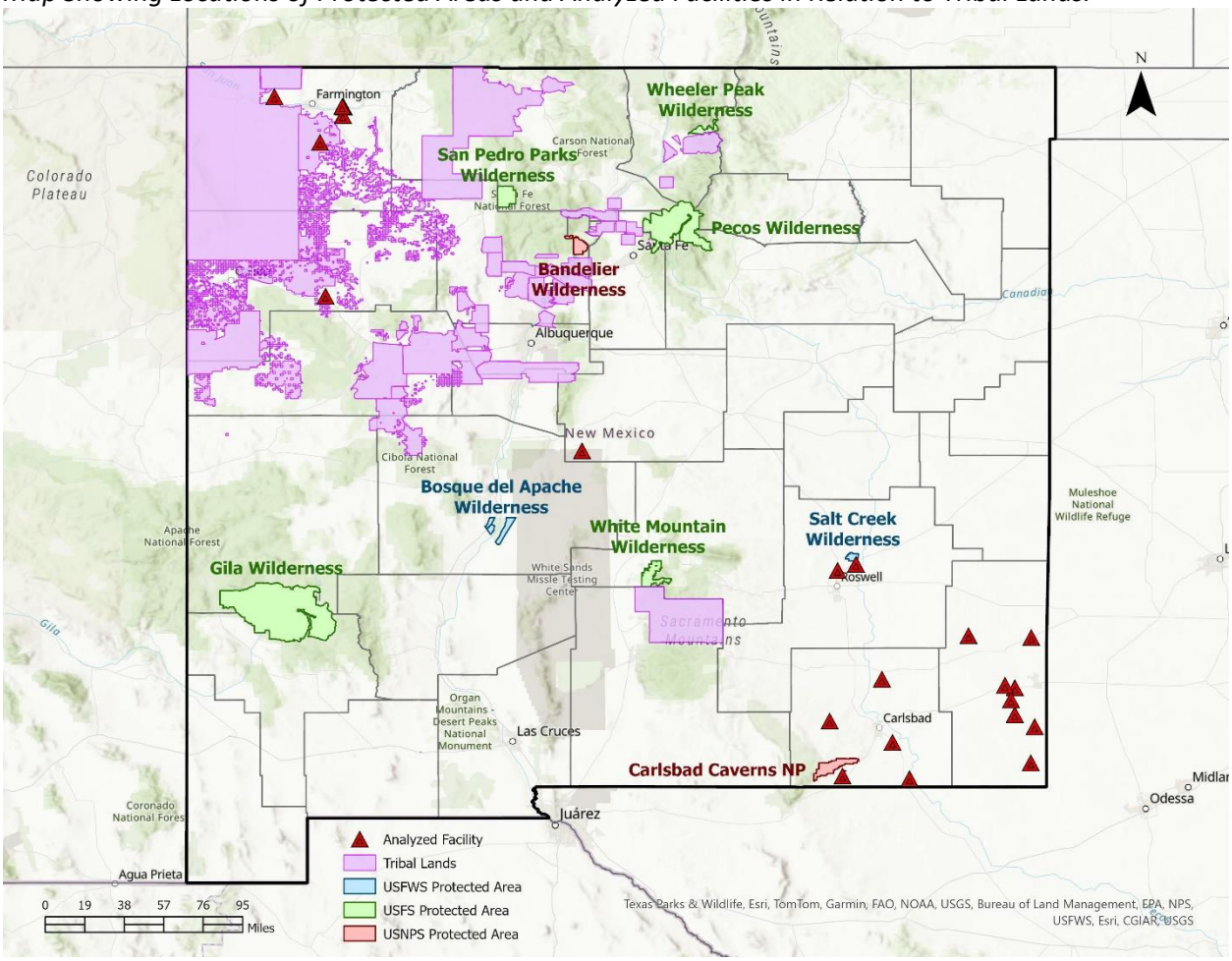
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Jearld Peabody, Director, Natural Resource Department, jerald.jpeabody@utemountain.org
Scott Clow, Director, Environmental Programs, sclow@utemountain.org
Janice Archuleta, Manager, Air Quality Program, jarchuleta@utemountain.org
Aryssia Sells, Air Quality Specialist, ASells@utemountain.org
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
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June 6, 2024

Pueblo of Ysleta del Sur
Governor E. Michael Silvas
117 S. Old Pueblo Road, P.O. Box 17579
El Paso, TX, 79907
tribalcouncil@ydsp-nsn.gov

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Silvas,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

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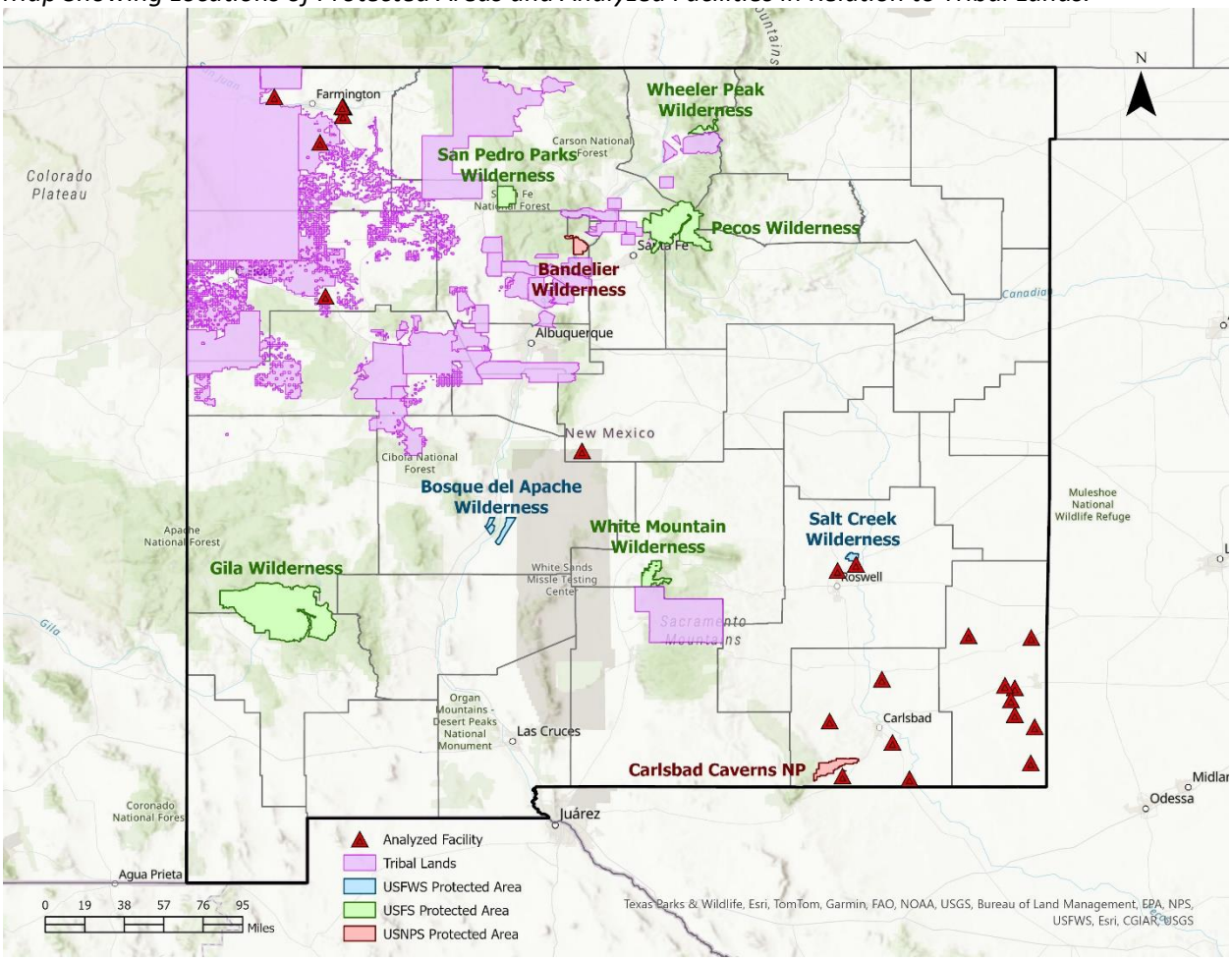
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Evaristo A. Cruz, Director, ecruz@ydsp-nsn.gov
Barbra Valdivieso, bvaldivieso@ydsp-nsn.gov
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
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June 6, 2024

Pueblo of Zia
Governor Ben Shije
135 Capitol Square Dr.
Zia Pueblo, NM, 87053
governor@ziapueblo.org

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Shije,

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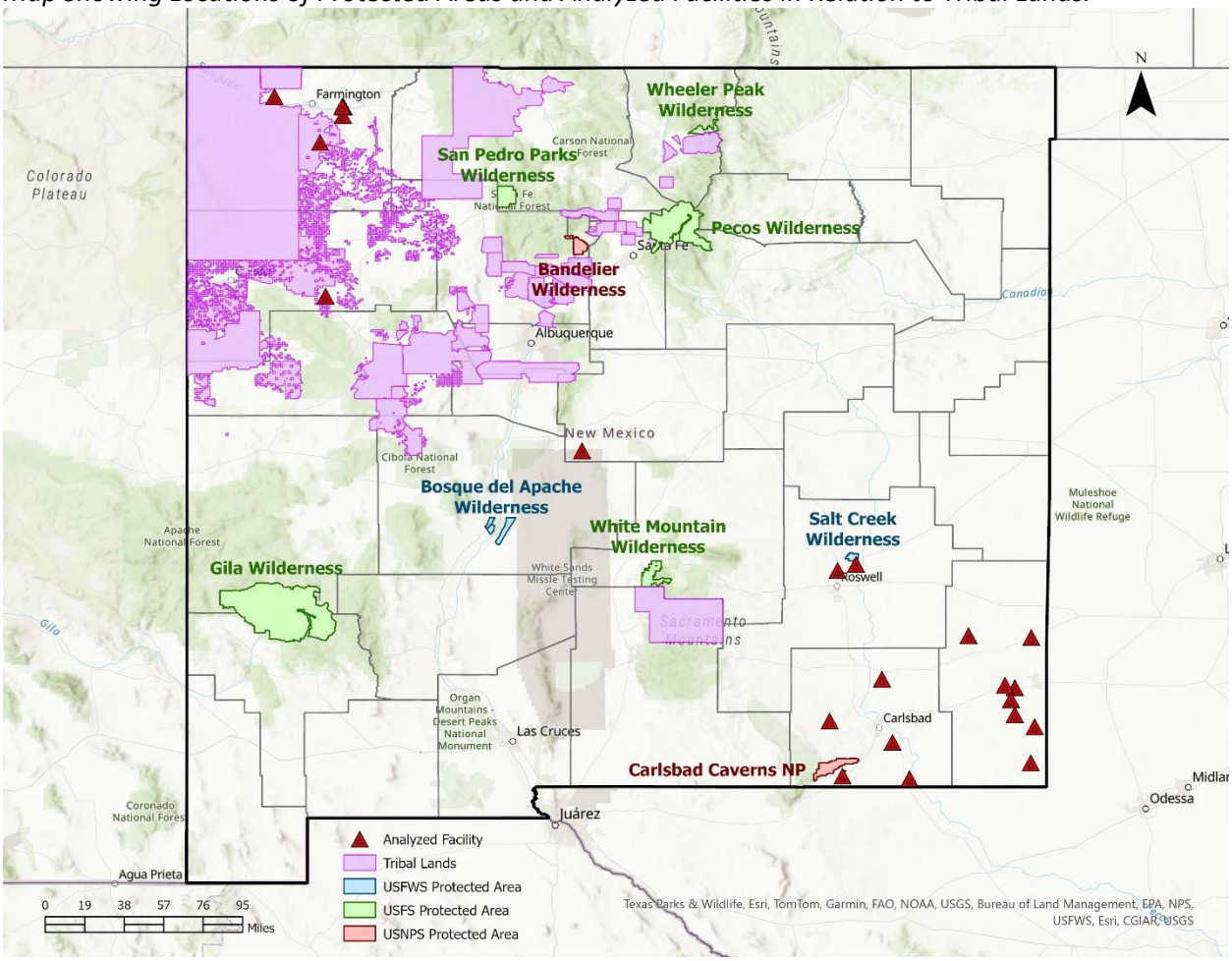
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Yvonne Benton, Director, ybenton@ziapueblo.org
Ken Lucero, Tribal Administrator, Ken.lucero@ziapueblo.org
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
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June 6, 2024

Pueblo of Zuni
Governor Arden Kucate
P.O. Box 339
Zuni, NM, 87327
arden.kucate@ashiwi.org

Re: Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan

Dear Honorable Governor Kucate,

The New Mexico Environment Department (NMED) writes to inform you of an opportunity to engage with our agency as we develop a plan, known as a State Implementation Plan, to reduce haze and improve visibility in certain National Parks and wilderness areas in New Mexico. The plan is aimed at fulfilling certain requirements of the federal Clean Air Act, which states must meet pursuant to the federal regulation known as the Regional Haze Rule.[1] The areas the Rule protects include Bandelier Wilderness Area; Bosque del Apache Wilderness Area; Carlsbad Caverns National Park; Gila Wilderness Area; Pecos Wilderness Area; Salt Creek Wilderness Area; San Pedro Parks Wilderness Area; Wheeler Peak Wilderness Area; and White Mountain Wilderness Area.

In developing this plan, NMED first reviewed visibility data from monitor sites located near each protected area. The data show overall improvement in visibility conditions at all areas over the past 20 years. To ensure this trend continues, NMED evaluated potential control measures to reduce emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_X), which contribute to the formation of visibility-impairing pollutants, at 23 large industrial facilities around the State. The facilities selected for analysis were predominantly oil and gas facilities located in the southeastern and northwestern portions of the State. A map showing the locations of these facilities in relation to protected areas is attached to this letter for reference. Through this analysis, which was primarily based on the cost of available controls but also considered other factors, NMED determined that 44 individual emissions units at 13 separate facilities require new pollution controls. Once implemented, these controls will result in significant reductions of NO_X and SO_2 emissions annually, which in concert with other measures will help to improve visibility not just at protected areas, but throughout the State.

We are expressly seeking feedback and comments from Tribal governments in New Mexico on our plan, as it may impact Tribal Lands. A draft plan is available to you for review and comments here: https://service.web.env.nm.gov/urls/VycLCxYU. Please note, this draft is not for public distribution, and is meant for only review by representatives of Tribal government. We would also be happy to email you a copy directly or mail you a printed copy if that would be more convenient. We are also planning on holding an informational webinar for Tribal government representatives to provide an overview of the plan and answer any questions you may have if that would be of interest on June 18, 2024 from 10:30am until 12:00pm, MDT. The meeting details and link will be sent in an email closer to this date. If you are planning on attending the webinar, please contact Mark Jones at the phone number or email address provided below to inform us of your intention. We respectfully request that you provide any

[1] 40 CFR §§ 51.300-51.309.

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comments on the draft plan directly to Mark Jones by July 19, 2024. After this date, NMED will consider any comments which we have received before proceeding with public outreach.

Additional opportunities for public engagement are in the works for later this summer including, at a minimum, a formal 30-day public comment period during which Tribes, Nations, and Pueblos in New Mexico will have a second opportunity to provide comment on our plan. Once the public notice dates have been determined, they will be posted at https://www.env.nm.gov/public-notices/. Any information and dates pertaining future webinars, along with additional opportunities to participate in our decision-making processes, will also be available at this website.

For more information, a website dedicated to Regional Haze planning in New Mexico is available at the following link: https://www.env.nm.gov/air-quality/reg-haze/. This website describes Environmental Protection Agency (EPA) requirements, shows visibility trends at New Mexico's protected areas, and provides additional information on NMED's planning process and guiding principles. If you or someone in your government is interested in participating in or following the Regional Haze planning process more closely, you may also sign up for email and/or text updates here: https://public.govdelivery.com/accounts/NMED/subscriber/new and subscribe to the Air Quality Bureau Regional Haze Announcements topic. This email alert system, in conjunction with the public notice board website described below, is the best way to stay current on events regarding Regional Haze as the project moves forward.

If you require another method of communication, please call or write our main office or Tribal Liaison and request your preferred method of communication with your contact information. We will make every effort to accommodate your preferences. You may contact our main office or Tribal Liaison using the information provided below.

For additional information concerning this letter, please contact:

Mark Jones: (505) 629-6626, mark.jones@env.nm.gov

Sincerely,

DocuSigned by:
Danielle L Gallegos
BD8C44EB00D548E...

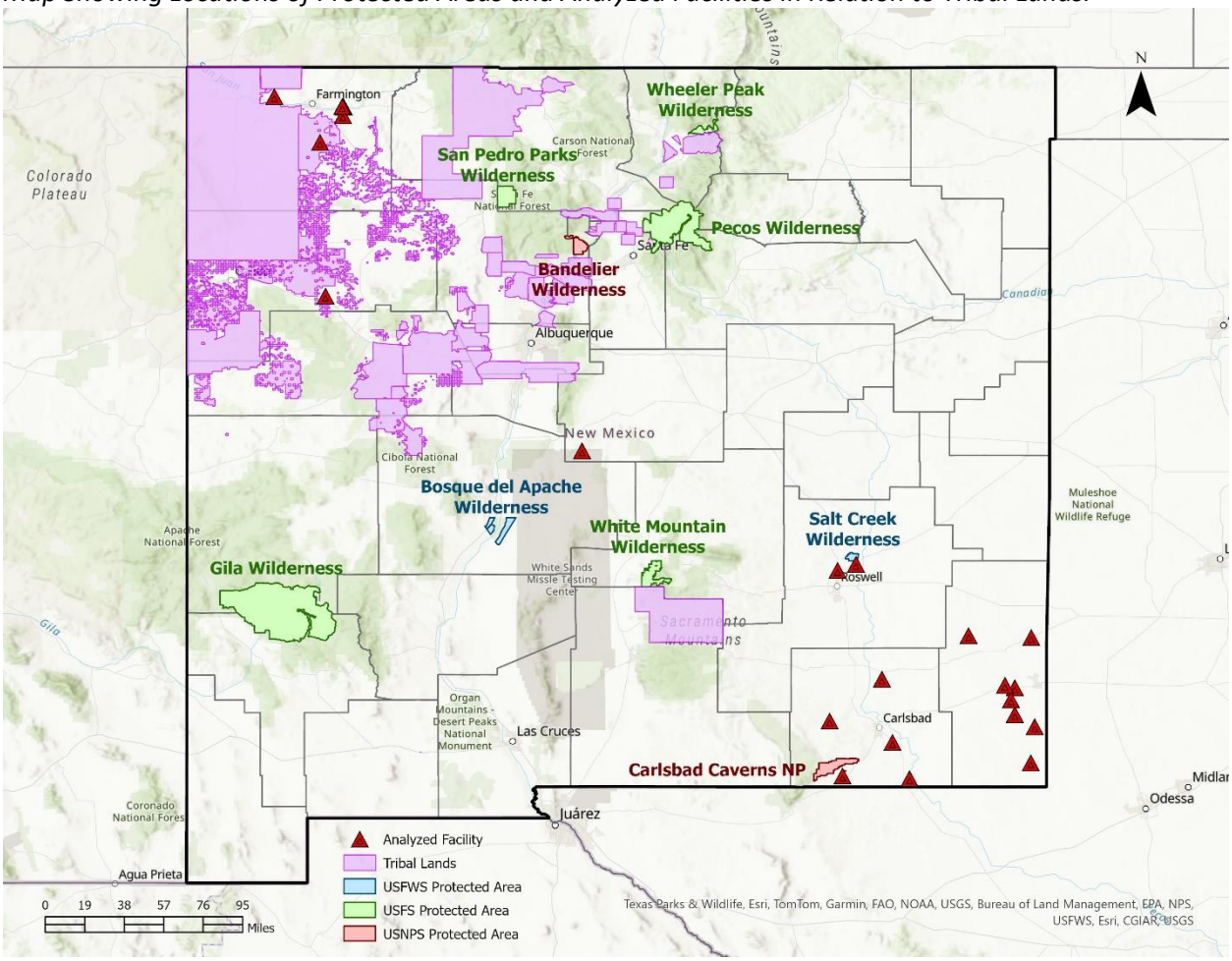
For
James Kenney
Cabinet Secretary
New Mexico Environment Department

Cc: Tammy Parker, Director, tammy.parker@ashiwi.org
Michelle Miano, Environmental Protection Division Director, michelle.miano@env.nm.gov
Dana Bahar, Acting Air Quality Bureau Chief, dana.bahar@env.nm.gov
Eric Peters, Control Strategies Manager, eric.peters@env.nm.gov
Kathryn S. Becker, Tribal Liaison, kathryn.becker@env.nm.gov

Enclosures: Map Showing Locations of Protected Areas and Analyzed Facilities in Relation to Tribal Lands

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Map Showing Locations of Protected Areas and Analyzed Facilities in Relation to Tribal Lands.



New Mexico Environment Department



Overview of Draft Regional Haze Plan for Tribes, Nations, and Pueblos

NMED Regional Haze Planning Team
June 18, 2024

Agenda

- Introductions
- Background
- Impact on Tribes
- Overview of Draft Plan
  - Selected Sources
  - Control Evaluations
  - Results of Analysis
- Navigating the Draft Plan
- Engagement Opportunities
- Discussion

NMED Regional Haze Planning Team

Project Staff:

- Eric Peters, Control Strategies Manager
  - 505-629-5299; eric.peters@env.nm.gov
- Mark Jones, Planner
  - 505-629-6626; mark.jones@env.nm.gov
- Ken Miller, Planner
  - 505-629-8673; kenneth.miller@env.nm.gov
- Alex Sanchez, Planner
  - 505-629-7891; alex.sanchez@env.nm.gov

NMED Regional Haze Planning Website:

https://www.env.nm.gov/air-quality/reg-haze/

Background

- The Regional Haze Rule calls for state and federal agencies to work together to improve visibility in 156 national parks and wilderness areas across the United States; these protected areas are known as “Mandatory Class I Areas”
- States are required to develop plans to reduce the pollution that causes visibility impairment in protected areas; these plans must be revised every 10 years
- States coordinate and consult with EPA, other states, Tribal governments, the general public, and others when developing their Regional Haze plans

Background


Mandatory Class I Areas
North Cascades
Pasayten
Olympic
Glacier Peak
Cabinet Mountains
Glacier
Alpine Lakes
Mount Rainier
Goat Rocks
Mount Adams
Mission Mountains
Bob Marshall
Medicine Lake
Lostwood
Scapegoat
UL Bend
Mount Hood
Hells Canyon
Gates of the Mountains
Theodore Roosevelt
Mount Jefferson
Eagle Cap
Anaconda Pintler
Mount Washington
Three Sisters
Selway-Bitterroot
Diamond Peak
Strawberry Mountain
Yellowstone
Crater Lake
Red Rock Lakes
North Absaroka
Kalmiopsis
Mountain Lakes
Sawtooth
Grand Teton
Washakie
Marble Mountain
Gearhart Mountain
Redwood
Lava Beds
Craters of the Moon
Teton
Fitzpatrick
Wind Cave
Badlands
South Warner
Bridger
Thousand Lakes
Jarbidge
Caribou
Lassen Volcanic
Yolla Bolly-Middle Eel
Point Reyes
Desolation
Mokelumne
Mount Zirkel
Rawah
Rocky Mountain
Flat Tops
Emigrant
Hoover
Yosemite
Ansel Adams
Capitol Reef
Arches
Eagles Nest
Maroon Bells - Snowmass
Pinnacles
Kaiser
John Muir
Bryce Canyon
West Elk
Black Canyon
Ventana
Sequoia / Kings Canyon
Zion
Canyon-lands
La Garita
Great Sand Dunes
Domeland
Grand Canyon
Mesa Verde
Weminuche
San Rafael
Wheeler Peak
San Pedro Parks
San Gabriel
Cucamonga
Sycamore Canyon
Pecos
San Gorgonio
Bandelier
San Jacinto
Pine Mountain
Petrified Forest
Agua Tibia
Joshua Tree
Mazatzal
Sierra Ancha
Mount Baldy
Bosque del Apache
Wichita Mountains
Superstition
Salt Creek
Galiuro
Gila
White Mountain
Saguaro
Chiricahua
Carlsbad Caverns
Guadalupe Mountains
Big Bend
Denali
Bering Sea
Tuxedni
Simeonof
Haleakala
Hawaii Volcanoes
Virgin Islands
1/2007
Produced by NPS Air Resources Division
Voyageurs
Isle Royale
Boundary Waters Canoe Area
Rainbow Lake
Seney
Roosevelt Campobello
Moosehorn
Acadia
Great Gulf
Presidential Range-Dry River
Lye Brook
Brigantine Wilderness
Dolly Sods
Otter Creek
Shenandoah
James River Face
Mammoth Cave
Mingo
Hercules-Glades
Great Smoky Mtns
Linville Gorge
Swanquarter
Upper Buffalo
Joyce Kilmer-Slickrock
Shining Rock
Cohutta
Caney Creek
Sipsey Wilderness
Cape Romain
Wolf Island
Okefenokee
Bradwell Bay
Saint Marks
Breton
Chassahowitzka
Everglades
0 125 250 500
Kilometers
NPS Unit
USFS Unit
FWS Unit

Impact on Tribes

- Reduced visibility due to regional haze impacts more than just protected areas; it impacts visibility in the rest of New Mexico including Tribal lands
- Regional haze is a symptom of broader air quality problems that affect not just visibility, but health too, including the health of Tribal members
- Tribes can submit their own plans to address regional haze if they choose, but generally rely on state plans
- NMED is committed to coordinating with Tribes and values your feedback on its draft Regional Haze plan

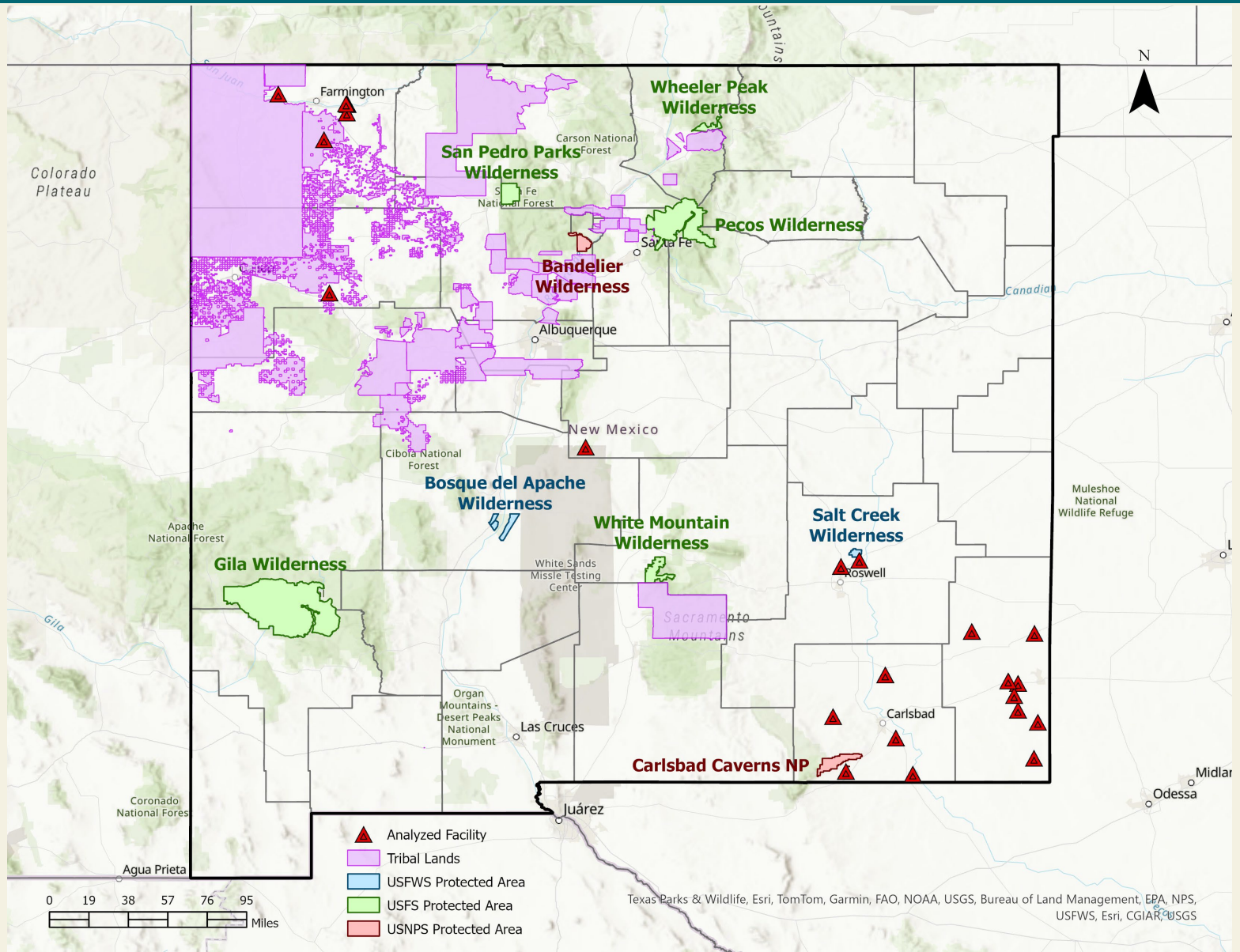
Overview of Draft Plan

SELECTED SOURCES

Selected Sources

- NMED used a screening process to select 23 facilities for an analysis of potential control measures
- NMED evaluated 133 individual emissions units at those facilities based on additional screening criteria
- The goal of NMED's screening process was to focus efforts on higher emitting units at the largest sources of air pollution that are most likely to affect visibility in protected areas based on their emissions and proximity to those areas

Selected Sources



Overview of Draft Plan

CONTROL EVALUATIONS

Control Evaluations

- Identify all feasible control options for each unit
- For each feasible option:
  - Determine cost to implement ($)
  - Estimate emissions reductions (tons/year)
  - Calculate cost effectiveness ($/ton)
- Determine appropriate cost threshold
- Select required controls

Control Evaluations

Case Example: Natural Gas Compressor Engine



Control Evaluations

- Annualized Cost of Control Options:
  - Low Emission Combustion = $837,000
  - Replacement = $1,213,000
  - Electrification = $1,361,000
- Estimated Emissions Reductions:
  - Low Emission Combustion = 118.3 tons/year
  - Replacement = 123.5 tons/year
  - Electrification = 131.2 tons/year
- Cost effectiveness:
  - Low Emission Combustion = $7,900/ton
  - Replacement = $11,600/ton
  - Electrification = $10,400/ton
- Required Control = Low Emission Combustion

Overview of Draft Plan

RESULTS OF ANALYSIS

Results of Analysis

- New Controls on 44 Emissions Units
- Permanent Retirement of 34 Emissions Units
- Measures to Ensure Continued Use of In-Place Controls on 11 Emissions Units
- Significant Reductions in Emissions of Pollutants that Contribute to Visibility Impairment
  - Nitrogen Oxides > 16,000 tons/year
  - Sulfur Dioxide > 5,000 tons/year

Navigating Draft Plan

- Table of Contents
  - Headings, Figures, and Tables are all Hyperlinked
- Embedded Bookmarks
  - View > Show/Hide > Navigation Panes > Bookmarks
- Other Review Aids
  - List of Abbreviations
  - Executive Summary

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Engagement Opportunities

- Informal Comment Period
  - Limited to Tribes and Government Agencies
  - Ends July 19, 2024
- Formal 30-Day Public Comment Period
  - Anyone Can Comment, Including Tribes
  - Dates TBD; Anticipate Late Summer/Early Fall
  - https://www.env.nm.gov/public-notices/
- Public Hearing
  - Anyone Can Give Public Comment or Testimony
  - Dates TBD; Anticipate Late Fall

Discussion

QUESTIONS?

Ute Mountain Ute Tribe

Environmental Programs Department
P.O. Box 448
Towaoc, Colorado 81334-0448

(970) 564-5430

July 19, 2024

Mark Jones
NMED
Mark Jones | Environmental Analyst
Regional Haze Team - Technical Lead
NMED Air Quality Bureau
mark.jones@env.nm.gov
(505) 629-6626

RE: **Tribal Feedback on State of New Mexico's Draft Regional Haze State Implementation Plan-Second Planning Period**

Dear Mr. Jones,

The Ute Mountain Ute Tribe (UMUT) Environmental Programs Department (EPD) appreciates that the New Mexico Environment Department sent consultation correspondence to the Ute Mountain Ute Tribe's Leaders for feedback on the New Mexico's Draft Regional Haze State Implementation Plan-Second Planning Period (Plan). The EPD is pleased to submit these comments on the Plan.

The Ute Mountain Ute Indian Reservation is located in extreme southwestern Colorado, southeastern Utah and northwestern New Mexico. The Reservation is approximately 933 square miles in total area of trust land which is homeland for the population of 2,100 members. Presently, there are several pollution sources in the area and in the region of Tribal Reservation Lands that have decreased the visibility in and around the Tribal Lands and the Ute Mountain Ute Tribe has concerns that pollutants are also acting to compound adversely to the health of the tribe's environment and population, and that of the region as well. Tribal landmarks are crucial to the members and community and we support the efforts of New Mexico Environmental Department to take measures to reduce visual pollution.

In general, the EPD supports the Plan that fulfills the goals of the EPA's rulemaking for an increase in visibility as a result for the near-term and long-term targets through reductions in emissions. Several of these emission reductions will also be advantageous to the UMUT reservation lands because they are with a 50 mile radius of the sources.

The comments regarding the draft NMED SIP for RHR Second Planning Period are in the attached file, *JA review NM Draft SIP June 2024.* We understand that the plan has been defined though the regulatory framework of the EPA. Comments include:

- not being in agreement with the conclusions drawn in parts of Section 5 detailed in the attached review file, and a few editorial mistakes,
- references for the data are provided, however, a thumbnail sketch of the dataset origination in the sections where they are used (Section 5) would have been immensely helpful for evaluation of this review or understanding in general.
- The EPD is specifically supportive of:
  - The Renewable Energy Goals in Section 5.4.7, which states the reduction in pollutant emissions from sources were reduced dramatically with the expansion of renewable energy goals; electricity generation by renewable resources surpassed coal production for the first time in 2022,
  - the regulatory methods in section 8.2 - these regulated emission limitations and compliance deadlines should be an effective and enforceable method for emissions reductions at the identified facilities.
  - the currently adopted regulations in Section 8.3.1, the Ozone Precursor Pollutants-Oil and Gas Sector Rule and the New Motor Vehicle Emission Standards Rule would further reduce emissions that cause visibility impairment.

The EPD would like to acknowledge appreciation to New Mexico (Environment Department) that New Mexico, who is also a member of the Western Regional Air Partnership (WRAP) aligned with the WRAP's Communications Framework for Regional Haze Planning, adopted by consensus, Sept. 3, 2019[i]. This document calls out that Tribes should be engaged and consulted in the state's RHR Planning process, especially those Tribes that are members, such as the Ute Mountain Ute Tribe. Unfortunately, not all of the WRAP partners followed this process in their planning.

One correction to Tribal contacts should be noted, Jerald Peabody, Director, Natural Resource Department, jerald.jpeabody@utemountain.org has been replaced by David Stoner, dstoner@utemountain.org.

If there are any questions or concerns relating to these comments, please feel free to contact Scott Clow, Environmental Programs Director, at 970-564-5432, or the Air Quality Program Manager, Janice Archuleta at 970-564-5433.

On Behalf of the Ute Mountain Ute Tribe Environmental Programs Department,

Respectfully Submitted,

Janice Archuleta

Cc:

Manual Heart, Chairman. Ute Mountain Ute Tribe, Manuel.Heart@utemountain.org
Selwyn Whiteskunk, Vice-Chairman, Ute Mountain Ute Tribe,
Selwyn.Whiteskunk@utemountain.org
Darwin Whiteman Jr., Treasurer, Ute Mountain Ute Tribe
Alston Turtle, Secretary, Ute Mountain Ute Tribe
Conrad Jacket, Council Representative
Malcolm Lehi, White Mesa Council Representative
Peter Ortego, General Counsel
Scott Clow, Director, Environmental Programs, sclow@utemountain.org

Ute Mountain Ute Comments on draft SIP narrative (7/19/24)

In reference to "Such consideration was not necessary because the First Period SIP did in fact demonstrate a projected continuous decline in mobile source emissions for the period 2003 to 2008:" Comment: This statement relies on Section 5.4.4 data which does not represent this statement. Somewhere in the mobile sources section in section 5. there could be a discussion about how to further reductions in emissions will be implemented with the planned regulatory actions mentioned in 8.3.1, those which would have an effect on mobile sources.
In reference to Section 5.4.4, "This Section presents data from WRAP consistent with a decline in mobile source emissions over the period 2003-2018." Comment: Table 5-3 does not support this statement. At the very least, it can be reported that 2 of the 4 pollutant categories have declined from 2002 to 2011.
In reference to Table 5-3 "Coarse Mass (Particulate Matter) (TPY). Comment: Coarse Mass increased from 2002, in 2008 and 2011.
In reference to Table 5-3 "Primary Organic Aerosols (TPY)." Comment: Primary Organics Aerosols increased from 2002, in 2008 and 2011.
In reference to Table 5-4. Comment: The totals for the PM10 are 48 TPY, and the totals for the PM2.5 are are 43 TPY. Taking into consideration the statistical errors embedded in the dataset or model, this amount of variation could be insignificant, i.e., the TPY's for 2014 and 2018 'are equal'. This would invalidate the statements above.
In reference to Section 5.4.7. Comment: Alternative energy to fossil fuels proves to reduce emissions. The UMUT has plans for new renewable projects as well.
In reference to Section 5.7.13- "The data shown in Section 5.4.5- Mobile Sources, confirmed this overall decline. Two comments. 1: The data presented in 5.4.4 did not confirm this statement. Only 2 of the pollutant categories supported this statement." 2: "4, See Section 5.4.4."
In reference to Section 5.7.4.1. "In Section 5.4.7, this is not true for NOx and may not be supported by the SOx TPY either."
In reference to the statement "Furthermore, increasing the CETV to $14,000/ton would result in just a few hundred additional tons per year of NOx reductions at considerable additional cost to the affected sources." Comment: This could be presented here and have the reader make this decision instead of speaking generally.
In reference to Section 8.2.1. Comment: The regulatory emission limitations and compliance deadlines are an effective and enforceable method for emissions reductions at the identified facilities.
In reference to the 2024-04-29 Ameredev Settlement under Section 10.3.4.2. Comment: Is a description of the outcome missing here?
In reference to Chapter 11, under Figure 11-1. Comment: The WRAP's Communications Framework for Regional Haze Planning, Sept. 3, 2019, could/should be mentioned somewhere in the document.

E.5 Discussions with Industry

Supporting documentation for NMED coordination with Industry is provided below. The following documents are included in this section (in reading order):

- NMED Communications
    - Notifications to Companies that Their Facility is Subject to Regional Haze Four-Factor Analysis and Control Measure Determinations (7/18/19)
    - Notice to Industry of Draft Final Cost Control Evaluation Availability for Review (12/14/2023)
    - Advance Notice to Industry of available NMED draft Regional Haze SIP revision and Companion Rule (8/19/24)

[1] Additional Supporting Documentation on Industry Communications on Four Factor Analysis is Provided in Appendix D.

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Michelle Lujan Grisham
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Howie C. Morales
Lt. Governor

James C. Kenney
Cabinet Secretary

Jennifer J. Pruett
Deputy Secretary

July 18, 2019

Mr. Andy Berger
Tri-State Generation and Transmission Association
PO Box 33695
Denver CO, 80233

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Mr. Berger:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Escalante Generating Station in Prewitt, New Mexico as a facility subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified twenty-four (24) Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or

about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

xc: Daniel Salgado, Tri-State Generation and Transmission Association

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

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July 18, 2019

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PO Box 4324
Houston, TX 77210-4324

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Ms. Miro:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Enterprise – South Carlsbad Compressor Station in Eddy County, New Mexico as a facility subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified twenty-four (24) Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or

about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 476-4350.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

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Lt. Governor

James C. Kenney
Cabinet Secretary

Jennifer J. Pruett
Deputy Secretary

July 18, 2019

Ms. Carolyn Blackaller
ETC Texas Pipeline, Ltd.
600 North Marien Feld Street, Suite 700
Midland, TX 79701

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Ms. Blackaller:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Jal No. 3 Gas Plant near Jal, New Mexico as a facility subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified twenty-four (24) Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or

about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

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Cabinet Secretary

Jennifer J. Pruett
Deputy Secretary

July 18, 2019

Ms. Cynthia Klein
Targa Midstream Services
14000 Quail Springs Parkway, Suite. 215
Oklahoma City, OK 73134

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Ms. Klein:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Monument Gas Plant, Eunice Gas Processing Plant and Saunders Gas Plant in Lea County, New Mexico as facilities subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified 24 Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or

about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

xc: Rebecca Woodell, Targa Midstream Services

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

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Deputy Secretary

July 18, 2019

Ms. Elena Hofmann
Davis Gas Processing
13201 NW Freeway, Suite 200
Houston, TX 77040

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Ms. Hofmann:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Denton Gas Plant in Lea County, New Mexico as a facility subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified twenty-four (24) Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or

about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
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Deputy Secretary

July 18, 2019

Mr. Kijun Hong
Harvest Four Corners, LLC
1755 Arroyo Drive
Bloomfield, NM 87413

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Mr. Hong:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Kutz Canyon Processing Plant and Harvest Pipeline – San Juan Gas Plant facilities in San Juan County, New Mexico as facilities subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified twenty-four (24) Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership ("WRAP"), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

Because the Harvest Pipeline - San Juan Gas Plant is jointly permitted with the El Paso Natural Gas – Blanco Compressor Station A and the Enterprise Field Services, LLC – Blanco C&D Compressor Station under NSR Permit No. 0613-M12, NMED requests a combined four-factor analysis for these three facilities. The four-factor analysis for the Kutz Canyon Processing Plant should be submitted as a separate report. NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

xc: Monica Sandoval, Harvest Midstream, LLC

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Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

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Lt. Governor

James C. Kenney
Cabinet Secretary

Jennifer J. Pruett
Deputy Secretary

July 18, 2019

Mr. Larry Campbell
Transwestern Pipeline
6381 Main Street
Roswell, NM 88201

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Mr. Campbell:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Roswell Compressor Station No. 9 and the Mountainair No. 7 Compressor Station in Chaves and Torrance counties, respectively, as facilities subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified twenty-four (24) Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

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Deputy Secretary

July 18, 2019

Mr. Tony Hines
IACX Roswell, LLC
5001 LBJ Freeway, Suite 300
Dallas TX, 75244

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Mr. Hines:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Bitter Lake Compressor Station located northeast of Roswell, New Mexico as a facility subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified twenty-four (24) Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or

about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

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Deputy Secretary

July 18, 2019

Mr. Travis Ray
El Paso Natural Gas Company
8645 Railroad Drive
El Paso, TX 79904

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Mr. Ray:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Blanco Compressor Station A in San Juan County, New Mexico as a facility subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified twenty-four (24) Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

Because the Blanco Compressor Station is jointly permitted with the Harvest Pipeline - San Juan Gas Plant and the Enterprise Field Services, LLC – Blanco C&D Compressor Station under NSR Permit No. 0613-M12, NMED requests a combined four-factor analysis for these three facilities. NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

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Deputy Secretary

July 18, 2019

Ms. Zainab Naqvi
El Paso Natural Gas Company
8645 Railroad Drive
El Paso, TX 79904

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Ms. Naqvi:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Washington Ranch Storage Facility and the Pecos River Compressor Station in Eddy County, New Mexico as facilities subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified 24 Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or

about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

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Jennifer J. Pruett
Deputy Secretary

July 18, 2019

Mr. Trevor Baird
DCP Midstream
10 Desta Drive, Suite 500 West
Midland, TX 79705

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Mr. Baird:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the DCP – Linam Ranch Gas Plant facility in Lea County, New Mexico as a facility subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified twenty-four (24) Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

xc: Jennifer Hanna, DCP Midstream

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

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Governor

Howie C. Morales
Lt. Governor

James C. Kenney
Cabinet Secretary

Jennifer J. Pruett
Deputy Secretary

July 18, 2019

Mr. Nicholas Case
DCP Operating Company
10 Desta Drive, Suite 400 West
Midland, TX 79705

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Mr. Case:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Artesia Gas Plant in Eddy County, New Mexico as a facility subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified twenty-four (24) Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or

about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
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Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

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Jennifer J. Pruett
Deputy Secretary

July 18, 2019

Mr. Bill Glushko
DCP Operating Company, LP
10 Desta Drive, Suite 500 West
Midland, TX 79705

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Mr. Glushko:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Eunice Gas Plant northwest of Eunice, New Mexico as a facility subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified twenty-four (24) Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or

about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

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Cabinet Secretary

Jennifer J. Pruett
Deputy Secretary

July 18, 2019

Mr. James Lieb
Enterprise Field Services
PO Box 4324
Houston, TX 77210-4324

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Mr. Lieb:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Chaco Gas Plant and the Blanco C&D Compressor Station located in San Juan County, New Mexico as facilities subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified twenty-four (24) Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

Because the Blanco C&D Compressor Station is jointly permitted with the Harvest Pipeline - San Juan Gas Plant and the El Paso Natural Gas Company – Blanco Compressor Station A under NSR Permit No.

0613-M12, NMED requests a combined four-factor analysis for these three facilities. The four-factor analysis for the Chaco Gas Plant should be submitted as a separate report. NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
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Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
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Jennifer J. Pruett
Deputy Secretary

July 18, 2019

Ms. Femi Serrano
Oxy USA
5 Greenway Plaza, Suite 110
Houston, TX 77046-0521

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Ms. Serrano:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Oxy – Indian Gas Plant facility in Eddy County, New Mexico as a facility subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified twenty-four (24) Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

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Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

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NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

xc: Dennis Newman, Oxy USA

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Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
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Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
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South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
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*Located in Bernalillo County outside of NMED Jurisdiction.

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Deputy Secretary

July 18, 2019

Ms. Maureen Gannon
Public Service Company of New Mexico
2401 Aztec Road NE, MS Z100
Albuquerque, NM 87107

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Ms. Gannon:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the San Juan Generating Station in Waterflow, New Mexico as a facility subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified 24 Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

NEW MEXICO
ENVIRONMENT DEPARTMENT

525 Camino de los Marquez, Suite 1
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www.env.nm.gov

Michelle Lujan Grisham
Governor

Howie C. Morales
Lt. Governor

James C. Kenney
Cabinet Secretary

Jennifer J. Pruett
Deputy Secretary

July 18, 2019

Mr. Kevin L. Worley
Xcel Energy
PO Box 1261
Amarillo, TX 79105

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Mr. Worley:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Xcel Energy – Cunningham Station facility in Lea County, New Mexico as a facility subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified twenty-four (24) Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

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Cabinet Secretary

Jennifer J. Pruett
Deputy Secretary

July 18, 2019

Mr. James Lieb
Enterprise Field Services
PO Box 4324
Houston, TX 77210-4324

Subject: Notification of Requirement to Perform a Four-Factor Analysis on Control Measures Under the Clean Air Act Regional Haze Program

Dear Mr. Lieb:

This letter is to inform you that the New Mexico Environment Department (NMED) has identified the Chaco Gas Plant and the Blanco C&D Compressor Station located in San Juan County, New Mexico as facilities subject to a four-factor reasonable progress analysis under the federal Clean Air Act, 42 U.S.C. § 7491, and implementing regulations at 40 CFR §§ 51.300 to 51.309 (Regional Haze Rule).

The NMED has identified twenty-four (24) Title V permitted facilities across the state that may potentially have an impact on visibility at Federal Class 1 Areas protected by the Regional Haze Rule. This determination was based on a methodology developed by the Western Regional Air Partnership (WRAP), consistent with guidance from the U.S. Environmental Protection Agency (EPA).

The four-factor analysis is necessary for NMED to develop a long-term strategy to address regional haze visibility impairment. The four-factor analysis considers emission reduction measures based on (1) the cost of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of an existing source subject to this requirement. We request that you analyze all the identified control measures in terms of the four factors specified in 40 CFR § 308(f)(2)(i), consistent with relevant EPA guidance.

Therefore, in accordance with the Regional Haze Rule, NMED requests that your company perform a four-factor analysis of all potential new control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) on individual equipment that has the potential to emit (PTE) greater than ten (10) pounds per hour of NO_X or SO_2. A separate analysis is required for each pollutant with a PTE greater than ten (10) pounds per hour of NO_X or SO_2. Note that equipment exempt under 20.2.72 NMAC or insignificant under 20.2.70 NMAC is not required to undergo the analysis. Likewise, individual equipment of the same source category is not required to be aggregated in order to determine if an analysis is required. Individual emission points that total less than five (5) tons per year for either pollutant do not need to undergo this analysis.

Because the Blanco C&D Compressor Station is jointly permitted with the Harvest Pipeline - San Juan Gas Plant and the El Paso Natural Gas Company – Blanco Compressor Station A under NSR Permit No.

0613-M12, NMED requests a combined four-factor analysis for these three facilities. The four-factor analysis for the Chaco Gas Plant should be submitted as a separate report. NMED respectfully requests that your company submit a report containing the complete four-factor analysis no later than November 1, 2019. Prior to that date, NMED plans to hold a teleconference on or about September 4th to review progress in identifying technically feasible control measures and conducting the four-factor analysis for each subject source.

Following submission of the facility's report, NMED will determine whether any of the identified control measures are cost effective and technically feasible for the facility in terms of the four-factor analysis. Any measures that are cost effective and technically feasible will be submitted to WRAP along with data quantifying the projected emission reductions that will result by calendar year 2028 from implementation of these measures. The modeling results will determine if projected emissions reductions will result in visibility improvement to the affected Class 1 area. If visibility improvements are not predicted by the model, the control measures will not be recommended.

NMED will incorporate the identified cost-effective measures into a proposed Regional Haze State Implementation Plan, which NMED will bring to the Environmental Improvement Board (Board). NMED will petition the Board for a rulemaking hearing on the proposed SIP in the first half of calendar year 2021, in order to meet the federal regulatory deadline of July 31, 2021 for submittal to the EPA.

Please contact NMED if you have questions about the methodology for conducting a four-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical analysis required under the Rule. Staff would be happy to meet with you in person to discuss these requirements in more detail. NMED has developed a website for Regional Haze with important links to EPA's Cost Control Manual and other technical information that may assist in these efforts.

Thank you for your assistance in this matter. If you have questions or need clarification, please contact Kerwin Singleton of my staff at (505) 476-4350, or Mark Jones at (505) 566-9746.

Sincerely,

Liz Bisbey-Kuehn
Chief, Air Quality Bureau

Attachments: 1) WRAP Control Measures Analysis Protocol
2) List of New Mexico Title V facilities identified as having potential visibility impacts at Federal Class 1 Areas

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

From:	Olson, Kirby, ENV
To:	jwcook@dcpmidstream.com
Cc:	John.W.Cook2@p66.com; steve.torpey@p66.com; elena.hofmann@eosolutions.net; Jones, Mark, ENV; Miller, Kenneth, ENV; Sanchez, Alex, ENV
Subject:	Draft Final Control Cost Evaluation for DCP Operating Company"s Linam Ranch Gas Plant
Date:	Thursday, December 14, 2023 5:12:13 PM
Attachments:	2023-12-14_Draft Final NMED Cost Evaluation_DCP - Linam Ranch Gas Plant.xlsx

Dear Mr. Cook,

Please find NMED's draft final control cost evaluation for the Regional Haze Second Planning Period for DCP Operating Company's Linam Ranch Gas Plant in the Excel workbook attached to this email.

We are providing this draft final evaluation as a courtesy so you can review it before NMED completes its draft SIP and begins the formal Federal Land Manager (FLM) consultation period required by EPA's Regional Haze Rule. Please review the sheets in the attached workbook for any errors or omissions in incorporating information that your company has previously submitted to NMED. Also, please use this opportunity to notify us of any previously undisclosed changes at your facility that could affect our pending control determinations, such as the decommissioning or replacement of units subject to Regional Haze, the addition of new pollution controls, or facility shutdowns. We reiterate that we are interested in any errors or omissions that you see as well as significant operational changes. For cases involving modifying or decommissioning units, relevant information would include how these are permitted to satisfy EPA's requirement that they be permanent and federally enforceable. Because NMED provided an opportunity to update cost information in summer and early fall 2023, we are no longer accepting updates to cost estimates. **The deadline to submit review comments by email to NMED is Jan 15, 2024**. We may not have time to review comments received after this deadline prior to completing our draft SIP.

As part of your review, please provide information on when units #8 and #9 will be removed through an administrative revision to the DCP – Linam Ranch Gas Plant Permit.

NMED has not yet completed its analysis of process flaring and SSM flaring emissions at DCP facilities. We will consider these emissions in a separate analysis covering multiple facilities unless we determine that a facility-specific analysis is required for any of DCP's facilities.

An updated overall timeline for the formal FLM review period and proposed hearing phase for New Mexico's Regional Haze State Implementation Plan for the second planning period will soon be available on our NMED Regional Haze planning website: https://www.env.nm.gov/air-quality/reg-haze/.

If you have any questions or feedback for our Regional Haze planning team, please contact me, Kirby Olson (Kirby.olson@env.nm.gov) and cc Mark Jones (mark.jones@env.nm.gov), Ken Miller (kenneth.miller@env.nm.gov) and Alex Sanchez (alex.sanchez@env.nm.gov).

Regards,

Kirby Olson

This email is intended to serve as general guidance and is in no way a formal statement of Department policy. Unique operating conditions may result in different determinations and may require a site specific analysis to accurately determine requirements and applicability.

Kirby Sue Olson, Ph.D.
Planning Section Chief
Air Quality Bureau
New Mexico Environment Department
525 Camino de los Marquez, Suite 1
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Phone: (505) 629-5107
Fax: (505) 476-4375
kirby.olson@env.nm.gov
https://www.env.nm.gov

"Science, Innovation, Collaboration, Compliance"

From:	Olson, Kirby, ENV
To:	Jacobson, Tucker
Cc:	Cooley, Bradley; Craft, Zachary; pkulkarnie@eprod.com; Jones, Mark, ENV; Miller, Kenneth, ENV; Sanchez, Alex, ENV
Subject:	Draft Final Control Cost Evaluations for Enterprise Field Services, LLC"s Facilities
Date:	Thursday, December 14, 2023 4:46:27 PM
Attachments:	2023-12-14_Draft Final NMED Cost Evaluation_Enterprise - Blanco C and D Compressor Station.xlsx 2023-12-14_Draft Final NMED Cost Evaluation_Enterprise - Chaco Gas Plant.xlsx 2023-12-14_Draft Final NMED Cost Evaluation_Enterprise - South Carlsbad Compressor Station.xlsx

Dear Mr. Jacobson,

Please find NMED's draft final control cost evaluations for the Regional Haze Second Planning Period for Enterprise Field Services, LLC's Blanco C & D Compressor Station, Chaco Gas Plant and South Carlsbad Compressor Station in the Excel workbooks attached to this email.

We are providing these draft final evaluations as a courtesy so you can review them before NMED completes its draft SIP and begins the formal Federal Land Manager (FLM) consultation period required by EPA's Regional Haze Rule. Please review the sheets in the attached workbooks for any errors or omissions in incorporating information that your company has previously submitted to NMED. Also, please use this opportunity to notify us of any previously undisclosed changes at your facilities that could affect our pending control determinations, such as the decommissioning or replacement of units subject to Regional Haze, the addition of new pollution controls, or facility shutdowns. We reiterate that we are interested in any errors or omissions that you see as well as significant operational changes. For cases involving modifying or decommissioning units, relevant information would include how these are permitted to satisfy EPA's requirement that they be permanent and federally enforceable. Because NMED provided an opportunity to update cost information in summer and early fall 2023, we are no longer accepting updates to cost estimates. **The deadline to submit review comments by email to NMED is Jan 15, 2024**. We may not have time to review comments received after this deadline prior to completing our draft SIP.

NMED has not yet completed its analysis of process flaring and SSM flaring emissions at Enterprise facilities. We will consider these emissions in a separate analysis covering multiple facilities unless we determine that a facility-specific analysis is required for any of Enterprise's facilities.

An updated overall timeline for the formal FLM review period and proposed hearing phase for New Mexico's Regional Haze State Implementation Plan for the second planning period will soon be available on our NMED Regional Haze planning website: https://www.env.nm.gov/air-quality/reg-haze/.

If you have any questions or feedback for our Regional Haze planning team, please contact me, Kirby Olson (Kirby.olson@env.nm.gov) and cc Mark Jones (mark.jones@env.nm.gov), Ken Miller (kenneth.miller@env.nm.gov) and Alex Sanchez (alex.sanchez@env.nm.gov).

Regards,

Kirby Olson

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Kirby Sue Olson, Ph.D.
Planning Section Chief
Air Quality Bureau
New Mexico Environment Department
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kirby.olson@env.nm.gov
https://www.env.nm.gov

"Science, Innovation, Collaboration, Compliance"

From:	Olson, Kirby, ENV
To:	Mitchell, Tom
Cc:	Ricardo_Duarte@KinderMorgan.com; Daly, Weiwen; Jones, Mark, ENV; Miller, Kenneth, ENV; Sanchez, Alex, ENV
Subject:	Draft Final Control Cost Evaluations for El Paso Natural Gas Company, LLC"s Facilities
Date:	Friday, December 15, 2023 2:25:40 PM
Attachments:	2023-12-15_Draft Final NMED Cost Evaluation_EPNG - Washington Ranch Storage Facility.xlsx 2023-12-15_Draft Final NMED Cost Evaluation_EPNG - Pecos River Compressor Station.xlsx 2023-12-15_Draft Final NMED Cost Evaluation_EPNG - Blanco Compressor Station A.xlsx

Dear Mr. Mitchell,

Please find NMED's draft final control cost evaluations for the Regional Haze Second Planning Period for El Paso Natural Gas Company, LLC's Blanco Compressor Station A, Pecos River Compressor Station and Washington Ranch Storage Facility in the Excel workbooks attached to this email.

We are providing these draft final evaluations as a courtesy so you can review them before NMED completes its draft SIP and begins the formal Federal Land Manager (FLM) consultation period required by EPA's Regional Haze Rule. Please review the sheets in the attached workbooks for any errors or omissions in incorporating information that your company has previously submitted to NMED. Also, please use this opportunity to notify us of any previously undisclosed changes at your facilities that could affect our pending control determinations, such as the decommissioning or replacement of units subject to Regional Haze, the addition of new pollution controls, or facility shutdowns. We reiterate that we are interested in any errors or omissions that you see as well as significant operational changes. For cases involving modifying or decommissioning units, relevant information would include how these are permitted to satisfy EPA's requirement that they be permanent and federally enforceable. Because NMED provided an opportunity to update cost information in summer and early fall 2023, we are no longer accepting updates to cost estimates. **The deadline to submit review comments by email to NMED is Jan 15, 2024**. We may not have time to review comments received after this deadline prior to completing our draft SIP.

Our NMED Regional Haze planning team could not locate recent emissions test reports for Blanco Compressor Station A Units A-01, A-05, A-06, A-07, A-08, A-10, A-12, or A-14, so we used average emissions from the other units as a surrogate for purposes of calculating baseline actual emissions. If available, please provide our team the most recent emissions test reports for these units so we can further refine our analysis.

An updated overall timeline for the formal FLM review period and proposed hearing phase for New Mexico's Regional Haze State Implementation Plan for the second planning period will soon be available on our NMED Regional Haze planning website: https://www.env.nm.gov/air-quality/reg-haze/.

If you have any questions or feedback for our Regional Haze planning team, please contact me, Kirby Olson (Kirby.olson@env.nm.gov) and cc Mark Jones (mark.jones@env.nm.gov), Ken Miller (kenneth.miller@env.nm.gov) and Alex Sanchez (alex.sanchez@env.nm.gov).

Regards,

Kirby Olson

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Kirby Sue Olson, Ph.D.
Planning Section Chief
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Phone: (505) 629-5107
Fax: (505) 476-4375
kirby.olson@env.nm.gov
https://www.env.nm.gov

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From:	Olson, Kirby, ENV
To:	Miro, Alena M.
Cc:	Acosta, Lynn; Egan, Kerry L; Jones, Mark, ENV; Miller, Kenneth, ENV; Sanchez, Alex, ENV
Subject:	Draft Final Control Cost Evaluations for ETC Transwestern Pipeline"s Facilities
Date:	Wednesday, December 13, 2023 11:39:51 AM
Attachments:	2023-12-13_Draft Final NMED Cost Evaluation_ETC TWP - Mountainair Compressor Station No 7.xlsx 2023-12-13_Draft Final NMED Cost Evaluation_ETC TWP - Roswell Compressor Station No 9.xlsx

Dear Ms. Miro,

Please find NMED's draft final control cost evaluation for the Regional Haze Second Planning Period for ETC Transwestern Pipeline, LLC's Mountainair Compressor Station No. 7 and Roswell Compressor Station No. 9 in the Excel workbook attached to this email.

We are providing this draft final evaluation as a courtesy so you can review it before NMED completes its draft SIP and begins the formal Federal Land Manager (FLM) consultation period required by EPA's Regional Haze Rule. Please review the sheets in the attached workbook for any errors or omissions in incorporating information that your company has previously submitted to NMED. Also, please use this opportunity to notify us of any previously undisclosed changes at your facility that could affect our pending control determinations, such as the decommissioning or replacement of units subject to Regional Haze, the addition of new pollution controls, or facility shutdowns. We reiterate that we are interested in any errors or omissions that you see as well as significant operational changes. For cases involving modifying or decommissioning units, relevant information would include how these are permitted to satisfy EPA's requirement that they be permanent and federally enforceable. Because NMED provided an opportunity to update cost information in summer and early fall 2023, we are no longer accepting updates to cost estimates. **The deadline to submit review comments by email to NMED is Jan 15, 2024**. We may not have time to review comments received after this deadline prior to completing our draft SIP.

ETC Texas Pipeline LTD's Jal No.3 Gas Plant – Based on updated information provided by ETC (2023-07-31), most of the units subject to Regional Haze Second Planning Period including Unit 4A, 4B and 9S have been removed from the permit and decommissioned. Therefore no additional cost evaluation is necessary for these units. For the remaining units (amine unit controlled by AGI and flare(s)) we will consider the flares and associated flaring emissions in a separate analysis for multiple facilities.

An updated overall timeline for the formal FLM review period and proposed hearing phase for New Mexico's Regional Haze State Implementation Plan for the second planning period will soon be available on our NMED Regional Haze planning website: https://www.env.nm.gov/air-quality/reg-haze/.

If you have any questions or feedback for our Regional Haze planning team, please contact me, Kirby Olson (Kirby.olson@env.nm.gov) and cc Mark Jones (mark.jones@env.nm.gov), Ken Miller (kenneth.miller@env.nm.gov) and Alex Sanchez (alex.sanchez@env.nm.gov).

Regards,

Kirby Olson

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Kirby Sue Olson, Ph.D.
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https://www.env.nm.gov

"Science, Innovation, Collaboration, Compliance"

From:	Olson, Kirby, ENV
To:	Monica Smith
Cc:	Jones, Mark, ENV; Miller, Kenneth, ENV; Sanchez, Alex, ENV
Subject:	Draft Final Control Cost Evaluation for Harvest Four Corners" Kutz Canyon Processing Plant
Date:	Wednesday, December 13, 2023 2:41:32 PM
Attachments:	2023-12-13_Draft Final NMED Cost Evaluation_Harvest Four Corners - Kutz Canyon Processing Plant.xlsx

Dear Ms. Smith,

Please find NMED's draft final control cost evaluation for the Regional Haze Second Planning Period for Harvest Four Corners, LLC's Kutz Canyon Processing Plant in the Excel workbook attached to this email.

We are providing this draft final evaluation as a courtesy so you can review it before NMED completes its draft SIP and begins the formal Federal Land Manager (FLM) consultation period required by EPA's Regional Haze Rule. Please review the sheets in the attached workbook for any errors or omissions in incorporating information that your company has previously submitted to NMED. Also, please use this opportunity to notify us of any previously undisclosed changes at your facility that could affect our pending control determinations, such as the decommissioning or replacement of units subject to Regional Haze, the addition of new pollution controls, or facility shutdowns. We reiterate that we are interested in any errors or omissions that you see as well as significant operational changes. For cases involving modifying or decommissioning units, relevant information would include how these are permitted to satisfy EPA's requirement that they be permanent and federally enforceable. Because NMED provided an opportunity to update cost information in summer and early fall 2023, we are no longer accepting updates to cost estimates. **The deadline to submit review comments by email to NMED is Jan 15, 2024**. We may not have time to review comments received after this deadline prior to completing our draft SIP.

An updated overall timeline for the formal FLM review period and proposed hearing phase for New Mexico's Regional Haze State Implementation Plan for the second planning period will soon be available on our NMED Regional Haze planning website: https://www.env.nm.gov/air-quality/reg-haze/.

If you have any questions or feedback for our Regional Haze planning team, please contact me, Kirby Olson (Kirby.olson@env.nm.gov) and cc Mark Jones (mark.jones@env.nm.gov), Ken Miller (kenneth.miller@env.nm.gov) and Alex Sanchez (alex.sanchez@env.nm.gov).

Regards,

Kirby Olson

This email is intended to serve as general guidance and is in no way a formal statement of Department policy. Unique operating conditions may result in different determinations and may require a site specific analysis to accurately determine requirements and applicability.

Kirby Sue Olson, Ph.D.

Planning Section Chief
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"Science, Innovation, Collaboration, Compliance"

From:	Olson, Kirby, ENV
To:	Clara Cardoza
Cc:	Kevin Reese; Jones, Mark, ENV; Miller, Kenneth, ENV; Sanchez, Alex, ENV
Subject:	Draft Final Control Cost Evaluation for Hilcorp Energy Company"s San Juan Basin Gas Plant
Date:	Wednesday, December 13, 2023 4:49:43 PM
Attachments:	2023-12-13_Draft Final NMED Cost Evaluation_Hilcorp - San Juan Basin Gas Plant.xlsx

Dear Ms. Cardoza,

Please find NMED's draft final control cost evaluation for the Regional Haze Second Planning Period for Hilcorp Energy Company's San Juan Basin Gas Plant in the Excel workbook attached to this email.

We are providing this draft final evaluation as a courtesy so you can review it before NMED completes its draft SIP and begins the formal Federal Land Manager (FLM) consultation period required by EPA's Regional Haze Rule. Please review the sheets in the attached workbook for any errors or omissions in incorporating information that your company has previously submitted to NMED. Also, please use this opportunity to notify us of any previously undisclosed changes at your facility that could affect our pending control determinations, such as the decommissioning or replacement of units subject to Regional Haze, the addition of new pollution controls, or facility shutdowns. We reiterate that we are interested in any errors or omissions that you see as well as significant operational changes. For cases involving modifying or decommissioning units, relevant information would include how these are permitted to satisfy EPA's requirement that they be permanent and federally enforceable. Because NMED provided an opportunity to update cost information in summer and early fall 2023, we are no longer accepting updates to cost estimates. **The deadline to submit review comments by email to NMED is Jan 15, 2024**. We may not have time to review comments received after this deadline prior to completing our draft SIP.

NMED has not yet completed its analysis of the San Juan Basin Gas Plant's process flaring and SSM flaring emissions. We will consider these emissions in a separate analysis covering multiple facilities unless we determine that a facility-specific analysis is required for San Juan Basin Gas Plant.

An updated overall timeline for the formal FLM review period and proposed hearing phase for New Mexico's Regional Haze State Implementation Plan for the second planning period will soon be available on our NMED Regional Haze planning website: https://www.env.nm.gov/air-quality/reg-haze/.

If you have any questions or feedback for our Regional Haze planning team, please contact me, Kirby Olson (Kirby.olson@env.nm.gov) and cc Mark Jones (mark.jones@env.nm.gov), Ken Miller (kenneth.miller@env.nm.gov) and Alex Sanchez (alex.sanchez@env.nm.gov).

Regards,

Kirby Olson

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"Science, Innovation, Collaboration, Compliance"

From:	Olson, Kirby, ENV
To:	Tony Hines
Cc:	Homer Trujillo; David McWethy; Jones, Mark, ENV; Miller, Kenneth, ENV; Sanchez, Alex, ENV
Subject:	Draft Final Control Cost Evaluation for IACX Roswell"s Bitter Lake Compressor Station
Date:	Tuesday, December 12, 2023 4:47:42 PM
Attachments:	2023-12-13_Draft Final NMED Cost Evaluation_IACX Roswell - Bitter Lake Compressor Station.xlsx

Dear Mr. Hines,

Please find NMED's draft final control cost evaluation for the Regional Haze Second Planning Period for IACX Roswell, LLC's Bitter Lake Compressor Station in the Excel workbook attached to this email.

We are providing this draft final evaluation as a courtesy so you can review it before NMED completes its draft SIP and begins the formal Federal Land Manager (FLM) consultation period required by EPA's Regional Haze Rule. Please review the sheets in the attached workbook for any errors or omissions in incorporating information that your company has previously submitted to NMED. Also, please use this opportunity to notify us of any previously undisclosed changes at your facility that could affect our pending control determinations, such as the decommissioning or replacement of units subject to Regional Haze, the addition of new pollution controls, or facility shutdowns. We reiterate that we are interested in any errors or omissions that you see as well as significant operational changes. For cases involving modifying or decommissioning units, relevant information would include how these are permitted to satisfy EPA's requirement that they be permanent and federally enforceable. Because NMED provided an opportunity to update cost information in summer and early fall 2023, we are no longer accepting updates to cost estimates. **The deadline to submit review comments by email to NMED is Jan 15, 2024**. We may not have time to review comments received after this deadline prior to completing our draft SIP.

Our NMED Regional Haze planning team could not locate the most recent (November 2022) stack test for Permit Unit #C-893 for purposes of estimating projected actual emissions. If available, please provide our team the most current stack test report for Permit Unit #C-893.

An updated overall timeline for the formal FLM review period and proposed hearing phase for New Mexico's Regional Haze State Implementation Plan for the second planning period will soon be available on our NMED Regional Haze planning website: https://www.env.nm.gov/air-quality/reg-haze/.

If you have any questions or feedback for our Regional Haze planning team, please contact me, Kirby Olson (Kirby.olson@env.nm.gov) and cc Mark Jones (mark.jones@env.nm.gov), Ken Miller (kenneth.miller@env.nm.gov) and Alex Sanchez (alex.sanchez@env.nm.gov).

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Kirby Olson

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"Science, Innovation, Collaboration, Compliance"

From:	Olson, Kirby, ENV
To:	Roberts, Melanie A.
Cc:	Klein, Cynthia S.; Grygar, Bill W.; Jones, Mark, ENV; Miller, Kenneth, ENV; Sanchez, Alex, ENV
Subject:	Draft Final Control Cost Evaluations for Targa Midstream Services, LLC"s Facilities
Date:	Friday, December 15, 2023 1:54:35 PM
Attachments:	2023-12-15_Draft Final NMED Cost Evaluation_Targa - Saunders Gas Plant.xlsx 2023-12-15_Draft Final NMED Cost Evaluation_Targa - Monument Gas Plant.xlsx 2023-12-15_Draft Final NMED Cost Evaluation_Targa - Eunice Gas Processing Plant.xlsx

Dear Ms. Roberts,

Please find NMED's draft final control cost evaluations for the Regional Haze Second Planning Period for Targa Midstream Services, LLC's Eunice Gas Processing Plant, Monument Gas Plant and Saunders Gas Plant in the Excel workbooks attached to this email.

We are providing these draft final evaluations as a courtesy so you can review them before NMED completes its draft SIP and begins the formal Federal Land Manager (FLM) consultation period required by EPA's Regional Haze Rule. Please review the sheets in the attached workbooks for any errors or omissions in incorporating information that your company has previously submitted to NMED. Also, please use this opportunity to notify us of any previously undisclosed changes at your facilities that could affect our pending control determinations, such as the decommissioning or replacement of units subject to Regional Haze, the addition of new pollution controls, or facility shutdowns. We reiterate that we are interested in any errors or omissions that you see as well as significant operational changes. For cases involving modifying or decommissioning units, relevant information would include how these are permitted to satisfy EPA's requirement that they be permanent and federally enforceable. Because NMED provided an opportunity to update cost information in summer and early fall 2023, we are no longer accepting updates to cost estimates. **The deadline to submit review comments by email to NMED is Jan 15, 2024**. We may not have time to review comments received after this deadline prior to completing our draft SIP.

Our NMED Regional Haze planning team could not locate recent emissions test reports for Monument Units C-01 and C-04 or Eunice Units C-02 and C-07, so we used emissions from other units as a surrogate for purposes of calculating baseline actual emissions. If available, please provide our team the most recent emissions test reports for these units so we can further refine our analysis.

NMED has not yet completed its analysis of process flaring and SSM flaring emissions at Targa facilities. We will consider these emissions in a separate analysis covering multiple facilities unless we determine that a facility-specific analysis is required for any of Targa's facilities.

An updated overall timeline for the formal FLM review period and proposed hearing phase for New Mexico's Regional Haze State Implementation Plan for the second planning period will soon be available on our NMED Regional Haze planning website: https://www.env.nm.gov/air-quality/reg-haze/.

If you have any questions or feedback for our Regional Haze planning team, please contact me, Kirby Olson (Kirby.olson@env.nm.gov) and cc Mark Jones (mark.jones@env.nm.gov), Ken Miller

(kenneth.miller@env.nm.gov) and Alex Sanchez (alex.sanchez@env.nm.gov).

Regards,

Kirby Olson

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"Science, Innovation, Collaboration, Compliance"

From:	Olson, Kirby, ENV
To:	karalee.d.snyder@xcelenergy.com
Cc:	Worley, Kevin L; chris.rogers@xcelenergy.com; Jones, Mark, ENV; Miller, Kenneth, ENV; Sanchez, Alex, ENV
Subject:	Draft Final Control Cost Evaluation for Xcel Energy - Southwestern Public Service Company"s Cunningham Station Power Plant
Date:	Thursday, December 14, 2023 12:27:07 PM
Attachments:	2023-12-14_Draft Final NMED Cost Evaluation_Xcel Energy - Cunningham Station Power Plant.xlsx

Dear Ms. Snyder,

Please find NMED's draft final control cost evaluation for the Regional Haze Second Planning Period for Xcel Energy - Southwestern Public Service Company's Cunningham Station Power Plant in the Excel workbook attached to this email.

We are providing this draft final evaluation as a courtesy so you can review it before NMED completes its draft SIP and begins the formal Federal Land Manager (FLM) consultation period required by EPA's Regional Haze Rule. Please review the sheets in the attached workbook for any errors or omissions in incorporating information that your company has previously submitted to NMED. Also, please use this opportunity to notify us of any previously undisclosed changes at your facility that could affect our pending control determinations, such as the decommissioning or replacement of units subject to Regional Haze, the addition of new pollution controls, or facility shutdowns. We reiterate that we are interested in any errors or omissions that you see as well as significant operational changes. For cases involving modifying or decommissioning units, relevant information would include how these are permitted to satisfy EPA's requirement that they be permanent and federally enforceable. Because NMED provided an opportunity to update cost information in summer and early fall 2023, we are no longer accepting updates to cost estimates. **The deadline to submit review comments by email to NMED is Jan 15, 2024**. We may not have time to review comments received after this deadline prior to completing our draft SIP.

Our NMED Regional Haze planning team could not locate a recent RATA/CEMS recertification report for Cunningham Unit 1, so we used emissions from Unit 2 as a surrogate for purposes of calculating baseline actual emissions. If available, please provide our team the most recent RATA/CEMS recertification report for Unit 1 so we can further refine our analysis.

An updated overall timeline for the formal FLM review period and proposed hearing phase for New Mexico's Regional Haze State Implementation Plan for the second planning period will soon be available on our NMED Regional Haze planning website: https://www.env.nm.gov/air-quality/reg-haze/.

If you have any questions or feedback for our Regional Haze planning team, please contact me, Kirby Olson (Kirby.olson@env.nm.gov) and cc Mark Jones (mark.jones@env.nm.gov), Ken Miller (kenneth.miller@env.nm.gov) and Alex Sanchez (alex.sanchez@env.nm.gov).

Regards,

Kirby Olson

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"Science, Innovation, Collaboration, Compliance"

From:	Jones, Mark, ENV
To:	Gannon, Maureen; Horn, Claudette
Cc:	Miller, Kenneth, ENV; Sanchez, Alex, ENV; Butt, Neal, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV
Subject:	Notification of Upcoming Availability of Public Review Drafts of Regional Haze SIP Revision and Companion Rule 20.2.68 NMAC
Date:	Monday, August 19, 2024 4:54:30 PM

Dear Ms. Gannon and Ms. Horn,

NMED is working to complete its draft Regional Haze state implementation plan (SIP) revision for the second planning period (2019-2028) in anticipation of petitioning the New Mexico Environmental Improvement Board (EIB) to hold a hearing on the plan in late fall or early winter. We recently completed the formal 60-day Federal Land Manager (FLM) consultation period required by the Regional Haze Rule and are considering FLM comments on our draft SIP. After we have reviewed all FLM comments and made any necessary changes to the draft SIP, we plan to release public review drafts of the SIP and a companion rule, 20.2.68 NMAC – Regional Haze Requirements, for review and comment by members of the public, industry, and other stakeholders before finalizing the plan and rule and formally proposing them to the EIB. The purpose of the companion rule is to establish enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress during the second planning period, and provisions to make these measures practically enforceable.

We anticipate sharing the public review drafts via our website, https://www.env.nm.gov/air-quality/reg-haze/, on or about **August 26, 2024**. As an affected entity, we are giving you advance notice of the upcoming review period, and we will be requesting that you submit any feedback or comments to us by the end of the day on **September 20, 2024**. There will be no extensions granted on this deadline, as we will be starting the next phase of this process in October, and we want to ensure that we have sufficient time to consider any comments received before the next phase begins. We note that you can also submit comments on the proposed plan during the formal 30-day public comment period that precedes the hearing. Although the exact dates are not known at this time, we will be providing updates on our Regional Haze website (https://www.env.nm.gov/air-quality/reg-haze/) as we continue through this process. Once notice of the hearing has been published in the New Mexico Register, the proposed SIP and related documents will be posted to our public notices web page (https://www.env.nm.gov/public-notices/), and the formal public comment period will begin. We anticipate this will occur sometime in November, barring any unexpected delays.

If you have any questions or feedback for the NMED Regional Haze planning team, please contact me, Mark Jones (mark.jones@env.nm.gov), and cc Ken Miller (kenneth.miller@env.nm.gov), Alex Sanchez (alex.sanchez@env.nm.gov), and Eric Peters (eric.peters@env.nm.gov).

Sincerely,

Mark

Mark Jones | Environmental Analyst
Regional Haze Planning Team
NMED Air Quality Bureau | www.env.nm.gov/air-quality/
mark.jones@env.nm.gov | (505) 629-6626

"Science | Innovation | Collaboration | Compliance"

From:	Jones, Mark, ENV
To:	Cook, John W; Cook, John W
Cc:	Torpey, Steve; Elena Hofmann; Miller, Kenneth, ENV; Sanchez, Alex, ENV; Butt, Neal, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV
Subject:	Notification of Upcoming Availability of Public Review Drafts of Regional Haze SIP Revision and Companion Rule 20.2.68 NMAC
Date:	Monday, August 19, 2024 4:47:06 PM

Dear Mr. Cook,

NMED is working to complete its draft Regional Haze state implementation plan (SIP) revision for the second planning period (2019-2028) in anticipation of petitioning the New Mexico Environmental Improvement Board (EIB) to hold a hearing on the plan in late fall or early winter. We recently completed the formal 60-day Federal Land Manager (FLM) consultation period required by the Regional Haze Rule and are considering FLM comments on our draft SIP. After we have reviewed all FLM comments and made any necessary changes to the draft SIP, we plan to release public review drafts of the SIP and a companion rule, 20.2.68 NMAC – Regional Haze Requirements, for review and comment by members of the public, industry, and other stakeholders before finalizing the plan and rule and formally proposing them to the EIB. The purpose of the companion rule is to establish enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress during the second planning period, and provisions to make these measures practically enforceable.

We anticipate sharing the public review drafts via our website, https://www.env.nm.gov/air-quality/reg-haze/, on or about **August 26, 2024**. As an affected entity, we are giving you advance notice of the upcoming review period, and we will be requesting that you submit any feedback or comments to us by the end of the day on **September 20, 2024**. There will be no extensions granted on this deadline, as we will be starting the next phase of this process in October, and we want to ensure that we have sufficient time to consider any comments received before the next phase begins. We note that you can also submit comments on the proposed plan during the formal 30-day public comment period that precedes the hearing. Although the exact dates are not known at this time, we will be providing updates on our Regional Haze website (https://www.env.nm.gov/air-quality/reg-haze/) as we continue through this process. Once notice of the hearing has been published in the New Mexico Register, the proposed SIP and related documents will be posted to our public notices web page (https://www.env.nm.gov/public-notices/), and the formal public comment period will begin. We anticipate this will occur sometime in November, barring any unexpected delays.

If you have any questions or feedback for the NMED Regional Haze planning team, please contact me, Mark Jones (mark.jones@env.nm.gov), and cc Ken Miller (kenneth.miller@env.nm.gov), Alex Sanchez (alex.sanchez@env.nm.gov), and Eric Peters (eric.peters@env.nm.gov).

Sincerely,

Mark

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Regional Haze Planning Team
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"Science | Innovation | Collaboration | Compliance"

From:	Jones, Mark, ENV
To:	Jacobson, Tucker
Cc:	bjcooley@eprod.com; zlcraft@eprod.com; pkulkarni@eprod.com; Miller, Kenneth, ENV; Sanchez, Alex, ENV; Butt, Neal, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV
Subject:	Notification of Upcoming Availability of Public Review Drafts of Regional Haze SIP Revision and Companion Rule 20.2.68 NMAC
Date:	Monday, August 19, 2024 4:23:23 PM

Dear Mr. Jacobson,

NMED is working to complete its draft Regional Haze state implementation plan (SIP) revision for the second planning period (2019-2028) in anticipation of petitioning the New Mexico Environmental Improvement Board (EIB) to hold a hearing on the plan in late fall or early winter. We recently completed the formal 60-day Federal Land Manager (FLM) consultation period required by the Regional Haze Rule and are considering FLM comments on our draft SIP. After we have reviewed all FLM comments and made any necessary changes to the draft SIP, we plan to release public review drafts of the SIP and a companion rule, 20.2.68 NMAC – Regional Haze Requirements, for review and comment by members of the public, industry, and other stakeholders before finalizing the plan and rule and formally proposing them to the EIB. The purpose of the companion rule is to establish enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress during the second planning period, and provisions to make these measures practically enforceable.

We anticipate sharing the public review drafts via our website, https://www.env.nm.gov/air-quality/reg-haze/, on or about **August 26, 2024**. As an affected entity, we are giving you advance notice of the upcoming review period, and we will be requesting that you submit any feedback or comments to us by the end of the day on **September 20, 2024**. There will be no extensions granted on this deadline, as we will be starting the next phase of this process in October, and we want to ensure that we have sufficient time to consider any comments received before the next phase begins. We note that you can also submit comments on the proposed plan during the formal 30-day public comment period that precedes the hearing. Although the exact dates are not known at this time, we will be providing updates on our Regional Haze website (https://www.env.nm.gov/air-quality/reg-haze/) as we continue through this process. Once notice of the hearing has been published in the New Mexico Register, the proposed SIP and related documents will be posted to our public notices web page (https://www.env.nm.gov/public-notices/), and the formal public comment period will begin. We anticipate this will occur sometime in November, barring any unexpected delays.

If you have any questions or feedback for the NMED Regional Haze planning team, please contact me, Mark Jones (mark.jones@env.nm.gov), and cc Ken Miller (kenneth.miller@env.nm.gov), Alex Sanchez (alex.sanchez@env.nm.gov), and Eric Peters (eric.peters@env.nm.gov).

Sincerely,

Mark

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Regional Haze Planning Team
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mark.jones@env.nm.gov | (505) 629-6626

"Science | Innovation | Collaboration | Compliance"

From:	Jones, Mark, ENV
To:	Tom_Mitchell@kindermorgan.com
Cc:	Duarte, Ricardo (Richard); Daly, Weiwen; Miller, Kenneth, ENV; Sanchez, Alex, ENV; Butt, Neal, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV
Subject:	Notification of Upcoming Availability of Public Review Drafts of Regional Haze SIP Revision and Companion Rule 20.2.68 NMAC
Date:	Monday, August 19, 2024 3:43:44 PM

Dear Mr. Mitchell,

NMED is working to complete its draft Regional Haze state implementation plan (SIP) revision for the second planning period (2019-2028) in anticipation of petitioning the New Mexico Environmental Improvement Board (EIB) to hold a hearing on the plan in late fall or early winter. We recently completed the formal 60-day Federal Land Manager (FLM) consultation period required by the Regional Haze Rule and are considering FLM comments on our draft SIP. After we have reviewed all FLM comments and made any necessary changes to the draft SIP, we plan to release public review drafts of the SIP and a companion rule, 20.2.68 NMAC – Regional Haze Requirements, for review and comment by members of the public, industry, and other stakeholders before finalizing the plan and rule and formally proposing them to the EIB. The purpose of the companion rule is to establish enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress during the second planning period, and provisions to make these measures practically enforceable.

We anticipate sharing the public review drafts via our website, https://www.env.nm.gov/air-quality/reg-haze/, on or about **August 26, 2024**. As an affected entity, we are giving you advance notice of the upcoming review period, and we will be requesting that you submit any feedback or comments to us by the end of the day on **September 20, 2024**. There will be no extensions granted on this deadline, as we will be starting the next phase of this process in October, and we want to ensure that we have sufficient time to consider any comments received before the next phase begins. We note that you can also submit comments on the proposed plan during the formal 30-day public comment period that precedes the hearing. Although the exact dates are not known at this time, we will be providing updates on our Regional Haze website (https://www.env.nm.gov/air-quality/reg-haze/) as we continue through this process. Once notice of the hearing has been published in the New Mexico Register, the proposed SIP and related documents will be posted to our public notices web page (https://www.env.nm.gov/public-notices/), and the formal public comment period will begin. We anticipate this will occur sometime in November, barring any unexpected delays.

If you have any questions or feedback for the NMED Regional Haze planning team, please contact me, Mark Jones (mark.jones@env.nm.gov), and cc Ken Miller (kenneth.miller@env.nm.gov), Alex Sanchez (alex.sanchez@env.nm.gov), and Eric Peters (eric.peters@env.nm.gov).

Sincerely,

Mark

Mark Jones | Environmental Analyst
Regional Haze Planning Team
NMED Air Quality Bureau | www.env.nm.gov/air-quality/

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"Science | Innovation | Collaboration | Compliance"

From:	Jones, Mark, ENV
To:	Miro, Alena M.; Kerry.Egan@energytransfer.com
Cc:	Acosta, Lynn; Miller, Kenneth, ENV; Sanchez, Alex, ENV; Butt, Neal, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV
Subject:	Notification of Upcoming Availability of Public Review Drafts of Regional Haze SIP Revision and Companion Rule 20.2.68 NMAC
Date:	Monday, August 19, 2024 4:20:31 PM

Dear Ms. Miro and Mr. Egan,

NMED is working to complete its draft Regional Haze state implementation plan (SIP) revision for the second planning period (2019-2028) in anticipation of petitioning the New Mexico Environmental Improvement Board (EIB) to hold a hearing on the plan in late fall or early winter. We recently completed the formal 60-day Federal Land Manager (FLM) consultation period required by the Regional Haze Rule and are considering FLM comments on our draft SIP. After we have reviewed all FLM comments and made any necessary changes to the draft SIP, we plan to release public review drafts of the SIP and a companion rule, 20.2.68 NMAC – Regional Haze Requirements, for review and comment by members of the public, industry, and other stakeholders before finalizing the plan and rule and formally proposing them to the EIB. The purpose of the companion rule is to establish enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress during the second planning period, and provisions to make these measures practically enforceable.

We anticipate sharing the public review drafts via our website, https://www.env.nm.gov/air-quality/reg-haze/, on or about **August 26, 2024**. As an affected entity, we are giving you advance notice of the upcoming review period, and we will be requesting that you submit any feedback or comments to us by the end of the day on **September 20, 2024**. There will be no extensions granted on this deadline, as we will be starting the next phase of this process in October, and we want to ensure that we have sufficient time to consider any comments received before the next phase begins. We note that you can also submit comments on the proposed plan during the formal 30-day public comment period that precedes the hearing. Although the exact dates are not known at this time, we will be providing updates on our Regional Haze website (https://www.env.nm.gov/air-quality/reg-haze/) as we continue through this process. Once notice of the hearing has been published in the New Mexico Register, the proposed SIP and related documents will be posted to our public notices web page (https://www.env.nm.gov/public-notices/), and the formal public comment period will begin. We anticipate this will occur sometime in November, barring any unexpected delays.

If you have any questions or feedback for the NMED Regional Haze planning team, please contact me, Mark Jones (mark.jones@env.nm.gov), and cc Ken Miller (kenneth.miller@env.nm.gov), Alex Sanchez (alex.sanchez@env.nm.gov), and Eric Peters (eric.peters@env.nm.gov).

Sincerely,

Mark

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Regional Haze Planning Team
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mark.jones@env.nm.gov | (505) 629-6626

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From:	Jones, Mark, ENV
To:	Monica Smith
Cc:	Miller, Kenneth, ENV; Sanchez, Alex, ENV; Butt, Neal, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV
Subject:	Notification of Upcoming Availability of Public Review Drafts of Regional Haze SIP Revision and Companion Rule 20.2.68 NMAC
Date:	Monday, August 19, 2024 4:12:56 PM

Dear Ms. Smith,

NMED is working to complete its draft Regional Haze state implementation plan (SIP) revision for the second planning period (2019-2028) in anticipation of petitioning the New Mexico Environmental Improvement Board (EIB) to hold a hearing on the plan in late fall or early winter. We recently completed the formal 60-day Federal Land Manager (FLM) consultation period required by the Regional Haze Rule and are considering FLM comments on our draft SIP. After we have reviewed all FLM comments and made any necessary changes to the draft SIP, we plan to release public review drafts of the SIP and a companion rule, 20.2.68 NMAC – Regional Haze Requirements, for review and comment by members of the public, industry, and other stakeholders before finalizing the plan and rule and formally proposing them to the EIB. The purpose of the companion rule is to establish enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress during the second planning period, and provisions to make these measures practically enforceable.

We anticipate sharing the public review drafts via our website, https://www.env.nm.gov/air-quality/reg-haze/, on or about **August 26, 2024**. As an affected entity, we are giving you advance notice of the upcoming review period, and we will be requesting that you submit any feedback or comments to us by the end of the day on **September 20, 2024**. There will be no extensions granted on this deadline, as we will be starting the next phase of this process in October, and we want to ensure that we have sufficient time to consider any comments received before the next phase begins. We note that you can also submit comments on the proposed plan during the formal 30-day public comment period that precedes the hearing. Although the exact dates are not known at this time, we will be providing updates on our Regional Haze website (https://www.env.nm.gov/air-quality/reg-haze/) as we continue through this process. Once notice of the hearing has been published in the New Mexico Register, the proposed SIP and related documents will be posted to our public notices web page (https://www.env.nm.gov/public-notices/), and the formal public comment period will begin. We anticipate this will occur sometime in November, barring any unexpected delays.

If you have any questions or feedback for the NMED Regional Haze planning team, please contact me, Mark Jones (mark.jones@env.nm.gov), and cc Ken Miller (kenneth.miller@env.nm.gov), Alex Sanchez (alex.sanchez@env.nm.gov), and Eric Peters (eric.peters@env.nm.gov).

Sincerely,

Mark

Mark Jones | Environmental Analyst
Regional Haze Planning Team
NMED Air Quality Bureau | www.env.nm.gov/air-quality/
mark.jones@env.nm.gov | (505) 629-6626

"Science | Innovation | Collaboration | Compliance"

From:	Jones, Mark, ENV
To:	Clara Cardoza
Cc:	Kevin Reese; Miller, Kenneth, ENV; Sanchez, Alex, ENV; Butt, Neal, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV
Subject:	Notification of Upcoming Availability of Public Review Drafts of Regional Haze SIP Revision and Companion Rule 20.2.68 NMAC
Date:	Monday, August 19, 2024 4:07:00 PM

Dear Ms. Cardoza,

NMED is working to complete its draft Regional Haze state implementation plan (SIP) revision for the second planning period (2019-2028) in anticipation of petitioning the New Mexico Environmental Improvement Board (EIB) to hold a hearing on the plan in late fall or early winter. We recently completed the formal 60-day Federal Land Manager (FLM) consultation period required by the Regional Haze Rule and are considering FLM comments on our draft SIP. After we have reviewed all FLM comments and made any necessary changes to the draft SIP, we plan to release public review drafts of the SIP and a companion rule, 20.2.68 NMAC – Regional Haze Requirements, for review and comment by members of the public, industry, and other stakeholders before finalizing the plan and rule and formally proposing them to the EIB. The purpose of the companion rule is to establish enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress during the second planning period, and provisions to make these measures practically enforceable.

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If you have any questions or feedback for the NMED Regional Haze planning team, please contact me, Mark Jones (mark.jones@env.nm.gov), and cc Ken Miller (kenneth.miller@env.nm.gov), Alex Sanchez (alex.sanchez@env.nm.gov), and Eric Peters (eric.peters@env.nm.gov).

Sincerely,

Mark

Mark Jones | Environmental Analyst
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mark.jones@env.nm.gov | (505) 629-6626

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From:	Jones, Mark, ENV
To:	tonyhines@iacx.com
Cc:	homertrujillo@iacxroswell.com; davidmcwethy@iacx.com; Miller, Kenneth, ENV; Sanchez, Alex, ENV; Peters, Eric, ENV; Butt, Neal, ENV; Hirsch, Josh, ENV
Subject:	Notification of Upcoming Availability of Public Review Drafts of Regional Haze SIP Revision and Companion Rule 20.2.68 NMAC
Date:	Monday, August 19, 2024 3:58:13 PM

Dear Mr. Hines,

NMED is working to complete its draft Regional Haze state implementation plan (SIP) revision for the second planning period (2019-2028) in anticipation of petitioning the New Mexico Environmental Improvement Board (EIB) to hold a hearing on the plan in late fall or early winter. We recently completed the formal 60-day Federal Land Manager (FLM) consultation period required by the Regional Haze Rule and are considering FLM comments on our draft SIP. After we have reviewed all FLM comments and made any necessary changes to the draft SIP, we plan to release public review drafts of the SIP and a companion rule, 20.2.68 NMAC – Regional Haze Requirements, for review and comment by members of the public, industry, and other stakeholders before finalizing the plan and rule and formally proposing them to the EIB. The purpose of the companion rule is to establish enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress during the second planning period, and provisions to make these measures practically enforceable.

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Sincerely,

Mark

Mark Jones | Environmental Analyst
Regional Haze Planning Team
NMED Air Quality Bureau | www.env.nm.gov/air-quality/

mark.jones@env.nm.gov | (505) 629-6626

"Science | Innovation | Collaboration | Compliance"

From:	Jones, Mark, ENV
To:	Femi Serrano
Cc:	Miller, Kenneth, ENV; Sanchez, Alex, ENV; Butt, Neal, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV
Subject:	Notification of Upcoming Availability of Public Review Drafts of Regional Haze SIP Revision and Companion Rule 20.2.68 NMAC
Date:	Monday, August 19, 2024 4:40:44 PM

Dear Ms. Serrano,

NMED is working to complete its draft Regional Haze state implementation plan (SIP) revision for the second planning period (2019-2028) in anticipation of petitioning the New Mexico Environmental Improvement Board (EIB) to hold a hearing on the plan in late fall or early winter. We recently completed the formal 60-day Federal Land Manager (FLM) consultation period required by the Regional Haze Rule and are considering FLM comments on our draft SIP. After we have reviewed all FLM comments and made any necessary changes to the draft SIP, we plan to release public review drafts of the SIP and a companion rule, 20.2.68 NMAC – Regional Haze Requirements, for review and comment by members of the public, industry, and other stakeholders before finalizing the plan and rule and formally proposing them to the EIB. The purpose of the companion rule is to establish enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress during the second planning period, and provisions to make these measures practically enforceable.

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If you have any questions or feedback for the NMED Regional Haze planning team, please contact me, Mark Jones (mark.jones@env.nm.gov), and cc Ken Miller (kenneth.miller@env.nm.gov), Alex Sanchez (alex.sanchez@env.nm.gov), and Eric Peters (eric.peters@env.nm.gov).

Sincerely,

Mark

Mark Jones | Environmental Analyst
Regional Haze Planning Team
NMED Air Quality Bureau | www.env.nm.gov/air-quality/
mark.jones@env.nm.gov | (505) 629-6626

"Science | Innovation | Collaboration | Compliance"

From:	Jones, Mark, ENV
To:	Roberts, Melanie A.
Cc:	Klein, Cynthia S.; Grygar, Bill W.; Miller, Kenneth, ENV; Sanchez, Alex, ENV; Butt, Neal, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV
Subject:	Notification of Upcoming Availability of Public Review Drafts of Regional Haze SIP Revision and Companion Rule 20.2.68 NMAC
Date:	Monday, August 19, 2024 4:29:34 PM

Dear Ms. Roberts,

NMED is working to complete its draft Regional Haze state implementation plan (SIP) revision for the second planning period (2019-2028) in anticipation of petitioning the New Mexico Environmental Improvement Board (EIB) to hold a hearing on the plan in late fall or early winter. We recently completed the formal 60-day Federal Land Manager (FLM) consultation period required by the Regional Haze Rule and are considering FLM comments on our draft SIP. After we have reviewed all FLM comments and made any necessary changes to the draft SIP, we plan to release public review drafts of the SIP and a companion rule, 20.2.68 NMAC – Regional Haze Requirements, for review and comment by members of the public, industry, and other stakeholders before finalizing the plan and rule and formally proposing them to the EIB. The purpose of the companion rule is to establish enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress during the second planning period, and provisions to make these measures practically enforceable.

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If you have any questions or feedback for the NMED Regional Haze planning team, please contact me, Mark Jones (mark.jones@env.nm.gov), and cc Ken Miller (kenneth.miller@env.nm.gov), Alex Sanchez (alex.sanchez@env.nm.gov), and Eric Peters (eric.peters@env.nm.gov).

Sincerely,

Mark

Mark Jones | Environmental Analyst
Regional Haze Planning Team
NMED Air Quality Bureau | www.env.nm.gov/air-quality/

mark.jones@env.nm.gov | (505) 629-6626

"Science | Innovation | Collaboration | Compliance"

From:	Jones, Mark, ENV
To:	Berger, Andy
Cc:	dlempke@tristategt.org; Miller, Kenneth, ENV; Sanchez, Alex, ENV; Butt, Neal, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV
Subject:	Notification of Upcoming Availability of Public Review Drafts of Regional Haze SIP Revision and Companion Rule 20.2.68 NMAC
Date:	Monday, August 19, 2024 4:32:00 PM

Dear Mr. Berger,

NMED is working to complete its draft Regional Haze state implementation plan (SIP) revision for the second planning period (2019-2028) in anticipation of petitioning the New Mexico Environmental Improvement Board (EIB) to hold a hearing on the plan in late fall or early winter. We recently completed the formal 60-day Federal Land Manager (FLM) consultation period required by the Regional Haze Rule and are considering FLM comments on our draft SIP. After we have reviewed all FLM comments and made any necessary changes to the draft SIP, we plan to release public review drafts of the SIP and a companion rule, 20.2.68 NMAC – Regional Haze Requirements, for review and comment by members of the public, industry, and other stakeholders before finalizing the plan and rule and formally proposing them to the EIB. The purpose of the companion rule is to establish enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress during the second planning period, and provisions to make these measures practically enforceable.

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If you have any questions or feedback for the NMED Regional Haze planning team, please contact me, Mark Jones (mark.jones@env.nm.gov), and cc Ken Miller (kenneth.miller@env.nm.gov), Alex Sanchez (alex.sanchez@env.nm.gov), and Eric Peters (eric.peters@env.nm.gov).

Sincerely,

Mark

Mark Jones | Environmental Analyst
Regional Haze Planning Team
NMED Air Quality Bureau | www.env.nm.gov/air-quality/

mark.jones@env.nm.gov | (505) 629-6626

"Science | Innovation | Collaboration | Compliance"

From:	Jones, Mark, ENV
To:	Karalee.D.Snyder@xcelenergy.com
Cc:	Worley, Kevin L; chris.rogers@xcelenergy.com; Miller, Kenneth, ENV; Sanchez, Alex, ENV; Butt, Neal, ENV; Peters, Eric, ENV; Hirsch, Josh, ENV
Subject:	Notification of Upcoming Availability of Public Review Drafts of Regional Haze SIP Revision and Companion Rule 20.2.68 NMAC
Date:	Monday, August 19, 2024 4:36:54 PM

Dear Ms. Snyder,

NMED is working to complete its draft Regional Haze state implementation plan (SIP) revision for the second planning period (2019-2028) in anticipation of petitioning the New Mexico Environmental Improvement Board (EIB) to hold a hearing on the plan in late fall or early winter. We recently completed the formal 60-day Federal Land Manager (FLM) consultation period required by the Regional Haze Rule and are considering FLM comments on our draft SIP. After we have reviewed all FLM comments and made any necessary changes to the draft SIP, we plan to release public review drafts of the SIP and a companion rule, 20.2.68 NMAC – Regional Haze Requirements, for review and comment by members of the public, industry, and other stakeholders before finalizing the plan and rule and formally proposing them to the EIB. The purpose of the companion rule is to establish enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress during the second planning period, and provisions to make these measures practically enforceable.

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If you have any questions or feedback for our Regional Haze planning team, please contact me, Mark Jones (mark.jones@env.nm.gov), and cc Ken Miller (kenneth.miller@env.nm.gov), Alex Sanchez (alex.sanchez@env.nm.gov), and Eric Peters (eric.peters@env.nm.gov).

Sincerely,

Mark

Mark Jones | Environmental Analyst
Regional Haze Planning Team
NMED Air Quality Bureau | www.env.nm.gov/air-quality/

mark.jones@env.nm.gov | (505) 629-6626

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E.6 General Outreach Education and Stakeholder Engagement

Supporting documentation for NMED general outreach, education and stakeholder engagement is provided below. The following documents are included in this section (in reading order):

- Regional Haze Planning Guiding Principles (1/3/19)
- Early Engagement National Parks Conservation Association Comments (5/22/20)
- NPCA comments to NMED regarding - Petition to EPA for Reconsideration of Regional Haze Final Guidance (5/29/20)
- Assessment of Cost Effectiveness Analyses for Controls Evaluated Four – Factor Analyses for Oil and Gas Facilities (7/2/20)
- Draft Regional Haze Plan Informational Webinar (9/9/2024 and 9/10/2024)

Air Quality Bureau

Guiding Principles for Developing the New Mexico Regional Haze State Implementation Plan (RH SIP)

Science

- Use sound scientific analysis and principles to understand visibility issues.
- Perform visibility studies using the most recent, complete, and accurate datasets available.
- Rely upon and lead with science to inform our understanding of the causes of haze, evaluate strategies and set future goals to improve visibility at Class I Areas.

Innovation

- Consider new ideas that potentially offer better solutions to problems of haze at Class I Areas.
- Allow for flexibility in the planning and development of the RH SIP revision to include new information as it becomes available.
- Include and evaluate the newest engineering methods and technology advances in potential control measures to help solve haze problems.

Collaboration

- Assist the Western Regional Air Partnership (WRAP) and its contractors performing regional technical analyses, and collaborate with all western states, Federal Land Managers (FLMs), the U.S. Environmental Protection Agency (EPA) and tribes.
- Work proactively with all stakeholders to minimize negative impacts for sources and maximize visibility improvements at Class I Areas.
- Acknowledge and consider a wide range of perspectives and ideas, regardless of the source, while respecting each person working toward the shared goal of improved visibility at Class I Areas.
- Keep stakeholders informed of all steps required for RH SIP planning and development; help them access technical information that informs the Department's decisions.
- Consult with EPA, FLMs, other states and, where appropriate, tribes at multiple stages in the development of the RH SIP revision.

Compliance

- Maintain a level playing field with the development of fair and equitable reasonable control measures.
- Develop a long-term strategy that ensures continued progress toward visibility goals.
- Assure approvability of the RH SIP revision by complying with federal rule requirements, adhering to EPA guidance and frequently consulting with EPA and FLMs.

Attn: Mark Jones & Cember Hardison
New Mexico Environment Department

May 22, 2020

Dear Mr. Jones and Ms. Hardison,

Thank you for the opportunity to discuss the options available for best mitigating haze-causing pollutants from sources in the oil and gas sector in New Mexico. We appreciate your work to develop a strong regional haze state implementation plan (SIP). While this letter is focused on emission reducing options for engines in the oil and gas sector, as we've identified elsewhere, other facilities in this and other sectors also contribute to regional haze, such as the San Juan Generating Station, and we maintain an interest in seeing the New Mexico haze SIP control pollution from those sources as well.

In response to your request for more information regarding selective catalytic reduction (SCR) for lean burn engines, we have attached an expert report prepared by Victoria Stamper and Megan Williams. As the report describes in detail, SCR is a feasible and cost-effective pollution control option. However, rather than require SCR, we urge NMED to require operators to replace gas-fueled engines with electric motors wherever feasible. To that end, the agency must establish clear and specific criteria for determining "infeasibility." Electrification is ultimately the best option for reducing or eliminating emissions of NO_x (and all other air pollutants from gas-fired engines), thereby better reducing visibility and public health harming emissions while helping New Mexico achieve its climate goals. Electrification can also be highly cost-effective. State and federal regulations establish the authority for NMED to require electrification of gas engines or replacement or set near-zero NO_x emissions limits, as detailed below. Where electrification is not feasible, SCR provides a feasible and cost-effective alternative.

I. Benefits of Electrification

Gas-fired engines used in oil and gas development contribute significantly to NO_x and other air pollution in New Mexico. Electric engines, by contrast, eliminate NO_x and other pollutants, decrease noise levels, and are easier to maintain. Compared to gas-fired engines, electric engines also result in fewer upset events at wells – events that can release large quantities of pollutants, including volatile organic compounds ("VOCs") and methane, a powerful greenhouse gas with 86 times the 20-year global warming potential of CO_2.[1] Mandatory electrification would significantly reduce methane emissions and waste, ozone, and haze, leading to improved air quality and thus improved visibility and health throughout New Mexico. It would also help New Mexico achieve its climate and energy goals, including but not limited to those articulated in Governor Michelle Lujan Grisham's January 2019 Executive Order

[1] *See* Vicki Stamper & Megan Williams, Nat'l Parks Conservation Ass'n, *Oil & Gas Sector Reasonable Progress Four-Factor Analysis of Controls For Five Source Categories* 57 (2020) [hereinafter Stamper & Williams, *Oil and Gas Four-Factor Analysis of Controls*].

2019-003, "Executive Order on Addressing Climate Change and Energy Waste Prevention."[2] Mandatory electrification would also complement and reinforce NMED's (and EMNRD's) ongoing efforts to reduce ozone and methane emissions through the Ozone Attainment Initiative (OAI) and Methane rulemakings, respectively.

Electrification can also be highly cost-effective. In 2001, the California Air Resources Board (CARB) found that electrification of units between 50 and 500 hp can control NOx pollution at a cost of about $900 to $1,100 per ton of NOx reduced.[3] CARB further concluded that for units between 500 and 1,000 hp the installed costs of electrification and internal combustion engines are about the same, and that below 500 hp the installed costs of electrification are lower than the installed costs of comparable internal combustion engines.[4] Given the significant advances in technology during the past 20 years, electrification is likely even more cost effective today.

II. Legal Authority for Electrification

Under state and federal law, NMED has the authority to mandate the electrification of engines used in oil and gas development, and/or to set NO_x emissions limitations near zero to favor electrification. Requiring SCR is also well within the scope of the state's regulatory authority. However, in order to create a SIP that will best meet state and federal clean air objectives, electrification should be required.

A. State Law

Broadly, New Mexico's Air Quality Control Act, Chapter 74, Article 2, NMSA 1978 ("Air Quality Control Act") requires the New Mexico Environmental Improvement Board (Board) to "prevent or abate air pollution."[5] The Board shall "adopt, promulgate, publish, amend and repeal rules and standards consistent with the Air Quality Control Act to attain and maintain national ambient air quality standards and prevent or abate air pollution," and "adopt a plan for the regulation, control, prevention or abatement of air pollution, recognizing the differences, needs, requirements and conditions within the geographic area of the environmental improvement board's jurisdiction . . ."[6]

Further, the Environmental Improvement Board may take action inclusive of "rules to protect visibility in mandatory class I areas to prevent significant deterioration of air quality and to achieve national ambient air quality standards in nonattainment areas . . . "[7] A rule requiring electrification of oil and gas engines would further NMED's duty to prevent or abate air pollution, including via adoption, promulgation, publication, or amendment of rules and adoption of a plan for the regulation, control,

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[2] Executive Order 2019-003, "Executive Order on Addressing Climate Change and Energy Waste Prevention," (January 29, 2019), *Available at* https://www.governor.state.nm.us/wp-content/uploads/2019/01/EO_2019-003.pdf

[3] *Id.* at 41-42. CARB's conservative cost estimate, which is in 1999 dollars, assumed only 2,000 hours of operation each year and a 10-year, rather than a 30-year, life of the equipment. *Id.* at 42; *See generally Id.* at 41-46.

[4] Cal. Air Res. Bd., *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines*, at V-5 (2001), https://ww3.arb.ca.gov/ractbarc/rb-iceall.pdf.

[5] Air Quality Control Act, 74-2-5 (A) NMSA 1978 (emphasis added).

[6] Air Quality Control Act, 74-2-5 (B)(1) and (B)(2) NMSA 1978.

[7] Air Quality Control Act, 74-2-5 (C)(1) and (C)(2) NMSA 1978.

prevention or abatement of air pollution. Mandating electrification would also further NMED's duty to adopt rules to protect visibility in mandatory Class I areas to prevent significant deterioration of air quality.

Electrification would also account for the "character and degree of injury to or interference with health, welfare, visibility, and property" caused by engines and "the public interest, including the social and economic value of the sources *and subjects* of air contaminants."[8] (*Emphasis added*). Electrification of gas-fired RICE engines would eliminate 100% of NOx and other emissions.

These emissions degrade air resources in and around class 1 airsheds, which negatively impacts the health of nearby communities, and undercuts the economic benefits of the national parks and wilderness areas which comprise these airsheds. For example, NOx emissions from increased energy activity in the Permian Basin have led to noted degradation of visibility for park visitors, and repeated instances of 24-hour non-attainment of ozone near Carlsbad Caverns National Park, and deposition of NOx in the area's fragile ecosystem threatens its unique flora and fauna. Damage to the park's resources would greatly harm the area's economy; a 2019 National Park Service report shows that 466,000 visitors to Carlsbad Caverns National Park in 2018 spent $30.2 million in communities near the park. That spending supported 405 jobs in the local area and had a cumulative benefit to the local economy of $34 million.[9]

Given its technical feasibility and cost effectiveness, electrification also ensures that NMED considers measures through the lens of its duty to consider "technical practicability and economic reasonableness of reducing or eliminating air contaminants from the sources involved and previous experience with equipment and methods available to control the air contaminants involved."[10]

Finally, electrification of oil and gas drilling and other operations serves to fulfill cross-cutting initiatives by the state to address various air pollutant emissions. Electrification is mentioned as a pollution control technology for many methane emissions sources. The MAP Technical Report notes that due to the resulting elimination of criteria pollutants, HAPs, and methane, "In some situations, oil and gas operators determine that electrified compression is a viable and preferred technology in place of natural gas fired engines or turbines."(MAP Technical Report p. 99). Further discussion of recommendations for putting electrification into practice can be found in the following sections of the MAP Technical Report, to aid in establishing paths forward for achievement of air quality goals:

- Section 10.4, outlining utility co-op incentives to expand service territories in the pursuit of providing well sites with electricity;
- Section 10.8, recommends the establishment of interagency coordination to more efficiently and speedily develop electrical oilfield infrastructure in cooperation with utilities to manage distributed generation, increasing the ability of operators to cost effectively adopt electrification;
- Section 10.15, recommends that the state allow temporary gen set power on a site, in case of delays in getting line power to the site, mitigating methane as well as haze-causing pollutant emissions.

[8] Air Quality Control Act, 74-2-5 (E)(1) and (E)(2) NMSA 1978.
[9] U.S. National Park Service (NPS), "Tourism to Carlsbad Caverns National Park Creates $34 Million in Economic Benefits" (May 24, 2019), *Available at* https://www.nps.gov/cave/learn/news/tourism-creates-34-million-in-economic-benefits.htm
[10] Air Quality Control Act, 74-2-5 (E)(3) NMSA 1978.

We thus emphasize the need for interagency coordination among waste and pollution regulators and electric utility regulators, including the Public Regulation Commission, to facilitate policies to most effectively enable electrification.

B. Federal Law

In developing the state's regional haze plan under the federal Clean Air Act, the state has discretion to set NOx emissions limitations that favor electrification. In developing a regional haze SIP, a state must include reasonable progress requirements based on consideration of four factors, including the energy and non-air quality environmental impacts of compliance.[11] The state must also develop a long-term strategy for regional haze that includes enforceable emissions limitations, and emissions reduction measures necessary to make reasonable progress.[12] As explained above, and discussed in further detail in the March 6, 2020 report on Reasonable Progress Controls for the Oil and Gas Sector, electrification of engines used in oil and gas development is a cost-effective pollution control strategy with an array of environmental, climate, and public health co-benefits. The cost effectiveness of this NOx pollution control strategy supports requiring electrification of oil and gas engines and establishing a corresponding very low (near-zero) NOx limit for this source category.

Setting low NO_x emissions limits and considering technology that reduces or eliminates emissions, such as electrification, for oil and gas engines is well within the scope of regional haze analysis and SIP development, and is consistent with the Clean Air Act, and regulatory requirements for reasonable progress outlined in 40 C.F.R. § 51.308(d)(1). Regional haze SIPs must contain "emissions limits, schedules of compliance, and other measures as may be necessary to make reasonable progress toward the national goal." 42 U.S.C. § 7491 (b)(2). In determining what emissions reductions measures are needed to make reasonable progress, states must consider four factors: the cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance, and remaining useful life of any potentially affected sources. 40 C.F.R. § 51.308(d)(1)(i)(A). Near-zero NO_x emissions limitations would be well within these parameters–and indeed would have positive energy and non-air quality environmental impacts.

Requiring the replacement of gas-fired engines with electric motors would serve as a reasonable progress measure applicable to a source type and would not constitute "redesigning the source" or otherwise fall outside the allowable scope of the state's regional haze planning authority. These engines assume a variety of applications, including gas compression, pumping, and power generation and the functionality of the source is undisturbed irrespective of whether it is subject to more or less stringent emission limitations. The difference is in the scale of pollution emitted or avoided as determined by the type of control strategy or technology employed to achieve an emission limit in order to help achieve a variety of benefits in the public interest, here motivated by requirements to achieve reasonable progress towards natural visibility conditions.

In looking at other regional haze requirements, the BART Guidelines allow states to "establish design, equipment, work practice or other operational standards when limitations on measurement technologies make emission standards infeasible." 40 C.F.R. Appendix Y to Part 51, Section I (E)(3). More broadly, Clean Air Act programs and analyses such as BACT, and PSD afford considerable flexibility

[11] *See* 40 C.F.R. § 51.308(d)(1)(i)(A), (f)(2)(i), (f)(3)(i).
[12] *See* 40 C.F.R. § 51.308 (f)(2)(i), (f)(3)(i).

to regulators in determining the range and type of pollution reduction practices or control strategies for states to consider as well. As the U.S. EPA Environmental Appeals Board has stated:

> "Permit issuers generally have broad discretion in conducting BACT determinations, but they are strongly discouraged from categorizing emissions control options as "impermissible redesign" without first taking the requisite "hard look" at the project. ***To skip this step might result in their "paving an automatic BACT off-ramp" that "frustrates congressional will" and may constitute a reversible abuse of discretion***. *In re N. Mich. Univ.*, 14 E.A.D. 283, 302 (EAB 2009); *accord La Paloma*, slip op. at 26, 16 E.A.D. ___. "[13] (Emphasis added).

Nothing in the Clean Air Act, applicable regulations or guidance, prohibits emissions limitations that reflect the reductions achievable through electrification. NMED should thus exercise its authority under state and federal law to require that oil and gas operators electrify oil and gas engines by either mandating electrification or establishing a NOx emission limit near 0 g/hp-hr. Doing so will expedite New Mexico's progress toward attaining natural visibility in national parks and other Class I areas, help the state in its Ozone Attainment Initiative and efforts to reduce methane emissions and waste, and help New Mexico achieve its climate goals, including but not limited to those outlined in Governor Lujan Grisham's Executive Order 2019-003.

III. SCR as a Feasible, Cost Effective Option Where Electrification is Infeasible

While replacement of gas-fired engines in oil and gas development with electric motors is our preferred pollution control measure, we recognize that there may be instances in which electrification is not feasible. If electrification is demonstrated to be infeasible in a given case, e.g., when there is no reasonable access or reasonable opportunity to create access to a power grid, we recommend that NMED require selective catalytic reduction (SCR), a cost-effective and practicable option as described in the attached Expert Report and the March 6, 2020 report on Reasonable Progress Controls for the Oil and Gas Sector. Some highlights from the Expert Report include:

- SCR has been an effective, feasible technology applied to lean burn engines for nearly four decades.

- Multiple emissions tests conducted in California for several lean burn engines with SCR showed 84% to 87% NO_x reductions, even after several years of operation.

- While space constraints can be a concern for SCR retrofits, there are several proven ways to address this issue. For example, SCR systems can be installed in place of existing exhaust mufflers on the roof of buildings.

- Given the relatively advanced age of most lean-burn engines for which NMED has requested reasonable progress analysis (with many manufactured before the Clean Air Act was enacted in 1970), NMED should also consider replacing these engines with new engines with

[13] *See, e.g., In Re: Arizona Public Service Company Ocotillo Power Plant,* 17 EAD 323, 336-37 (E.P.A. Sept. 1, 2016) *(citing In re N. Mich. Univ.,* 14 E.A.D. 283, 302 (EAB 2009*); In re La Paloma,* 16 EAD 267, 289 (EAB 2014)). ("Each such determination, like each BACT analysis itself, requires a case-by-case analysis and is highly fact- and circumstance-specific. *La Paloma,* slip op. at 26, 16 E.A.D. at ___ (citing CAA § 169(3), 42 U.S.C. § 7479(3)) (defining "BACT" as a "case-by-case" determination); GHG Guidance at 26.").

state-of-the-art low NO_x emission control technology, or, as advocated throughout this letter, replacing them with electric engines that would eliminate NO_x emissions (and other air pollutant emissions) altogether.

IV. Conclusion

Electrification is a feasible, cost-effective pollution control technology which NMED has the authority to require in its regional haze SIP. In addition to helping NMED achieve reasonable progress towards national visibility goals as required by the Clean Air Act, electrification has several co-benefits for climate, health, and ongoing regulatory and policy initiatives in New Mexico. Thus, we request that NMED require emission limitations as reasonable progress for gas-fueled engines reflective of replacement with electric-motors, with limitations reflective of SCR instead as an option when electrification is not feasible.

Thank you again for your continued engagement with the public during the regional haze SIP development process, even amidst the difficult conditions of the COVID-19 pandemic, and for your consideration of the recommendations and information in this letter and attached Expert Report. Please do not hesitate to contact us with any questions or concerns, or to discuss the attached SCR analysis or electrification further.

Sincerely,

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Review of Claims Made by New Mexico Oil and Gas Companies
Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines

May 21, 2020

By

Victoria Stamper and Megan Williams

We have reviewed most of the claims raised by New Mexico oil and gas companies regarding applicability of selective catalytic reduction (SCR) to lean burn engines and have conducted additional research beyond what was provided in our March 6, 2020 report. We are providing some additional information to address some of the issues raised in the New Mexico company submittals with respect to SCR on lean burn engines. Specifically, claims were raised that SCR has not been proven for lean burn engines or specifically for two-stroke engines.

As discussed in our March 6, 2020 report on Reasonable Progress Controls for the Oil and Gas Sector, SCR has been applied to lean burn engines since the 1980's. EPA's 1993 Alternative Control Techniques Document for RICE said they had found "23 SCR installations with lean-burn SI engines [] in the United States from information provided by catalyst vendors, in addition to over 40 overseas installations."[1]

EPA's 1993 Alternative Control Techniques (ACT) Document for RICE had emissions test information for 16 SCR applications at lean burn engines at 9 installations in California, including for Cooper-Bessemer engines.[2] Specifically, EPA provided performance data from a California vendor for an SCR application on a 660 hp Cooper-Bessemer Engine (Model GMV-6) that achieved 80% NOx control and data for two Cooper-Bessemer engines Model GMV-8 that also achieved 80% control of NOx.[3] Notably, the GMV-8 engines were using a load-following ammonia control, which is best suited for engines operated at variable load. In addition, EPA's 1993 ACT Document also provided emissions test data from California's Ventura County Air Pollution Control District for SCR used with lean burn RICE, including test data from 1987-1990 for two Cooper-Bessemer engines (Models GMV and GMV-8) and several Clark engines (Engine Models HRA-6 and HRA-32).[4] Note, some of the engines were no longer operating at the time of EPA's 1993 ACT Document due to being electrified as a result of Southern California Edison's incentive program.[5]

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[1] March 6, 2020 Report at 34; EPA 1993 Alternative Control Techniques Document for RICE.

[2] U.S. EPA, Alternative Control Techniques Document – NOx Emissions from Stationary Reciprocating Internal Combustion Engines, EPA -453/R-93-032, July 1993, *available at:* https://www3.epa.gov/airquality/ctg_act/199307_nox_epa453_r-93-032_internal_combustion_engines.pdf ("EPA 1993 ACT Document") at 5-61 to 5-62

[3] *Id.* at Table 5-8 at 5-62.

[4] *Id.*, Appendix A at A-16 (Table A-5).

[5] *Id.*

In September 2000, EPA issued an updated report on Stationary RICE controls.[6] Based on that EPA report, we said in our March 2020 report that "…while diesel engines are the most prevalent applications of SCR at RICE units, SCR has also been applied at lean-burn spark-ignition engines fired with natural gas, including at natural gas pipeline compressor stations."[7] The SCR installations at the time of EPA's 1993 and 2000 reports were mostly if not all from California. Several California air districts had adopted NOx limits for existing RICE that required SCR on lean burn engines particularly if low emissions combustion systems would not have allowed the unit to meet the applicable limits (or were not as cost effective as SCR), as was demonstrated in the cost reports relied on or cited in our report.[8]

In EPA's 2000 Update, it discusses one facility that operated SCR on a lean burn engine for 12 years (from 1984-1996). According to EPA, "[t]he SCR system met or exceeded the guaranteed level of NOx control (70 percent), allowing the facility to meet the applicable emission limit."[9] Indeed, emissions testing from 1993 of this lean-burn SCR retrofit as well as another lean-burn engine the company operated with SCR – eight to nine years after SCR installation – showed the SCR achieving between 84 to 87% NOx reduction.[10] This data certainly seems indicative of SCR working to significantly reduce NOx at lean-burn engines. The EPA 2000 Update identifies costs with operating the SCR, including the costs of continuous emissions monitoring systems (CEMs), cost of anhydrous ammonia, and cost of catalyst replacement.[11] The EPA 2000 Update also said that the facility found operation and maintenance required additional work not normally required for an engine.[12] These are cost issues with the control, but SCR is still a technically feasible control. Twelve years of operational data on a lean-burn engine with the engine continuing to meet high levels of NOx control even after several years of operation clearly show that SCR is a demonstrated technology for lean-burn engines. According to EPA, the company subsequently – twelve years after installation of SCR – replaced the engine with Low Emissions Combustion (LEC)-equipped engines.[13] Thus, there is no current emissions data for the engine reflective of SCR.

The EPA 2000 Update also refers to emissions test data from the Ventura County Air Pollution Control District (VCAPCD) for 7 lean burn engines with SCR, ranging in size from 291 bhp to 800 bhp.[14] The average percent NOx reduction from the test data was 84%.[15] Again, this data indicates that SCR is technically feasible for lean-burn engines. Instead, this data shows that SCR works to significantly reduce NOx from lean-burn engines. This test data was conducted from 1986 to 1993.[16] After 1993, EPA noted that the VCAPCD database did not include test data for lean-burn engines with SCR, but EPA also noted that several engines were replaced with electric motors and that a 1998 paper indicated that

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[6] *See* U.S. EPA, Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques, EPA-457/R-00-001, September 2000, *available at:* https://nepis.epa.gov/Exe/ZyPDF.cgi/P100V343.PDF?Dockey=P100V343.PDF ("EPA 2000 Update").
[7] March 6, 2020 Report at 35; EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-13.
[8] March 6, 2020 Report at 36-40.
[9] EPA 2000 Update at 4-14.
[10] *Id.*
[11] *Id.*
[12] *Id.*
[13] *Id.*
[14] *Id.*
[15] *Id.*
[16] *Id.*

VCAPCD's more stringent NOx limits adopted in 1993 were intended to encourage electrification of engines.[17]

EPA's 2000 Update also cited to information from vendors of SCR systems, indicating that SCRs on lean-burn engines since 1993 have been designed to achieve 80-95% control and citing to a design outlet NOx emissions levels for three lean-burn engines at one natural gas pipeline compressor facility of less than 30 ppmv. Again, that information indicates that SCR continued to be applied to lean-burn engines, including those used at compressor stations.

Also, EPA's 2000 Update discussed test summary data for three 3,130 bhp 4-stroke lean-burn engines equipped with SCR systems that were believed to be urea-based.[18] These engines were at a liquid fuel pipeline pumping station and operated at variable loads and variable speeds, "depending on the quantity, pressure, and density of the fuel being pumped."[19] EPA stated, "[t]he SCR system utilizes a feedforward system based on engine load and speed and on exhaust temperature." According to EPA, the engines achieved their required NOx emission limit (15 ppmv or about 0.2 g/bhp-hr) during all testing with NOx emission ranging between 0.11 grams per brake horsepower per hour (g/bhp-hr) and 0.21 g/bhp-hr.[20]

EPA's 2000 Update also discussed a plot of CEM data over a 10 minute period from a heavy-duty diesel truck engine equipped with a feedforward urea SCR system. According to EPA:

> During this period, the engine varied from a speed of about 700 rotations per minute (rpm) at idle to about 2,300 rpm, with load varying concurrently from nearly 0 foot-pounds (ft-lbs) to about 800 ft-lbs. Inlet NOX concentrations varied closely with load, ranging from a less than 10 ppmv up to over 150 ppmv. Outlet NOX concentrations remained relatively stable, varying from nearly 0 ppmv up to about 20 ppmv.[21]

While this CEM data is from a diesel engine, this data shows how a feedforward urea system can address issues of variable NOx emissions due to variable loads and engines speeds – regardless of whether coming from a diesel-fired or gas-fired engine.

EPA further stated:

> Vendors of SCR systems indicate that the feedforward controls on modern systems provide for excellent NOX control in load-following applications. One representative indicated that the advance in technology has been driven by the interest of diesel engine manufacturers, working with catalyst vendors, in developing urea SCR for on-road vehicles. Such vehicles exhibit varying load by nature. [Fn omitted]. Another source also stressed that the PEMS feedforward system, with optional CEMS feedback system, has been advanced by a strong research and development effort. This vendor

[17] *Id.* at 4-15.
[18] EPA 2000 Update at 4-15.
[19] *Id.*
[20] *Id.*
[21] *Id.*

> has supplied such SCR systems for a variety of applications, including stationary IC engines, ship engines, railroad engines, and diesel truck engines. [Fn omitted].[22]

In a more recent example of SCR being applied to two-stroke lean-burn engines, such engines at a power generating facility in Utah were successfully retrofit with SCR systems. Specifically, a Power Engineering article from 2006 discusses the retrofit of SCR systems along with catalytic convertors at lean burn engines at a Springville Utilities power station in Utah.[23] These engines burned 90% natural gas and 10% diesel. The article discusses one of the main problems using a catalyst on a two-stroke engine is the poisoning of the catalyst by the engine lubricant and states that the catalyst selected (manufactured by Miratech Corporation) was "designed to be durable and overcomes this problem."[24] While these units are used to generate electricity, this is still a relevant example of SCR being applied to two-stroke lean-burn engines. It is not known what the age of the two-stroke lean-burn engines that were retrofitted with SCR at the Springville Utilities power station in Utah. It appears that the power station being referred to is the Whitehead Power Plant, which (according to the Springville City website) was built in 1985 and was powered by Enterprise R4-V16 engines and EMD 645 engines.[25]

As another more recent example, a demonstration project was conducted at the Orange County Sanitation District's Central Power Generating Station, which is fueled by 95% landfill digester gas and 5% natural gas.[26] A demonstration project done at one Cooper Bessemer LSBV-12-SGC (a 3,471 hp lean-burn engine that drives a 2.5 MW generator) found that 78-86% NOx reduction could be achieved.[27]

SCR was also installed at the Bio Energy Washington landfill-gas dual-fuel power plant at which there are 18 dual-fuel 350 kW engine generators fueled by landfill gas and diesel.[28] This is a power plant located at the Cedar Hills gas processing facility in Washington.[29] An interesting fact about this application is that each SCR plus oxidation catalyst system treats the exhaust from 6 engines. Thus, only three SCR systems were required for 18 engines,[30] an approach that could greatly reduce the capital cost of NOx reduction and also address space constraints for SCR installation.

While we realize that space constraints can be an issue for SCR retrofits, this is something that has been dealt with on numerous instances for SCR retrofits for numerous industrial facilities. A concern about lack of space for an SCR should not be a reason to discount an SCR as not technically feasible without consultations with vendors about options for SCR locations. For example, the Manufacturers of

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[22] *Id.* at 4-15 to 4-16.
[23] *See* "Emissions Control for Huge Two-Stroke Engines: It Can Work, Power Engineering, 2/3/06, available at https://www.power-eng.com/2006/02/03/emissions-control-for-huge-two-stroke-engines-it-can-work/#gref.
[24] *Id.*
[25] *See* https://www.springville.org/power/about/.
[26] *See* Institute of Clean Air Companies, NJ DEP/ICAC Technology Seminar, November 24, 2014, at Slide 26.
[27] *Id*. at Slide 31. *See also* Johnson Matthey Application fact sheet 1304 for Orange County Sanitation District, available at https://www.jmsec.com/references/application-fact-sheets/?L=0.
[28] *See* Institute of Clean Air Companies, NJ DEP/ICAC Technology Seminar, November 24, 2014, at Slide 24.
[29] *Id.* at 21.
[30] *Id.* at Slide 24.

Emission Controls Association (MECA) describes situations where SCR systems have been installed in place of the existing exhaust muffler on the roof of buildings housing a lean-burn engine.[31]

In terms of SCR applications on lean-burn engines in the EPA's RACT/BACT/LAER Clearinghouse, we found several examples. The table below lists those RBLC entries that we found, which was not necessarily an exhaustive search.

EPA RACT/BACT/LAER Clearinghouse Entries for Lean-burn Engines with SCR

RBLC ID Number	Company Name	Permit Date	Weblink
MI-0440	MICHIGAN STATE UNIVERSITY	5/22/2019	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.PollutantInfo&Facility_ID=28704&Process_ID=113037&Pollutant_ID=149&Per_Control_Equipment_Id=166066
CA-1240	GOLD COAST PACKING	3/17/2017	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.PollutantInfo&Facility_ID=28389&Process_ID=111763&Pollutant_ID=149&Per_Control_Equipment_Id=161706
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	3/31/2016	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=28279&PROCESS_ID=111490
KS-0035	TRADEWIND ENERGY, INC.	1/24/2014	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=28362&PROCESS_ID=111715 and https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.PollutantInfo&Facility_ID=28362&Process_ID=111715&Pollutant_ID=149&Per_Control_Equipment_Id=161501
TX-0692	SOUTH TEXAS ELECTRIC COOPERATIVE, INC.	12/20/2013	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.PollutantInfo&Facility_ID=27823&Process_ID=109804&Pollutant_ID=149&Per_Control_Equipment_Id=156478
TX-0663	ETC TEXAS PIPELINE, LTD.	5/25/2012	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.PollutantInfo&Facility_ID=27718&Process_ID=109572&Pollutant_ID=149&Per_Control_Equipment_Id=155758
PA-0303	NATL FUEL GAS SUPPLY CORP	2/2/2012	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=28009&PROCESS_ID=110380
CA-0959	NEO CALIFORNIA POWER	4/9/2001	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.PollutantInfo&Facility_ID=25194&Process_ID=99462&Pollutant_ID=149&Per_Control_Equipment_Id=125492

In addition to these specific examples of SCR applications, a 2011 report from the state of Delaware highlights many examples of commercially available retrofit NOx controls for engines and turbines used in gas compressor prime mover service, including SCR.[32] Several of the SCR systems were specifically

[31] Written Statement of the Manufacturers of Emission Controls Association on the San Joaquin Valley Unified Air Pollution Control District's Proposed Amendments to Rule 4702 (August 2, 2011), *available at:* http://www.meca.org/galleries/files/MECA_SJV_Rule_4702_testimony_080211.pdf.

[32] *See* Background Information Oil and Gas Sector Significant Sources of NOx Emissions, *available online at*: https://fossil.energy.gov/ng_regulation/sites/default/files/programs/gasregulation/authorizations/2011/applications/exhibits_11-161-LNG/36_DE_Nox.pdf.

advertised as being applicable to lean-burn natural gas fired engines utilized for gas compression (e.g., CleanAir Systems, Johnson Matthey, Miratech Corporation, Clean Air Power, etc.).[33] We highlighted some of these vendors in our March 2020 report, and pointed out how catalysts have been developed to operate over a wide range of temperatures.[34] Some of the information provided in the Delaware report included specific announcements for orders and installations at lean-burn natural gas compressor engines and / or at natural gas midstream sources (e.g., installations on large lean-burn natural gas compressor engines at gas storage sites in Texas and Mississippi).[35] The Delaware report discusses some of the SCR systems being formulated for operation at a wide range of temperatures, allowing for NOx control over a wide range of engine operation.[36] More generally, the Delaware Report dispels several technical issues specific to two-stroke lean-burn SCR retrofits, including the availability of: (1) modern controls and communication technologies to help overcome potential issues with remotely manned units; (2) catalysts that are effective over wide temperature ranges that are reflective of a wider range in engine operating loads (noting that SCR systems "have been installed on EGUs that start and stop on a daily basis, and change loads across a wider range while on line to balance electric generation to electric demand"); and (3) the ability to closely regulate fuel, air, and reagent flow to ensure proper SCR function over a broad range of operating condition.[37]

Targa's February 2020 Regional Haze Four-Factor Analysis Addendum stated the following in response to NMED's request for the "historical precedent that installation of SACR on two-stroke lean-burn (@SLB) engines can result in significant technical complications, require deration of engines, and unreliable operation post-retrofit:"

> Selective catalytic reduction technology has not been applied successfully to 2SLB engines. After researching SCR controls on 2SLB engines, the EPA document titled "Technical Issues Related to the Potential Use of Selective Catalytic Reduction (SCR) to Reduce NOx Emissions from Natural Gas-Fired Lean Burn Engines" is the only document found with information on the application of SCR's on 2SLB engines. This documentation shows that many units did not perform properly after SCR was installed. Targa was unable to find any historical installation of SCR on 2SLB engines in the RLBC tables. The only proven technology to control NOX for 2SLB engines is Clean Burn Technology. This is also the technology recommended by the engine control vendor to control NOX for the units at Targa's three gas plants.[38]

It must first be pointed out that the document that Targa referred to as an "EPA document" is a 1998 document prepared for the Gas Research Institute. Second, the document referred to is now twenty-two years old. We provided one example of SCR being successfully retrofit to lean-burn engines at the Springville Utilities Power Station in Utah. Further, the 2011 Delaware reported discussed above highlights several SCR vendors with a focus on lean-burn engines, including two-stroke lean-burn

[33] *Id.* at PDF pp. 29-32.
[34] March 6, 2020 Report at 34. *See also* https://matthey.com/en/products-and-services/emission-control-technologies/mobile-emissionscontrol/selective-catalytic-reaction, https://www.miratechcorp.com/products/cbl/, and http://intermountainelectronics.com/uploads/media/Media_633929646982817973.pdf.
[35] *Id.* at PDF p. 31.
[36] *Id.* at PDF p. 30. (Johnson Matthey).
[37] *Id.* at PDF p. 35.
[38] February 2020 Regional Haze Four-Factor Analysis Addendum, Targa Midstream Services LLC, at pdf page 7.

engines. With respect to the RLBC not identifying any two-stroke engines using SCR, the RBLC entries that we found showing SCR being required on lean-burn engines generally do not specify whether the engines are two-stroke or four-stroke.

In summary, the information provided herein shows that SCR is considered a demonstrated technology that can be applied to lean-burn engines. The information presented above shows examples of SCR being applied to Cooper-Bessemer and Clark lean-burn engines. including two-stroke lean-burn engines. The reports cited above show application of SCR to natural gas-fired lean-burn engines used in the oil and gas industry starting in the 1980's to 1990's, and the RBLC data show SCR being required on lean-burn engines in more recent years including those used in the oil and gas industry. While application of SCR to lean-burn engines used in the oil and gas industry may not be commonplace, one cannot say it has not been required or implemented on lean-burn natural gas-fired engines used in the natural gas industry. Further, the fact that SCR has been retrofit and installed on lean-burn engines used in electricity production is still relevant information. Because most of those lean-burn engines operate as peaking or peak shaving power plants, the lean-burn engine load will vary greatly, more in line with how a compressor engine would operate. Thus, the use of SCR at natural gas-fired power generating lean-burn engines provides further support of the feasibility of SCR for lean-burn engines used in the oil and gas industry.

We understand that the age of the lean-burn engines for which NMED has requested reasonable progress analyses are quite old. Our review based on age of engines reported in permits for the New Mexico facilities shows that the age range of the lean-burn engines for which New Mexico has targeted for reasonable progress controls ranges from 39 years to as high as 72 years. Most of the engines were manufactured before the 1970 Clean Air Act was enacted. It appears that in most cases, the companies have not proposed any NOx controls for these older lean-burn engines in their reasonable progress analyses, claiming that SCR is not feasible and that Clean Burn (i.e., low emissions combustions) is too costly to retrofit. Given the age of these engines, consideration should be given to the control of replacing the engines with new engines with state-of-the-art low NOx emission control, or replacing the engines with electric engines powered off the grid which would reduce emissions of NOx (and all other pollutants from the engines) down to zero. As discussed in our March 6, 2020 Report, replacement of engines with electric motors can be quite cost effective.[39]

[39] March 6, 2020 Report at 41-46.

*** Coalition to Protect America's National Parks * Diné C.A.R.E. * Earthjustice * National Parks Conservation Association * San Juan Citizens Alliance * Sierra Club * Western Environmental Law Center ***

May 29, 2020

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Re: Petition to EPA for Reconsideration of Regional Haze Final Guidance

Dear Ms. Ely:

We applaud the New Mexico Environment Department for developing a Regional Haze Rule while welcoming robust public engagement. By this letter, we are forwarding to you a copy of a Petition for Reconsideration submitted to the United States Environmental Protection Agency on May 8, 2020. This petition requests that EPA reconsider its "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," issued August 20, 2019 (Final Haze Guidance).

The regional haze program under the Clean Air Act sets as its goal the restoration of natural visibility conditions in national parks and other Class I areas. States are now preparing implementation plans for the second round of planning, which are critical to achieving haze reduction goals. As detailed in the Petition for Reconsideration, however, EPA's Final Haze Guidance undercuts progress on regional haze. Instead, states must follow statutory and regulatory directives as they prepare haze plans:

- States must select sources for analysis in compliance with 40 C.F.R. § 51.308(f)(3)(ii)(A). States must comprehensively identify sources of human-caused visibility-impairing emissions across source categories and develop technically sound and transparent information on the process by which sources are selected for review and four factor analyses. States cannot arbitrarily defer some sources to another implementation period.
- States have only limited discretion to decide which sources they consider for reasonable progress.

- State plans must result in reasonable progress and will be found deficient where they fail to require emission reductions that collectively make reasonable progress towards natural visibility at every Class I area in each and every planning period; no backsliding is permitted.
- States cannot arbitrarily circumvent a four-factor analysis for sources that intend to retire.
- States cannot consider being under the uniform rate of progress when selecting sources for a four-factor analysis. The glidepath is not a safe harbor; rather a state must take measures necessary to make progress towards natural visibility by reducing visibility-impairing pollution.
- Previous installation of certain types of controls does not excuse a state from considering more stringent levels of control.
- States should ensure that modeled emissions are tied to enforceable limits for sources with appropriate averaging times that reflect year-round abilities of existing controls or operation.
- States must include both dominant and non-dominant pollutants in their analyses of controls.
- States cannot eliminate VOC and ammonia emissions from consideration.
- Light extinction thresholds should be tailored to Class I areas and low enough to bring in most sources of visibility-impairing pollution.
- States should include all visibility-impairing pollutants when calculating a source's annual emissions.
- States must use methods permitted by statute and regulation to identify its sources that potentially affect visibility at Class I areas in other states, not merely any "reasonable method."
- States must consider cumulative impacts of sources or groups of sources to all affected Class I areas.
- States must prioritize emissions within their borders to achieve reasonable progress.
- States should identify and consider the best available emission control measures in the four-factor reasonable progress analysis.
- States must adhere to the accounting principles of the Control Cost Manual and should compile and make publicly available the documentation for generic cost estimates.
- States should analyze the climate and environmental justice impacts of measures to achieve reasonable progress.
- States cannot allow sources to discontinue the use of currently operating controls.
- States should use regional scale modeling to support their regional haze plans.
- If a state's reasonable progress goal is above the uniform rate of progress, the state's "robust demonstration" must include a consideration of specific items identified by EPA.
- States must submit to EPA the emission inventory used in a regional haze SIP.
- States must ensure that Federal Land Managers' opinions and concerns are made transparent to the public, considered by the state and addressed in the haze plan.
- Decisions on which controls to require as part of the long-term strategy cannot merely ratify past determinations.

- EPA must ensure that long-term strategies include appropriate measures to prevent future as well as remedy existing impairment of visibility.

Weakening the above directives would contradict New Mexico's guiding principles in developing a statewide Regional Haze Rule which ensures the health and safety of the state's residents, and the visibility and cleanliness of the air in and around Class 1 airsheds. For the New Mexico Environment Department to be able to adequately and legitimately shape as strong a Regional Haze Rule as possible, consistent federal guidance which complies with the Clean Air Act and Regional Haze Rule is necessary.

One of the directives above is that "States cannot arbitrarily circumvent a four-factor analysis for sources that intend to retire." This is of particular relevance in New Mexico, where the San Juan Generating Station in the northwest corner of the state has not yet submitted a four-factor analysis for controls. The station is under no federally enforceable retirement directive, and assumption of ownership of the facility is presumed to go to Enchant Energy – the station must submit a plan to the state of its analysis of implementing pollution controls at its facilities, as it is the greatest emitter of haze-causing pollutants in the Four Corners Region.

The aggressive expansion of oil and gas development on public lands throughout New Mexico—in particular, the Permian and San Juan Basins—has resulted in repeated and egregious occurrences of exceedance in allowable concentrations of haze-causing, and human-health degrading, air pollutants. State rulemaking processes are aiming to reduce concentrations of some of these air pollutants near energy hotspots where they disproportionately damage human health, the environment, and the iconic landscapes connected with nearby communities. Methane, ozone, and haze-causing pollutant sources are currently undergoing review as NMED develops methods for reducing pollution in the face of unchecked development and associated ecological degradation. These rulemaking processes and the regional haze SIP development process present an opportunity to ensure that air quality protections in New Mexico are mutually reinforcing, and thus stronger overall. EPA's guidance should not undermine these opportunities.

Not only are these regulatory processes occurring along similar timelines, with regulations often encompassing overlapping parts of the industrial/emissions process, the pollutants themselves are often precursors to other toxins—at the ground level, ozone is created in harmful concentrations by a chemical reaction between oxides of nitrogen (NOx) and volatile organic compounds (VOC) in the presence of heat and sunlight. The EPA's guidance must not excuse VOCs from regulation under the regional haze rule. Asthma and other illnesses linked to poor air quality disproportionately impact communities in and around the Permian and San Juan Basin regions where drilling has increased exponentially over the past several years – particulate matter, methane, ozone, VOCs, NOx, SOCs, and others greatly compromise these communities' overall public health.[1][2][3]

[1] http://www.stateoftheair.org/city-rankings/states/new-mexico/eddy.html
[2] https://www.hcn.org/issues/51.10/public-health-the-hidden-consequences-of-new-mexicos-latest-oil-boom
[3] https://nmlegis.gov/handouts/IAC%20100417%20Item%208%20Drilling%20on%20and%20Near%20Sacred%20Sites%203.pdf

The crucial need to curtail emissions from both operational and abandoned oil and gas wells and infrastructure, and improve air quality across the state, is particularly pressing in light of the COVID-19 public health crisis. A report, published on the preprint health services platform Medrxiv.com in early April, found that long-term exposure to particulate matter is positively correlated with the severity of COVID-19 cases contracted.[4] The guidance provided by the EPA for states to fulfill the Regional Haze Rule must underscore the importance of strong air pollution controls to protect human health and the environment, now and after the crisis.

With states moving forward on haze plans, state officials should be aware of deficiencies in the Final Haze Guidance, and should ensure that state plans still reinforce relevant state rulemakings and guiding principles and comply with the Clean Air Act and the Regional Haze Rule.

Thank you for your attention to our Petition for Reconsideration. We are available to continue discussing second round regional haze issues, including those raised by the Petition, at your convenience.

Sincerely,

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[4] https://www.medrxiv.org/search/particulate%252Bmatter%252Bcovid

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May 8, 2020

Via Federal Express and Email

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Re: Petition for Reconsideration of Guidance on Regional Haze State Implementation Plans for the Second Implementation Period

Dear Administrator Wheeler:

I. Introduction

National Parks Conservation Association, Sierra Club, Natural Resources Defense Council, Western Environmental Law Center, Appalachian Mountain Club, Coalition to Protect America's National Parks, and Earthjustice (hereinafter "Conservation Organizations") hereby petition[1] the Administrator of the United States Environmental Protection Agency ("EPA") to reconsider the entitled "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" (hereinafter "Final Guidance" or "Guidance")[2] and replace it with

[1] This Petition is filed pursuant to section 4(d) of the Administrative Procedure Act ("APA"), 5 U.S.C. § 553(e), and, to the extent it may be applicable and relevant, section 307(d)(7)(B) of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B).

[2] EPA issued the Final Guidance on August 20, 2019 via Memorandum from Peter Tsirigotis, Director at EPA Office of Air Quality Planning and Standards to EPA Air Division Directors.

guidance that comports with the Clean Air Act ("CAA") and the Regional Haze Rule, and aids states in making progress towards achieving the national goal of natural visibility conditions at all Class I areas.[3] The Final Guidance is a significant departure from the Draft Guidance[4] issued in 2016 for the second planning period and contains provisions that are expressly at odds with the Clean Air Act and Regional Haze Rule. The table below summarizes how key provisions of the Final Guidance should be revised to comply with the requirements of the applicable statutes and regulations.

The Guidance unlawfully directs states on how they may exclude certain emission sources from four-factor consideration and delay or altogether avoid reducing emissions necessary to meet Congress's mandate that the states make reasonable progress towards the national goal of restoring natural visibility to Class I area national parks and wilderness areas. 42 U.S.C. § 7491(b)(2). The Guidance not only conflicts with the text and purpose of the Clean Air Act and the Regional Haze Rule itself, but it conflicts with EPA's 2016 Draft Guidance by arbitrarily constraining EPA review authority, diminishing the science of regional haze, and recasting technical and analytical requirements for State Implementation Plans ("SIPs"). Implementation of the Final Guidance will result in inconsistencies between SIPs, create arbitrary exceptions allowing states to avoid controlling emission sources, impede progress toward the national goal of a restoring natural visibility, and may actually degrade visibility at some Class I areas.

Section of the Petition	Summary of Issue	Applicable Regional Haze Rule or other Regulations[5]
III.A.	States must comprehensively identify sources of human-caused visibility-impairing emissions across source categories and cannot arbitrarily defer some sources to another implementation period.	Section 51.308(f)(3)(ii) of the Regional Haze Rule and Clean Air Act section 169A(b)
III.B.	States have only limited discretion to decide which sources they consider for reasonable progress. SIPs will be found deficient where they fail to require emission reductions that collectively make reasonable progress towards natural visibility at all Class I areas in each planning period; no backsliding is permitted.	82 Fed. Reg. at 3,088 and sections 51.308(f)(2)(i), 51.308(f)(3)(ii)(A), 51.308(f)(3)(ii)(B)
III.C.	States cannot arbitrarily circumvent a four-factor analysis for sources that intend to retire.	Sections 51.308(f)(2)(i), 51.308(f)(2)(iv)(C)

[3] 42 U.S.C. §§ 7491, 7492; 82 Fed. Reg. 3078 (Jan. 10, 2017); 71 Fed. Reg. 60,612 (Oct.13, 2006); 70 Fed. Reg. 39,104 (July 6, 2005); 64 Fed. Reg. 35,714 (July 1, 1999).

[4] Draft Guidance on Progress Tracking Metrics, Long-term strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, (hereinafter "Draft Guidance") 81 Fed. Reg. 44,608 (July 8, 2016).

[5] Clean Air Act section 110(k)(5) provides EPA the authority to review a SIP and assess the adequacy of that SIP. Therefore any aspect of this guidance that interferes with that authority is in conflict.

III.D.	States cannot consider being under the uniform rate of progress ("URP") when selecting sources for a four-factor analysis. The glidepath is not a safe harbor; rather a state must take measures necessary to make progress towards natural visibility at any Class I areas its emissions affect.	82 Fed. Reg. at 3,093
III.E.	Previous installation of certain types of controls does not excuse a state from considering more stringent levels of control.	Section 51.308(f)(2)(iv)(D)
III.G.	States must include both "dominant" and "non-dominant" pollutants in their analyses of controls.	82 Fed. Reg. at 3,088 and sections 51.308(f)(3)(ii)(A), 51.308(f)(3)(ii)((B), 51.308(f)(2)(i)
III.H.	States cannot eliminate volatile organic compounds ("VOCs") and ammonia emissions from consideration.	82 Fed. Reg. at 3,088 and sections 51.308(f)(3)(ii)(A), 51.308(f)(3)(ii)(B), 51.308(f)(2)(i)
IV.A.	States must use methods permitted by statute and regulation to identify its sources that potentially affect visibility at Class I areas in other states, not merely any "reasonable method."	82 Fed. Reg. at 3,094 and sections 51.308(f)(2)(i), 51.308(d)(3)(iv)
IV.B.	States must consider cumulative impacts of sources or groups of sources to all affected Class I areas.	Section 51.308(f)(2)(i)
V.A.	States must prioritize emissions within their borders to achieve reasonable progress.	Sections 51.308(f)(1)(vi)(B), 51.308(f)(2)(iv)(D), and Clean Air Act section 169A(b)
VI.B.	States must adhere to the accounting principles of the Control Cost Manual and should compile and make publicly available the documentation for generic cost estimates.	Section 51.308(f)(2)(i)
VII.A.	States cannot allow sources to discontinue the use of currently operating controls.	Section 51.308(f)(2) and Clean Air Act section 169A(b)(2)
VIII	States should use regional scale modeling to support their regional haze SIPs.	Section 51.308(f)(3)(ii)(A), Appendix W to Part 51
IX.A.	If a state's reasonable progress goal ("RPG") is above the URP, the state's "robust demonstration" must include a consideration of specific items identified by EPA.	Section 51.308(f)(3)(ii)
X.A.	States must submit to EPA the emission inventory used in a regional haze SIP.	Section 51.308(f)(2)(iii), Clean Air Act section

		110(k)(5), and EPA's Emission Inventory Guidance[6]
X.B.	States must ensure that Federal Land Managers' ("FLMs") opinions and concerns are made transparent to the public, considered by the state and addressed in the SIP.	Sections 51.308(i), 51.308(f)(4) and Clean Air Act sections 169A(a) and (d)
XI.B.	Decisions on which controls to require as part of the long-term strategy cannot merely ratify past determinations.	Section 51.308(f)(2)(i)
XI.C.	EPA must ensure that long-term strategies include appropriate measures to prevent future as well as remedy existing impairment of visibility.	Clean Air Act section 169A(a)

This Petition seeks reconsideration and substantial revision of the Final Guidance so that the Guidance will direct states to deliver on the statutory objective of preventing future and remedying existing Class I area visibility impairment that results from human-caused pollution. As issued, the Final Guidance conflicts with this statutory objective, previous rulemaking and guidance; misdirects states as to how they can go about complying with their legal obligations to make reasonable progress towards restoring natural visibility to protected public lands; and otherwise fails to set expectations that comport with legal requirements for the second planning period.

In addition to the provisions noted in the table above, the Conservation Organizations incorporate several recommendations from their Comments on EPA's Draft Guidance[7] and request that EPA reconsider and revise the Final Guidance to direct states with regard to the following issues:

- States should ensure that modeled emissions are tied to enforceable limits for sources with appropriate averaging times that reflect year-round abilities of existing controls or operation.
- Light extinction thresholds should be tailored to Class I areas and low enough to bring in most sources of visibility-impairing pollution.
- States should include all visibility-impairing pollutants when calculating a source's annual emissions.
- States should identify and consider the best available emission control measures in the four-factor reasonable progress analysis.

[6] EPA, Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations (May 2017), https://www.epa.gov/sites/production/files/2017-07/documents/ei_guidance_may_2017_final_rev.pdf.
[7] Conservation Organizations incorporate by reference their full Comments on the 2016 proposed Draft Guidance.

- States should analyze the climate and environmental justice impacts of measures to achieve reasonable progress.

The gains made in the first regional haze planning period established a critical, if delayed, foundation for our national parks and wilderness areas to make progress towards the natural visibility which they and their visitors and neighboring communities are due. The Final Guidance not only hinders future gains but in some cases actually jeopardizes the gains made in the first planning period. Conservation Organizations urge EPA to reconsider its Final Guidance and instead issue a revised guidance that directs states to fulfill regulatory requirements for reasonable progress in the second planning period to help attain clearer skies at America's prized national parks and wildernesses.

II. SIP development steps

As EPA states in the Final Guidance, the key steps to developing a regional haze SIP start with identifying the twenty percent most anthropogenically impaired days and the twenty percent clearest days and determining baseline, current, and natural visibility conditions for each Class I area within the state, and then determining which Class I area(s) in other states may be affected by the state's own emissions.[8] States must then screen sources and conduct a four-factor analysis of which controls are required before establishing reasonable progress goals.[9] Once a state has determined the reasonable progress measures to require at specific sources, the state must quantify the "reasonable progress goal"—i.e., the visibility improvement that will result from implementing the controls merited by a four-factor analysis.[10] Additional steps include regional scale modeling of the long-term strategy to set the RPGs for 2028 and progress, degradation, and URP glidepath checks.[11]

Some of the most problematic provisions of the Final Guidance, which are contrary to several requirements of the Regional Haze Rule and Clean Air Act, involve the selection of sources for analysis. After discussing these provisions, this Petition discusses the determination of affected Class I areas in other states, ambient data analysis, the characterization of factors for emission control measures, decisions on what control measures are necessary to make reasonable progress, regional scale modeling of the long-term strategy to set the RPGs for 2028, progress, degradation, and URP glidepath checks, and additional requirements for regional haze SIPs. After addressing how these various provisions of the Guidance are contrary to the regulatory requirements, the Petition provides several overarching recommendations that EPA should consider when revising the Guidance, including advising states that in order for a SIP to be approvable it must result in measures to reduce visibility impairing pollution beyond those required from the past planning period and reflective of an adequate reasonable progress analysis.

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[8] Final Guidance at 5.
[9] *Id.*
[10] *Id*.
[11] *Id*. at 5-6.

III. Selection of sources for analysis

A. Selection of sources under section 51.308(f)(3)(ii)(A).

In the Final Guidance, EPA presents a statement at the beginning of the section II.B.3 that is in conflict with the Regional Haze Rule's requirements:

> A key flexibility of the regional haze program is that a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures. . . . Accordingly, it is reasonable and permissible for a state to distribute its own analytical work, and the compliance expenditures of source owners, over time by addressing some sources in the second implementation period and other sources in later periods.[12]

This statement by EPA is contrary to the requirements in section 51.308(f)(3)(ii) of the Regional Haze Rule and section 169A(b) of the Clean Air Act.

In a footnote, EPA indicates that "analysis of control measures" refers to an analysis of what emission control measures for a particular source are necessary in order to make reasonable progress and must include consideration of the four statutory factors and consideration of the five additional factors listed in 40 C.F.R. § 51.308(f)(2)(iv).[13] This important requirement of how sources should be selected by states for analyses is presented as if it were a secondary consideration. In other words, EPA's Guidance now advises states that they can arbitrarily delay the selection of sources for evaluation, or exclude certain sources as noted *infra*, and thereby "distribute [their] analytical work" and the "compliance expenditures of source owners" as if it is a stand-alone, top-level decision that states can make, divorced of the need to apply the four statutory factors and the five additional factors to actually make reasonable progress.

If a state were to arbitrarily "distribute its own analytical work, and the compliance expenditures of source owners, over time"[14] as the guidance provides, it would not be able to address section 51.308(f)(3)(ii)(B), which requires:

> If a State contains sources which are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area in another State for which a demonstration by the other State is required under (f)(3)(ii)(A), the State must demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to

[12] *Id.* at 9.
[13] *Id.* at 9 n.22.
[14] *Id.* at 9.

> include in its own long-term strategy. The State must provide a robust demonstration, including documenting the criteria used to determine which sources or groups or sources were evaluated and how the four factors required by paragraph (f)(2)(i) were taken into consideration in selecting the measures for inclusion in its long-term strategy.

A state that arbitrarily excludes sources from consideration cannot determine if it actually has "sources which are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area." To satisfy that requirement, a state must first have a reasonable understanding of the emissions from all of its sources and it must have a reasoned methodology for excluding sources from a four-factor analysis (e.g., those sources are inconsequential or do not have cost-effective control options). Similarly, if a state, which arbitrarily excludes sources from evaluation, has a RPG that is above the URP, it cannot satisfy section 51.308(f)(3)(ii)(A)[15], which requires that it demonstrate "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the long-term strategy." In contrast, not only was this advice absent from EPA's Draft Guidance, the Draft Guidance provided detailed, valid information on source selection.[16]

Additionally, as mentioned *infra* section IV.A, the Final Guidance also arbitrarily allows states to decide whether they contribute to out-of-state Class I areas by claiming states can use any reasonable method for quantifying the impacts of its own emissions on out-of-state Class I areas.[17] The Final Guidance also allows a state to disregard its impacts on an out-of-state Class I area that a neighboring state may identify as being affected by emissions from the state developing the long-term strategy.[18] By allowing states to arbitrarily make these determinations, EPA is attempting to slice the program into inconsequential bits and pieces that set the

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[15] EPA noted in the 2017 Regional Haze Rule revision:

> [I]n a situation where the RPG for the most impaired days is set above the glidepath, a contributing state must make the same demonstration with respect to its own long-term strategy that is required of the state containing the Class I area, namely that there are no other measures needed to provide for reasonable progress. The intent of this proposal was to ensure that states perform rigorous analyses, and adopt measures necessary for reasonable progress, with respect to Class I areas that their sources contribute to, regardless of whether such areas are located within their borders.

82 Fed. Reg. at 3099. *See also* 81 Fed. Reg. 66,331, 66,631 (Sept. 27, 2016) ("[A]n evaluation of the four statutory factors is required . . . regardless of the Class I area's position on the glidepath. . . . [T]he URP does not establish a 'safe harbor' for the state in setting its progress goals."); 81 Fed. Reg. 295, 326 (Jan. 5, 2016) ("[T]he uniform rate of progress is not a 'safe harbor' under the Regional Haze Rule"); EPA, Guidance for Setting Reasonable Progress Goals under the Regional Haze Program (hereinafter "RPGs Guidance") (June 2007) 4–1, https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/20070601_wehrum_reasonable_progress_goals_reghaze.pdf.

[16] Draft Guidance at 57-83.

[17] Final Guidance at 8.

[18] *Id.* at 9.

provisions of the Final Guidance against fulfilling the requirements of the Clean Air Act and Regional Haze Rule that compel a comprehensive "regional" approach to restoring visibility. EPA should strike the above-mentioned language discussing selection of sources under section 51.308(f)(3)(ii)(A) from the Final Guidance and restore the language from the Draft Guidance.

B. States have only limited discretion to decide which sources they consider for reasonable progress.

In Section II.B.3.d of the Final Guidance, EPA states, "[t]he source-selection step is intended to add flexibility and discretion to the state planning process – ultimately, the state decides which sources to consider for reasonable progress."[19] This blanket statement, written as if a state has unbounded discretion to determine which sources it evaluates under reasonable progress, is incorrect. A state cannot arbitrarily determine which sources it evaluates under the Regional Haze Rule's reasonable progress requirements. Ultimately, a state's source selection criteria is a part of its long-term strategy. As EPA indicated in the Regional Haze Rule revision, a state does not have discretion to arbitrarily exclude sources from a four-factor analysis. Specifically, EPA stated:

> [W]e expect states to exercise reasoned judgment when choosing which sources, groups of sources or source categories to analyze. Consistent with CAA section 169A(g)(1) and our action on the Texas SIP, a state's reasonable progress analysis must consider a meaningful set of sources and controls that impact visibility. If a state's analysis fails to do so, for example, by arbitrarily including costly controls at sources that do not meaningfully impact visibility or failing to include cost-effective controls at sources with significant visibility impacts, then the EPA has the authority to disapprove the state's unreasoned analysis and promulgate a [Federal Implementation Plans ("FIPs")]. [20]

A state with a RPG below the URP that followed this guidance and arbitrarily excluded sources from a four-factor analysis runs afoul of section 51.308(f)(3)(ii)(A), which requires a "robust demonstration" that "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the long-term strategy." If a state that followed this guidance had emission sources that potentially affect visibility at a Class I area in another state, it would similarly be unable to satisfy the same requirement found in section 51.308(f)(3)(ii)(B). EPA should reconsider this provision, and delete it from the Final Guidance.

C. States cannot arbitrarily circumvent a four-factor analysis for sources that intend to retire.

[19] Final Guidance at 20.
[20] 82 Fed. Reg. at 3088.

In Section II.B.3.d of the Final Guidance, EPA also states "[i]f a source is expected to close by December 31, 2028, under an enforceable requirement, a state may consider that to be sufficient reason to not select the source at the source selection step."[21] EPA goes on to extend this deadline by adding an indeterminate grace period: "The year 2028 is not a bright line for these considerations, so a state may be able to justify not selecting a source for analysis of control measures because there is an enforceable requirement for the source to cease operation by a date after 2028."[22] EPA further advises states that consideration of source retirement and replacement schedules required by Section 51.308(f)(2)(iv)(C) are automatically considered if a state decides to not subject sources which will retire by 2028 to a four-factor analysis.[23]

This is a departure from EPA's long-standing requirement in the regional haze program and is in conflict with basic requirements of the Regional Haze Rule. Remaining useful life is one of the four statutory factors that a state must consider when selecting the sources for which it will determine what control measures are necessary to make reasonable progress.[24]

The Clean Air Act does not define the phrase "remaining useful life." However, EPA, in regulations and guidance, has clarified the meaning of the phrase. EPA has consistently stated that the potential retirement of a facility can be used to shorten a source's remaining useful life only if the retirement is federally enforceable.[25] Thus, in order to affect the remaining useful life, a retirement commitment must be included in a pre-existing document that can be enforced in federal court, such as a consent decree entered by a federal court, or a state must incorporate the retirement date into its SIP. If a potential retirement is not federally enforceable, it cannot be relied upon to shorten the remaining useful life of a source.

EPA's 2007 Guidance on reasonable progress incorporates and refers to the best available retrofit technology ("BART") Guidelines,[26] which instruct states on how to calculate the remaining useful life of a source. EPA defines a source's "remaining useful life" as the difference between the date that controls would be installed and "the date the facility permanently stops

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[21] Final Guidance at 20.
[22] *Id.*
[23] *Id.* at 22.
[24] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) ("[A]n agency rule would be arbitrary and capricious if the agency has . . . entirely failed to consider an important aspect of the problem."); *Pub. Citizen v. Fed. Motor Carrier Safety Admin.*, 374 F.3d 1209, 1216 (D.C. Cir. 2004) ("A statutorily mandated factor, by definition, is an important aspect of any issue before an administrative agency, as it is for Congress in the first instance to define the appropriate scope of an agency's mission.").
[25] *E.g.*, 83 Fed. Reg. 62,204, 62,232 (Nov. 30, 2018) ("We are proposing to agree with Arkansas' cost analysis for dry scrubbers and switching to low sulfur coal for Independence Units 1 and 2, and with the state's decision to assume a 30-year capital cost recovery period in the cost analysis. It is appropriate to assume a 30-year capital cost recovery period in the cost analysis since Entergy's plans to cease coal combustion at the Independence facility are not state or federally-enforceable."); 83 Fed. Reg. 43,586, 43,604 (Aug. 27, 2018) (Considering the retirement of certain units where there was evidence that the units had actually been retired at the time of the rulemaking and that the plant had requested cancellation of its air permit).
[26] RPGs Guidance at 5-3. There is no conflict with the 2007 Guidance's interpretation of "remaining useful life" and the Final Guidance. *See* Final Guidance at 34.

operations."[27] If the remaining useful life affects the selection of controls, "this date should be assured by a federally- or State-enforceable restriction preventing further operation."[28] EPA discusses a situation where a source "intends to shut down a source by a given date, but wishes to retain the flexibility to continue operating beyond that date in the event."[29] In that instance, EPA instructs a state to include in its SIP the controls that would be required if the source continues to operate past the planned retirement date.[30] "The source would not be allowed to operate after the 5–year mark without such controls."[31]

Allowing states to avoid a four-factor analysis based on alleged intent to retire would render the other statutory factors meaningless and violate the requirements of the Regional Haze Rule.[32] Many states have already begun analyzing their sources to determine which should be brought forward for a four-factor analysis. Consequently, a source that retires by December 31, 2028 (or later), has at least eight years of potential emission reductions. Even considering this shortened remaining useful life, cost-effective controls, which often can be installed in months, can frequently be justified. For instance, a source could simply switch to a lower sulfur content coal or fuel oil, which would require little to no installation time and may be quite cost-effective. Despite EPA's advice, any source that demonstrably or potentially impacts visibility at a Class I area and would otherwise be subject to a four-factor analysis under section 51.308(f)(2)(i), regardless of its retirement date, must undergo a real analysis to determine if cost-effective controls are available.[33] EPA should revise the Final Guidance to reiterate that only enforceable retirements may alter the remaining useful life and otherwise require that states subject sources that intend to retire to a four-factor analysis if a state selects the source for analysis of emission control measures.

D. States cannot consider being under the URP when selecting sources for a four-factor analysis.

In Section II.B.3.e of the Final Guidance, EPA makes two flawed statements regarding a state's RPG that were not present in the Draft Guidance. First, EPA states "[t]he fact that visibility conditions in 2028 will be on or below the URP glidepath is not a sufficient basis by itself for a state to select no sources for analysis of control measures; however, the state may

[27] 40 C.F.R. pt. 51, App. Y § (IV)(D)(4)(k)(2).
[28] *Id.*
[29] *Id.* § (IV)(D)(4)(k)(3).
[30] *Id.*
[31] *Id.*
[32] The United States Court of Appeals for the Fifth Circuit recently found that EPA must consider statutory factors listed in a similar provision of the Clean Water Act when revising best available technology ("BAT") limits. *See Southwestern Elec. Power Co. v. EPA*, 920 F.3d 999, 1026-27 (5th Cir. 2019).
[33] EPA's draft guidance also allowed for states to forgo a four-factor analysis on sources secured by an enforceable commitment to retire by 2028. We disagree with that position for the reason expressed above. However, EPA tempered its reasoning in its draft guidance by stating that its position rested on the fact that due to the shortened second planning period (unlike future planning periods), there would be a shorter interval for states to install controls. Also, EPA did not state that states could extend source retirements beyond 2028 as it does in the final guidance.

consider this information when selecting sources."[34] EPA then cites to the 2017 Regional Haze Rule revisions; however, those citations make it absolutely clear that states cannot in fact follow this guidance:

> We disagree that the states should be able to reevaluate whether a control measure is necessary to make reasonable progress based on the RPGs. The CAA requires states to determine what emission limitations, compliance schedules and other measures are necessary to make reasonable progress by considering the four factors. The CAA does not provide that states may then reject some control measures already determined to be reasonable if, in the aggregate, the controls are projected to result in too much or too little progress. [35]

Consequently, states have no path available to them to "consider this information when selecting sources."

Similarly, EPA's later advice that "[r]ather, that fact [that a state's RPG is below the URP] would serve to demonstrate that, after a state has gone through its source selection and control measure analysis, it has no 'robust demonstration' obligation per 40 CFR 51.308(f)(3)(ii)(A) and/or (B)"[36] is potentially at odds with the Regional Haze Rule. In the above cited portion of the 2017 Regional Haze Rule revision, EPA actually stated, "if a state has reasonably selected a set of sources for analysis and has reasonably considered the four factors in determining what additional control measures are necessary to make reasonable progress, then the state's analytical obligations are complete if the resulting RPG for the most impaired days is below the URP line."[37] A state's "robust demonstration" obligation does not end because it has merely "gone through its source selection and control measure analysis." Rather, as EPA actually explained, the state must have "reasonably selected a set of sources for analysis and has reasonably considered the four factors in determining what additional control measures are necessary to make reasonable progress." [38] EPA must reconsider this provision, and delete it from the Final Guidance.

E. Previous installation of certain types of controls does not excuse a state from considering more stringent levels of control.

In section II.B.3.f of the Final Guidance, EPA discusses circumstances under which a state can choose not to select a source that has previously installed controls for a four-factor analysis.[39] Much of this information conflicts with previous guidance and the Regional Haze

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[34] Final Guidance at 22.
[35] 82 Fed. Reg. at 3093. *See also* 81 Fed. Reg. at 66,631; 81 Fed. Reg. at 326; RPGs Guidance at 4-1.
[36] Final Guidance at 22.
[37] 82 Fed. Reg. at 3093.
[38] *Id.*
[39] *Id.* In comparison to the blanket exemptions in EPA's Final Guidance, the Draft Guidance only considered exempting power plant units, "in certain limited situations," with "highly effective control technology within the 5 years prior to submission of the SIP, such as year-round operation of flue gas desulfurization (FGD) with an

Rule. First, EPA states, "[i]n general, if post-combustion controls were selected and installed fairly recently . . . to meet a [Clean Air Act] requirement, there will be only a low likelihood of a significant technological advancement that could provide further reasonable emission reductions having been made in the intervening period."[40] EPA presents no basis for making this conclusion.

There are many instances in which post-combustion controls have been installed in which those controls do not operate at peak efficiency. This includes controls that are not operated continuously, controls that were never designed to operate at peak efficiency (e.g., undersized sulfur dioxide ("SO_2") scrubber or selective catalytic reduction ("SCR") systems) and partially bypassed controls (e.g., SO_2 scrubber or SCR systems). In fact, EPA has made it a point in past actions to ensure that existing controls are examined to determine if they can be cost-effectively upgraded. For instance, the 2005 BART revision to the Regional Haze Rule devotes several paragraphs to specific potential scrubber upgrades it recommends be examined.[41]

EPA also demonstrated that scrubber upgrades to a number of coal-fired power plants utilizing outdated and inefficient scrubber systems were highly cost-effective, and could achieve removal efficiencies of ninety-five percent which is near the ninety-eight to ninety-nine percent removal efficiencies of newly-installed scrubber systems.[42] In fact, as EPA notes in its 2017 Regional Haze Rule revision, EPA disapproved Texas' four-factor analysis in part because "it did not include scrubber upgrades that would achieve highly cost-effective emission reductions that would lead to significant visibility improvements."[43] Consequently, EPA's blanket guidance that examination of potential upgrades to recently installed post-combustion controls is unlikely necessary is demonstrably false. Even if, considering the entire universe of potential post-combustion control upgrades, the vast majority cannot be cost-effectively upgraded to result in significant visibility benefits, which is unlikely, there is no justification in the Regional Haze Rule to skip an examination of the remaining units.

EPA goes on to present examples of pollutant-specific controls that have been installed due to a requirement outside of the regional haze program for which it "believes it may be reasonable for a state not to select a particular source for further analysis."[44] This list includes new source performance standard ("NSPS") controls installed since July 31, 2013; best available control technology ("BACT") or lowest achievable emission rate ("LAER") controls installed since July 31, 2013; power plants with FGD controls that meet the 2012 model attainment test systems ("MATS") standard; particulate matter ("PM") controls under National Emission

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effectiveness of at least 90 percent or year-round operation of selective catalytic reduction with an effectiveness of at least 90 percent." EPA specifically requested comment "on whether to include this additional screening mechanism and if so, then what criteria may be appropriate for its inclusion."

[40] *Id.*

[41] *See* 70 Fed. Reg. 39,103, 39,171 (July 6, 2005).

[42] *See* 81 Fed. Reg. at 305.

[43] *See* 82 Fed. Reg. at 3088.

[44] Final Guidance at 23.

Standards for Hazardous Air Pollutants ("NESHAP") since July 31, 2013; boilers that have installed an FGD or SCR system that operates year round and has a total efficiency of ninety percent; and any BART-eligible unit that has installed BART controls.[45] EPA reasons that due to their recent installation and the similarity of the requirements for those programs, it is unlikely that a four-factor analysis will result in additional cost-effective controls.[46] But, as EPA notes in its 2005 BART revision to the Regional Haze Rule, it reviewed some of these standards and concluded they may not be the most stringent available.[47] Furthermore, the 2017 revision to the Regional Haze Rule warned states that "we anticipate that a number of BART-eligible sources that installed only moderately effective controls (or no controls at all) *will need to be reassessed*. Under the 1999 [Regional Haze Rule and] 40 CFR 51.308(e)(5), BART-eligible sources are subject to the requirements of 40 CFR 51.308(d), which addresses regional haze SIP requirements for the first implementation period, in the same manner as other sources going forward."[48] This is in contrast to EPA's Final Guidance statement that "if a source installed and is currently operating controls to meet BART emission limits, it may be unlikely that there will be further available reasonable controls for such sources."[49] Therefore, a state must first subject a source to a four-factor analysis under section 51.308(f)(2)(i) before it is able to determine whether there are no emission reducing options available (including upgrades to existing controls).

Regarding which control measures states should consider in assessing reasonable progress, EPA states "there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures. A range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set."[50] This conflicts with past guidance and with the Regional Haze Rule. Although there is no requirement that controls required under the reasonable progress requirements of the Regional Haze Rule uniformly be the most stringent available, not considering this level of control bypasses section 51.308(f)(2)(i), which requires that the state perform a four-factor analysis. A state cannot consider "the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment" unless it considers all feasible controls available, including upgrades to existing controls.

EPA acknowledged that a range of controls should be evaluated in a four-factor analysis in its Draft Guidance:

> In order to define a control measure with sufficient specificity to assess its cost and potential for emission reductions, the state should specify and consider the range of control efficiencies that the measure is capable of achieving. For example, when

[45] *Id.* at 23-25.
[46] *Id.* at 25.
[47] *See* 70 Fed. Reg. at 39,163-64.
[48] 82 Fed. Reg. at 3083 (emphasis added).
[49] Final Guidance at 25.
[50] *Id.* at 29.

> evaluating a flue gas desulfurization system to reduce SO_2 emissions, the state should consider both a system capable of achieving a 90 percent reduction in SO_2 emissions as well as a more advanced system capable of achieving a 97 or 98 percent reduction. The state should not limit its analysis to either an unrealistically high and prohibitively expensive control efficiency or to a control efficiency that is substantially lower than has been achieved at other sources.[51]

Furthermore, EPA does not require that states secure the operation of controls with this level of efficiency through an enforceable commitment.

Just because a source has the most effective or highly effective control technology does not mean that it is required to be operated to a level reflective of its maximum pollution reduction capability. Thus, states should not be screening such sources out of review during the second implementation period. By allowing states to "screen out" and choose not to select such sources for a full four-factor analysis, EPA may be allowing states to ignore very cost-effective emission reducing options like simply requiring sources with highly effective controls to operate those controls in the most effective manner to reduce air pollutants. EPA should revise the Final Guidance to recommend that sources with existing pollution control technology evaluate options that could improve the emissions reduced through more effective use of that control technology. This could include requiring year-round operation of controls, reducing capacity, imposing more effective percent reduction requirements, requiring sources to meet more stringent emission limits, or requiring that emission limits apply on shorter averaging times to ensure continuous levels of emission reduction.

F. States should ensure that modeled emissions are tied to enforceable limits for sources with appropriate averaging times that reflect year-round abilities of existing controls or operation.

EPA should revise the Final Guidance to recommend that wherever possible, whether they are screened in or out, states should make sure that the emissions relied upon in the state's RPG demonstration are enforceable, and also that they reflect the lowest emission rates feasible at the facility given its existing configuration. This is particularly true for major sources that are screened out on the basis of emissions that reflect unenforceable conditions.

However, this is also true for sources that are screened out on the basis of emissions that do not reflect their full capacity for emission reductions. For example, if a source is screened out with emissions that reflect using its controls only seventy-five percent of the time, the state should nevertheless require year-round operation of the control. Requirements reflecting existing capacity for emission reductions are inherently reasonable, and represent low hanging fruit necessitating reduced resource expenditure for potentially large gain. Moreover, states routinely rely on actual emissions in assessing current visibility and using that assessment as a jumping off point to determine if additional reductions are necessary. Where a state is to rely on operational

[51] Draft Guidance at 87.

realities, such reliance must be justified by enforceable emission limits. Indeed, failing to take advantage of such reasonable progress measures is an example of one of the pitfalls of using this type of a screening process in the first place. EPA should recommend that states assure reasonable progress by requiring that sources have enforceable limits or conditions reflecting their full emission reduction capacity if they are to be screened out.

G. States must include both "dominant" and "non-dominant" pollutants in their analyses of controls.

In Section II.B.3.a of the Final Guidance, EPA advises states that they can skip analyses of controls for sources with "non-dominant" pollutants. Specifically, EPA states:

> When selecting sources for analysis of control measures, a state may focus on the PM species that dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors. Also, it may be reasonable for a state to not consider measures for control of the remaining pollutants from sources that have been selected on the basis of their emissions of the dominant pollutants.[52]

This position, absent from the Draft Guidance, directs states to produce deficient regional haze SIPs and is in conflict with the Regional Haze Rule's requirements and preamble language in the 2017 Regional Haze Rule revision.

The preamble specifically states that a "reasonable progress analysis must consider a meaningful set of sources and controls that impact visibility. If a state's analysis fails to do so, for example, by . . . *failing to include cost-effective controls at sources with significant visibility impacts*, then the EPA has the authority to disapprove the state's unreasoned analysis and promulgate a FIP.[53] This provision in the Guidance would allow states to arbitrarily determine that because one pollutant has a greater impact on visibility at a Class I area(s), the state may simply ignore other visibility impacting pollutants for one or all sources in the state emitting the non-dominant pollutants, despite the availability of cost-effective controls under reasonable progress criteria. It would also allow states to conclude that when examining a source that emits multiple pollutants that contribute to haze (e.g., SO_2, Nitrogen Oxide ("NOx")), potential reductions for the non-dominant pollutant can be summarily ignored. Furthermore, EPA does not provide any metric for what it considers a "dominant" pollutant.[54] For instance, if a state has determined that fifty-one percent of the visibility impact at a Class I area is due to SO_2, forty

[52] Final Guidance at 11.
[53] 82 Fed. Reg. at 3088. EPA states elsewhere in its 2017 Regional Haze Rule revision, that "A state may refer to its own experience, past EPA actions, the preamble to this rule as proposed and this final rule preamble, and existing guidance documents for direction on what constitutes a reasoned determination." 82 Fed. Reg. at 3099.
[54] Merriam-Webster defines dominant as "(a) commanding, controlling, or prevailing over all others," or as "(b) very important, powerful, or successful."

percent is due to NOx, and nine percent is due to PM, would SO_2 be considered dominant (and consequently the only analyzed pollutant), or must its share of the visibility impact be greater?

This provision in the Final Guidance has potentially far-reaching negative impacts on the Regional Haze Rule's requirements that states make reasonable progress, as many large sources emit multiple types of visibility impacting pollutants. Still other sources may emit significant levels of non-dominant emissions for which emission reducing control or measures may be well within the framework of the four-factor analysis. If this is not corrected, a state could assume it would be justified in concluding that state-wide, SO_2 is its "dominant" pollutant and forego control analysis of a large gas-fired power plant emitting thousands of tons of NOx which could also significantly impact visibility at one or more Class I areas.

The Final Guidance also directly conflicts with multiple sections of the Regional Haze Rule. For instance, a state following the guidance would not be able to determine if it was even subject to section 51.308(f)(3)(ii)(B), because by arbitrarily excluding pollutants or entire sources from review it could not determine if it "reasonably [was] anticipated to contribute to visibility impairment in a mandatory Class I Federal area in another State." Nor could that state "demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area." Similarly, if that state's RPG was above its URP, it could not satisfy section 51.308(f)(3)(ii)(A), which requires the same demonstration. Such a state would also not be able to reasonably satisfy its state-to-state consultation requirements under section 51.308(f)(2)(i), which requires it to "evaluate and determine the emission reduction measures that are necessary to make reasonable progress" and "include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy." By severely compromising the entire foundation of a state's technical demonstration, EPA is directing states to submit deficient SIPs. For these reasons, EPA should delete the above-quoted language from the Final Guidance.

H. States cannot eliminate VOCs and ammonia emissions from consideration.

In Section II.B.3.a. of the Final Guidance, EPA also advises states that irrespective of their particular state emissions inventories or the acknowledged potential impacts of VOCs and ammonia on Class I areas, they can completely disregard these pollutants. Specifically, EPA states:

> In the first implementation period, many states eliminated VOC and ammonia emissions from consideration based on the expectation that anthropogenic VOC emissions make only a small contribution to visibility impairment and that formation of nitrate and sulfate PM is most effectively reduced by reducing emissions of NOx and SO_2 rather than by anthropogenic emissions of ammonia. EPA believes that, in general, this

> would also be a reasonable approach for the second implementation period.[55]

This position is completely absent from EPA's regulations and was not present in the Draft Guidance.

VOCs are organic chemicals emitted by products or industrial processes that when released into the atmosphere can react with sunlight and NOx to form tropospheric ("ground-level") ozone. In addition, VOCs are important precursor of Secondary Aerosol Formation ("SOA"). SOA comprises a large fraction of atmospheric aerosol mass and can have significant effects on atmospheric chemistry, visibility, human health, and climate.[56] A major source of VOCs in the United States is the oil and gas industry, which includes wells, gas gatherings and processing facilities, storage, and transmission and distribution pipelines. According to data from EPA and the Energy Information Agency ("EIA"), more than 20 million tons of VOCs are emitted from point and non-point sources in the oil and gas industry every year. Studies on oil and gas emissions have indicated that VOC source signatures associated with oil and gas operations can be clearly differentiated from urban sources dominated by vehicular exhaust emissions.[5758] According to a recent air quality study by the National Park Service ("NPS") in Carlsbad Caverns National Park, high levels of light alkanes such as ethane, propane, butane, and, pentane compounds were consistent with oil and gas emissions. However, high alkanes ("$>C_8$") and aromatics are assumed to contribute more significantly to SOA formation.[59]

In California alone, statewide agricultural operations produce an average of 272.12 tons per day ("tpd") of ammonia ("NH_3") emissions.[60] Of those 272.12 tpd, 158.50 tpd is attributed to "agricultural waste" specifically from dairy cattle.[61] In regions such as California's heavily polluted San Joaquin Valley, ammonia concentrations are found to be much higher than NOx

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[55] Final Guidance at 12.
[56] Ziemann, Paul J., & R. Atkinson, *Kinetics, products, and mechanisms of secondary organic aerosol formation*, 41, no. 19 Chem. Soc'y Reviews 6582, 6582 (2012).
[57] *See* Odum J.R., T. Hoffmann, F. Bowman, D. Collins, R.C. Flagan, & J.H. Seinfeld, *Gas/Particle Partitioning and Secondary Organic Aerosol Yields*, 30 Environ. Sci. Technol., 2580, 2580-2585 (1996).
[58] *See* Swarthout, R. F., Russo, R. S., Zhou, Y., Hart, A. H., and Sive, B. C., *Volatile organic compound distributions during the NACHTT campaign at the Boulder Atmospheric Observatory: Influence of urban and natural gas sources*, J. Geophys. Res. Atmos., 118, 10,614–10,637, (2013), *available at* https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/jgrd.50722.
[59] Ziemann, *supra* note 56, at 6583; *see also* Takekawa, Hideto, Hiroaki Minoura, and Satoshi Yamazaki, *Temperature dependence of secondary organic aerosol formation by photo-oxidation of hydrocarbons*, Atmospheric Environment 37, no. 24, 3413-3424 (2003).
[60] California Air Resources Board, 2016 SIP Emission Almanac Projection Data by EIC: Annual Average Emissions (Tons/Day) Statewide, Miscellaneous Processes 620-Farming Operations, https://www.arb.ca.gov/app/emsinv/2017/emseic_query.php?F_YR=2012&F_DIV=-4&F_SEASON=A&SP=SIP105ADJ&SPN=SIP105ADJ&F_AREA=CA&F_EICSUM=620.
[61] *Id.*

concentrations.[62] When mixed with the region's NOx emissions (primarily from mobile sources), this excess ammonia helps form high levels of haze causing ammonium nitrate, which accounts for the majority of PM2.5 emissions found in the San Joaquin Valley.[63]

The San Joaquin Valley is home to multiple communities such as Bakersfield, Fresno, and Visalia that rank amongst the very topmost polluted cities for both annual and twenty-four hour PM2.5 pollution. [64] The entire air basin is also listed as being in extreme nonattainment with the 1997 and 2006 PM2.5 NAAQS standards.[65] As it relates to regional haze pollution, the San Joaquin Valley is located directly adjacent to the Southern Sierra Nevada Mountains, home to heavily polluted Class 1 areas like Sequoia and Kings Canyon National Parks—both of which fall within the jurisdiction of the San Joaquin Valley Air District.

Despite ammonia being a major precursor to PM2.5 pollution in the region, its emissions are currently not controlled in the San Joaquin Valley under the state's various PM2.5 SIPs.[66] Beyond ammonia, agricultural sources in California also produce and average of 145.90 tpd of direct PM10 and 21.79 tpd of direct PM2.5 emissions.[67]

In its 2005 BART amendments to the Regional Haze Rule, EPA left it to the states to individually determine if these two pollutants, which EPA acknowledges can potentially impact visibility, should be addressed.[68] In the Draft Guidance, EPA acknowledged that much of its guidance on BART remained applicable to the second round of SIPs and included an entire appendix devoted to identifying which portions of the BART guidance remained applicable.[69] This appendix has been deleted in EPA's Final Guidance. By arbitrarily excluding potential visibility-impairing pollutants from review, EPA's guidance conflicts with the same sections of the Regional Haze Rule as described *supra* section III.G, primarily preamble language to the 2017 Regional Haze Rule revision and sections 51.308((f)(3)(ii)(A), 51.308((f)(3)(ii)(B), and 51.308(f)(2)(i). EPA should revise the Final Guidance to direct states to inventory and evaluate potential visibility-impairing pollutants including VOCs and ammonia and determine associated control measures necessary to make reasonable progress. .

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[62] San Joaquin Valley Air Pollution Control District, 2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards, at 5-6, http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/2018-Plan-for-the-1997-2006-and-2012-PM2.5-Standards.pdf.
[63] *Id.* at 3-12.
[64] American Lung Association, 2019 State of the Air Report: Most Polluted Cities Ranking, https://www.lung.org/our-initiatives/healthy-air/sota/city-rankings/most-polluted-cities.html.
[65] San Joaquin Valley Air Pollution Control District, *supra* note 62, at ES-8.
[66] *See generally, id.* at 4-1 through 4-34.
[67] *See* California Air Resources Board, *supra* note 60.
[68] *See* 70 Fed. Reg. 39,104, 39,112-14 (July 6, 2005). EPA stated that scientific and technical data shows "that ammonia in the atmosphere can be a precursor to the formation of particles such as ammonium sulfate and ammonium nitrate . . . [and] certain aromatic VOC emissions such as toluene, xylene, and trimethyl-benzene are precursors to the formation of secondary organic aerosol." *Id.* at 39,114.
[69] Draft Guidance at Appendix D.

I. Light extinction thresholds should be tailored to Class I areas and low enough to bring in most sources of visibility-impairing pollution.

States choosing light extinction as a metric for visibility impacts should use Class I-specific figures to identify sources for a four-factor analysis. If a threshold is applied, states must ensure that the threshold is low enough to bring in most sources harming a Class I area. In the Final Guidance, EPA recommends visibility metrics and thresholds in terms of inverse megameters of light extinction.[70] Although light extinction may be acceptable as a metric, states should not use a generic extinction threshold for selecting sources for consideration of pollution controls for each of the Class I areas evaluated in their regional haze SIPs. If a light extinction threshold is too high, it can significantly limit the amount of sources a state evaluates for controls to make reasonable progress.

States must make clear how each source's visibility impacts are to be determined. States must explain whether the sources' potential emissions were modeled, what visibility-impairing pollutants were modeled for each source, whether all units were modeled for all sources, whether sources were modeled for impacts on the twenty percent worst days or some other timeframe, and identify and allow public review of and comment on the technical approach that the state employed to determine source-specific visibility extinction, pursuant to 40 C.F.R. § 51.308(f)(2). Any proposed extinction threshold for defining sources to target for controls is only as good as the underlying technical analysis to define if a source exceeds the extinction threshold. States must address these requirements and justify any and all extinction thresholds that they rely on for each Class I area impacted by states' sources.

For any souces that exceed an extinction threshold but are not subject to reduction requirements, states should provide a thorough four-factor analysis of controls or provide justification as to why a four-factor analysis would not likely lead to a determination that additional controls are needed to make reasonable progress. For any sources that a state claims already has adequate controls or justifies for other reasons that a four-factor analysis of controls would not result in additional controls, the state must document in its regional haze SIP why it makes this finding. To the extent such justification is relying on other regulatory or permit requirements, the state must document those regulatory or permit requirements in detail and indicate whether such requirements are already or will be submitted to EPA as part of the SIP

J. State's using the Q/d metric should include all visibility-impairing pollutants when calculating a source's annual emissions.

In Section II.B.3.b of the Final Guidance, EPA discusses the use of a source's annual emissions in tons divided by distance in kilometers between the source and the nearest Class I area (often referred to as Q/d) as a surrogate for source visibility impacts, along with a reasonably selected threshold for this metric.[71] As EPA notes, although Q/d is the least

[70] Final Guidance at 19.
[71] Final Guidance at 13.

complicated technique, it should "be limited to source selection for the purpose of developing a list of sources for which a state may conduct a four-factor analysis" because the metric is a less reliable indicator of actual visibility impact.[72]

EPA should revise the Final Guidance to require states using the Q/d metric to include all visibility-impairing pollutants when determining the annual emissions being used to obtain a source or source category's estimated visibility impacts. As discussed further *supra* section III.H, states cannot eliminate certain emissions, such as VOCs and ammonia emissions, from consideration. Additionally, EPA should recommend that states using the Q/d metric not use the Q/d threshold from the first implementation period for the second implementation period. Rather, the Q/d threshold should be lower in order to address more sources, including sources that are lower emitting and sources that are further in distance than the sources addressed in the first implementation period.

IV. Determination of affected Class I areas in other states

A. States must use methods permitted by statute and regulation to identify its sources that impact visibility at Class I areas in other states, not merely any "reasonable method."

In Section II.B.2 of the Final Guidance, EPA inserts a blanket statement that jeopardizes making progress towards the Clean Air Act Class I visibility goal and obfuscates the Regional Haze Rule's requirements regarding how a state should identify its sources that impact the visibility at Class I areas in other states: "As an initial matter, a state has the flexibility to use any reasonable method for quantifying the impacts of its own emissions on out-of-state Class I areas, and it may use any reasonable assessment for this determination."[73]

EPA does not provide any explanation or examples of what it considers "reasonable." Thus, this statement would allow a state to use any methodology, regardless of its scientific rigor, to identify those sources. Furthermore, once having identified these sources, however loosely, the state can then "assess" those sources any way it wishes. Confusingly, EPA seems to distinguish between quantifying the impacts of these sources and assessing these impacts. This single statement would serve to hand a state seemingly unlimited discretion over a key step in preparing its SIP, in marked contrast to what it proposed.

As EPA states in its 2017 Regional Haze Rule revision:

> On July 8, 2016, we released Draft Guidance that discusses how states can determine which Class I areas they ''may affect'' and therefore must consider when selecting sources for inclusion in a four-factor analysis. The Draft Guidance discusses various approaches that states used during the first implementation

[72] *Id.*
[73] Final Guidance at 8.

> period, provides states with the flexibility to choose from among these approaches in the second implementation period, and recommends that states adopt ‘‘a conservative . . . approach to determining whether their sources may affect visibility at out-of-state Class I areas.[74]

Indeed, EPA's Draft Guidance did provide actual guidance to the states on this issue:

> Once contributions by sources, groups of sources or geographic areas have been quantified in some manner, the EPA recommends that states adopt a conservative (more protective approach of visibility) approach to determining whether their sources may affect visibility at out-of-state Class I areas. For example, states could consider all Class I areas for which the state contributes at least one percent to anthropogenic light extinction from all U.S. sources on any day within the 20 percent most impaired days. States may choose a different threshold to determine which out-of-state Class I areas may be affected by the States sources, but must provide an adequate explanation of why the threshold is sufficiently protective of visibility.[75]

EPA followed this statement with more than twelve pages of highly technical guidance detailing approaches it deemed acceptable.[76] The Final Guidance deletes most of this and provides a summary approach void of technical rigor or analytical teeth. The Regional Haze Rule makes plain that a state's long-term strategy, including its application of the four statutory factors, be comprised of a robust initial step—the assessment of the state's emission sources on downwind states' Class I areas. However, by diminishing actual guidance and inventing this undefined and ambiguous standard, EPA creates confusion and ambiguity for states, leaving states to determine reasonability on a SIP-by-SIP basis. EPA should restore the discussion and directives to states from the Draft Guidance.

B. Application of a threshold for cumulative impacts to multiple Class I areas.

EPA should reconsider and revise the Final Guidance to recommend that states quantitatively document the results of the screening process for each Class I area rather than presenting only the impacts at the most affected or nearest Class I area. This allows the public to know the scope of the source's impacts and assures that the SIP comports with the letter and spirit of the regional haze program, a program grounded in the fact that regional haze is a regional problem and that Class I area impacts are felt typically by a multitude of sources' pollution that defy state boundaries.

EPA should also make clear that states must consider cumulative impacts of sources or groups of sources to all affected Class I areas. A source's cumulative impacts across Class I

[74] 82 Fed. Reg. at 3094.
[75] Draft Guidance at 58.
[76] Draft Guidance at 58-70.

areas provides a valuable screen to identify sources for further analysis. As EPA conceded and the court found in *Nat'l Parks Conservation Ass'n v. EPA*, in considering the visibility improvement expected from the use of controls, states must take into account the visibility impacts at all impacted Class I areas rather than focusing solely on the benefits at the most impacted areas.[77] This must include sources that have relatively small impacts in isolation but larger cumulative impacts either in the aggregate or across Class I areas.

V. Ambient data analysis

A. States must prioritize emissions within their borders to achieve reasonable progress.

International emissions contribute to visibility impacts. Rather than encouraging states to pursue an adjustment to the end goal of natural visiblity due to international emissions, EPA should be directing states to focus on the emissions within their borders for which requirements would help achieve reasonable progress. We encourage EPA to work with states, FLMs, stakeholders, and other countries to develop emissions inventories for cross-border pollution as well as scientifically valid methods for assessing long range emissions transport. However, the development of accurate accounting and modeling should not come with the expense of postponing or ignoring domestic emission-reducing measures. EPA's updated 2028 modeling[78] attempts to incorporate international emissions, but the agency itself makes clear that the science upon which the modeling rests is questionable.[79] EPA should reconsider and revise its Guidance to clarify that assessing international emissions is a work in progress and opportunity for partnership across a broad set of stakeholders, but the mandate of the Clean Air Act compels states to take measures to make reasonable progress by reducing emissions in their borders, not look to analysis to excuse doing so because other nations also contribute to regional haze.

We also urge EPA to revise the Final Guidance to clarify that affected states also have an obligation to take appropriate action to address international emissions.[80] Although EPA and the states are not required to "compensate" for international emissions, it is well within EPA and the states' rights and obligations to formally request reductions from international sources where appropriate, or to take permitting actions in the United States that will lead to emission reductions in other countries.

For example, Mexico's Carbon I and II power plants, which are less than twenty miles from the Texas border, are responsible for significant levels of pollution across several of the border states. Despite noting the significant impact of Mexican sources on its Class I areas, and

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[77] *Nat'l Parks Conservation Ass'n v. EPA*, 803 F.3d 151, 165 (3d Cir. 2015).
[78] EPA, Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling (Sept. 19, 2019), https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf ("Updated 2028 Modeling").
[79] *Id.* at 67.
[80] 64 Fed. Reg. 35,714, 35,755 (July 1, 1999) ("The States retain a duty to work with EPA in helping the Federal government use appropriate means to address international pollution transport concerns.").

requesting federal efforts to reduce impacts from international emissions,[81] Texas approved water discharge and mining permits for a coal mine in Maverick County. Rejecting these permits instead would have prevented the Mexican company Dos Republicas from mining high-sulfur coal that is transported and burned at the Carbon I & II facilities. EPA should remove its false implication that international emissions are entirely "uncontrollable" and should instead make clear that states must demonstrate that they are doing what is within their control to address international emissions—both generally and in particular.

EPA also discusses an "adjustment" to the URP for prescribed wildland fires. Wildfires, particularly in the West, have grown hotter, bigger, and more frequent with climate change. We recognize the role of prescribed fire in both managing fire size due to climate impacts and in restoration of natural ecosystems—which can, if effective, reduce the size and scale of fires later. There are, as a result of increased prescribed fire, potential benefits to both short- and long-term air quality. In planning for prescribed wildland fires, states should consider effects on visibility, alongside health and other concerns, including potential control measures and the potential benefits. A State cannot adjust a URP based on prescribed fires unless these fires actually result in visbility impairment on the "most-impaired" days. The Final Guidance should be clear that analysis of and planning for prescribed wildland fires need to be tailored to the planning period basis and would not automatically apply to the next planning period.

VI. Characterization of factors for emission control measures

A. States should identify and consider the best available emission control measures in the four-factor reasonable progress analysis.

In Section II.B.4.a of the Final Guidance, EPA advises states that they have the flexibility to reasonably determine which control measures to evaluate, and the agency lists examples of types of emission control measures states may consider.[82] EPA should reconsider its approach to ensure that the best controls for a source or source category are identified, evaluated, and the appropriate option determined. Identification of all available control measures is an important first step to ensure the best controls or emission reduction measures emerge from a four-factor analysis. However, EPA should revise the Final Guidance to ensure evaluation of the best control options.

1. EPA should reiterate and expand upon Step 1 of the BART-Guidelines regarding the identification of all available emission control techniques.

EPA should encourage states to consider various sources of information and types of emissions control techniques in developing its long-term strategy. Specifically, EPA should make clear that states must look to new source review control technology determinations, including major source BACT and LAER determinations, as well as state minor source BACT

[81] Texas Revisions to the State Implementation Plan (SIP) Concerning Regional Haze, at ES-2 (Feb. 25, 2009).
[82] Final Guidance at 29-30.

determinations. EPA should also recommend that states evaluate technologies that were considered in applicable new source performance standards, as well as those emission controls that were required in applicable new source performance standards.[83] EPA should also recommend that states consider the control techniques evaluated and required for similar source BART determinations.

In addition, EPA should recommend that states consider BACT determinations and other new source control requirements that states have adopted in minor new source review permits. Several states have minor source BACT provisions which may provide useful information for control technology considerations, and/or states have adopted targeted emission control requirements for source categories that do not have parallel federal requirements.[84]

Further, EPA should recommend that states investigate controls for source categories evaluated in reasonably available control measures ("RACM")/ reasonably available control technology ("RACT") and best available control measures ("BACM")/BACT determinations for nonattainment areas, a good starting point for information for control techniques available for a particular source category. States should also be encouraged to consult vendors or vendor groups such as the Institute of Clean Air Companies for control techniques for sources or source categories.

States should consider inherently lower-emitting processes, by themselves, and in combination with add-on controls. A state should not reject a combination of control measures altogether when the control measures could also be applied independently, unless the state is instead focusing on a control measure that is more effective at reducing emissions than the individual control measures.

In general, EPA should provide flexibility for states to consider innovative technologies tied to quantifiable and enforceable emission reduction requirements and to consider control techniques that some could view as "redefining the source" such as a change in fuel form. The BART Guidelines seemed to limit such controls from consideration for BART. Setting aside whether this was appropriate for BART determinations, States should not be constrained when evaluating measures to consider for the long-term strategy to make reasonable progress towards the national visibility goal.

In evaluating measures for the long-term strategy, states may need to address sources that were constructed many decades ago and/or sources to which pollution controls have not typically

[83] As EPA acknowledges in the BART guidelines, the NSPS standards do not always require the most stringent level of available control technology for a source category. 40 C.F.R. Part 51, Appendix Y, Section IV.D.2. In some cases, EPA evaluates more stringent controls in an NSPS proposed rulemaking, but ultimately requires a less stringent control to set the NSPS standard. EPA should make clear that NSPS standards are likely insufficient for purposes of reasonable progress determinations because the standards will not be reflective of the reduction measures available and otherwise meeting the four factors as SIPs are being advanced.

[84] *See, e.g.*, Colorado Regulation No. 7 – Control of Ozone via Ozone Precursors and Control of Hydrocarbon via Oil and Gas Emissions, https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=8546&fileName=5%20CCR%201001-9.

been applied. There may be little experience with applying pollution controls to such sources. However, the lack of information on "available" control technologies should not be used as a justification to eliminate a source from consideration of controls (or to only evaluate less effective controls). In such cases, States should be encouraged to consider innovative technologies, technologies that may not have historically been applied to the source type but could be transferred to the source type, emission unit replacement with more energy efficient/less polluting technology, and other such measures in evaluating how to best reduce haze-forming pollution from the source or source type.

2. EPA should advise states how to determine "available" and "technically feasible" control techniques for long-term strategy measures.

EPA should elaborate on how to determine whether a control technique is considered "available" or "technically feasible" for a source or source category. Section IV(D)(1) of the BART Guidelines[85] states in part that that "available retrofit control options are those with a practical potential for application to the emissions unit . . ." and "technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; we do not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice." EPA should recommend that states take a broader view in determining what control strategies are "available" for a source or source category, especially if traditional pollution controls had not been historically applied to that source category. In such cases, states may need to examine more innovative options for pollution control at such sources or source categories, including the consideration of promising pollution control options that have not already been demonstrated in practice but which offer quantifiable emission reductions.

Section IV(D)(1) of the BART Guidelines includes provisions to determine whether a control option is "technically feasible." Those provisions, as well as the discussion on available technologies, generally track guidance on evaluations for BACT determinations set out in EPA's New Source Review Workshop Manual.[86]

Sources often make availability or technical infeasibility arguments to avoid having to consider a pollution control, pointing out that that the control has not been used on the specific type of coal the source utilizes or on the particular size plant. Given that states may be having to determine controls for sources or source categories that have not been traditionally controlled in the long-term strategies, EPA should encourage states in such situations to fully evaluate controls that can be transferred from other source categories or that can be altered to accommodate the specific source or source category in question. EPA should recommend in such situations that states consult with, for example, environmental consultants, research technical journals, or air pollution control conference articles. States should also consider technologies demonstrated outside of the United States. EPA's New Source Review Workshop Manual describes how to

[85] 40 C.F.R. § Pt. 51, App. Y.
[86] U.S. EPA, New Source Review Workshop Manual, at B.17-B.21 (Draft Oct. 1990).

identify all control options "with potential application to the source and pollutant under evaluation."[87]

In summary, EPA should reconsider and revise the Final Guidance to elaborate on how states should evaluate available and technically feasible control techniques with the goal of ensuring that all potential controls with a practical application to a source or source category are considered in the development of the long-term strategy.

B. Cost analyses for the long-term strategy.

1. States must adhere to the accounting principles of the Control Cost Manual.

EPA should require states to follow the accounting principles and generic factors of EPA's Control Cost Manual because states and EPA have historically determined whether the costs of control measures are "reasonable" based on the costs that other similar sources determined in other regulatory actions including permits. [88] If EPA does not require all states to use the same accounting principles, it will be extremely difficult to compare costs of control between sources to evaluate whether the controls are cost effective.

2. States should compile and make publicly available the documentation for generic cost estimates.

EPA's Final Guidance suggests that states may reduce time and effort in determining control costs by using generic cost estimates or estimation algorithms, such as the Control Strategy Tool.[89] However, we request that EPA require the documentation for such generic cost estimates to be compiled and made publicly available. As stated in Sierra Club and National Parks Conservation Association's comments on EPA's proposed revisions to the Control Cost Manual, the Integrated Planning Model's SCR cost database is based on Sargent & Lundy's confidential database and the underlying data and methods used to develop the regression equations have not been publicly reviewed and analyzed.[90] Given that the cost estimates may be a primary basis for rejecting a control measure, the underlying data for such cost estimates must be publicly available.

C. EPA should reconsider and revise the Final Guidance regarding how to address energy and non-air quality environmental impacts of control measures.

EPA should state that the third factor of energy and non-air quality environmental impacts should generally be based on the same methodology laid out in the BART Guidelines. Section 8.1.1 of the BART Guidelines indicates that states must consider the energy and non-air quality environmental impacts as part of the cost analyses. With respect to taking into account non-air quality environmental impacts, we agree in general to take into account such impacts in

[87] *Id.* at B.10-B.11.
[88] Final Guidance at 31.
[89] *Id.* at 32.
[90] *See* September 10, 2015 Comment Letter from Sierra Club and National Parks Conservation Association to U.S. EPA, Docket ID No. EPA-HQ-OAR-2015-0341, at 8.

the cost analysis if the costs can be quantified. Otherwise, such impacts may need to be discussed qualitatively and weighed in the four-factor analysis.

EPA should also revise the Final Guidance and recommend that states analyze the climate and environmental justice impacts of regional haze SIPs. Although the Regional Haze Rule does not define "non-air quality environmental impacts," the BART Guidelines, which inform a state's reasonable progress analysis, explain that the term should be interpreted broadly.[91] Climate change[92] and environmental justice[93] impacts are the types of non-air quality impacts that states should consider when they determine reasonable progress measures for specific sources. Incorporating climate change and environmental justice impacts into the regional haze analysis will further states' climate and environmental justice policy goals, and it will also help states ensure that their actions related to regional haze planning support their other work on climate and environmental justice issues. Most of the same sectors and sources implicated under the regional haze program are also implicated in climate and environmental justice initiatives. As a result, when states determine "the emissions reduction measures that are necessary to make reasonable progress," they should assess how those measures will either reduce or exacerbate greenhouse gas emissions and/or environmental justice impacts on nearby disproportionately burdened communities.

VII. Decisions on what control measures are necessary to make reasonable progress

A. States cannot allow sources to discontinue the use of currently operating controls.

In Section II.B.5.e of the Final Guidance, EPA advises states how currently controlled sources may be able to discontinue those controls under reasonable progress:

> It is also possible that a source may be operating an emission control device but could remain in compliance with applicable emission limits if it stopped operation of the device. The state may reasonably consider based on appropriate factors whether continued operation of that device is necessary to make reasonable progress, such that the regional haze SIP submission for the second implementation period must make such operation of the device (or attainment of an equivalent level of emission control) enforceable.[94]

Suggesting to states that they may discontinue the use of controls that are already operating is antithetical to the regional haze program. Rather, EPA should revise the Final Guidance to require states to evaluate more effective operation of existing controls, including year-round

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[91] 40 C.F.R. pt. 51, App. Y at § (IV)(D)(4)(i), (IV)(D)(4)(j).
[92] *See, e.g.*, 74 Fed. Reg. 66,496 (Dec. 15, 2009) (EPA endangerment finding); Intergovernmental Panel on Climate Change, Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (2015), https://www.ipcc.ch/report/ar5/syr/.
[93] *See* EPA, Learn about Environmental Justice, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice (last visited April 24, 2020); Exec. Order No. 12,898, Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations, 59 Fed. Reg. 7629 (Feb. 11, 1994).
[94] Final Guidance at 43.

operation requirements. Further, the Clean Air Act is clear that visibility is not a factor in determining reasonable progress measures required at a source.

In evaluating controls for a source that already had a control installed, such as a wet or dry scrubber for SO_2 or SCR or selective non-catalytic reduction ("SNCR") for NOx, states must be required to evaluate whether these controls can be more effectively operated. Companies tend to operate their air pollution control systems to the level needed to ensure compliance with applicable emission limits rather than to the maximum emission reduction capability of the pollution control technology. For example, there are electrical generating units ("EGUs") that are only operating their installed SCR or SNCR systems during the ozone season to meet limits under the Cross State Air Pollution Rule ("CSAPR"). Indeed, in projecting operations and emissions scenarios for evaluating the CSAPR program, EPA included assumptions for dispatchable SCR, SNCR, and also scrubbers, which reflected the fact that no emission limits or consent decrees required continuous operation of the pollution controls installed at many EGUs. EPA should thus recommend that states, at a minimum, require year-round operation of existing scrubbers, SCRs, SNCRs, or other controls as one of the control options considered.

Additionally, there are numerous examples of scrubbers, SCRs, and SNCRs that, when operated, are not operated to achieve the maximum emission reductions that could be accommodated within the existing control technology at a particular unit, primarily because the applicable emission limitation does not require operation of those pollution controls to achieve the maximum emission reductions. As mentioned *supra* section III.E, states should consider sources that already have in place the most stringent controls available for additional control in the development of the long-term strategy during the second implementation period.

EPA should revise the Final Guidance to recommend that sources with existing pollution control technology evaluate options that could improve the emissions reduced through more effective use of that control technology. This could include requiring year-round operation of controls, imposing more effective percent reduction requirements, requiring sources to meet more stringent emission limits, and requiring that emission limits apply on shorter averaging times to ensure continuous levels of emission reduction.

VIII. Regional scale modeling of the long-term strategy to set the RPGs for 2028

A. States should use regional scale modeling to support their regional haze SIPs.

In Section II.B.6 of the Final Guidance, EPA advises states that they are not required to use regional scale modeling to support their regional haze SIPs. Specifically, under Step 6, EPA states that a state must:

> Determine the visibility conditions in 2028 that will result from implementation of the LTS and other enforceable measures to set the RPGs for 2028. Typically, a state will do

> this through regional scale modeling, *although the Regional Haze Rule does not explicitly require regional scale modeling*.[95]

Were a state to forego estimating source or source categories emitting visibility-impairing pollutants, as the guidance provides, it would not be able to satisfy a number of basic requirements of the Regional Haze Rule. Estimating the visibility impacts from a collection of sources is a prerequisite of establishing a state's RPG. As EPA explains in its 2017 Regional Haze Rule revision, this is a key first step in a state setting its RPG: "the 2007 guidance clearly describes the goal-setting process as starting with the evaluation of control measures. First, we recommended that states '[i]dentify the key pollutants and sources and/or source categories that are contributing to visibility impairment at each Class I area.'"[96] If a state did not estimate the visibility impacts from source or source categories, it could not satisfy the requirement in Section 51.308(f)(3)(ii)(A) that it demonstrate, "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area." Indeed, this misplaced advice is not even internally consistent with other sections of the Final Guidance, which cover many techniques for estimating the visibility impacts of sources or source categories. Estimating the collective visibility impacts of sources or source categories to determine the RPG is a fundamental requirement of the regional haze program.

In fact, there is no known substitute for the use of photochemical air quality models to project the visibility impact from thousands of individual sources, influenced by complex meteorological fields and atmospheric chemical interactions at a Class I area, ten years into the future, as EPA makes clear in Appendix W to Part 51.[97] The use of air quality models has been a cornerstone of the technical demonstration of the regional haze program (and many other air programs) since its inception. Almost every EPA Regional Haze Rule revision and guidance either discusses the use of air quality models or assumes their use. In fact, EPA recently updated its modeling guidance for regional haze.[98] The very first sentence of the section specifically devoted to regional haze is: "[t]his section focuses on the modeling analysis needed to set RPGs that reflect the enforceable emission limitations, compliance schedules, and other measures included in the long-term strategy of a regional haze SIP."[99] Part 51 makes it clear that air quality

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[95] Final Guidance, Table 1, at 6 (emphasis added).
[96] *See* 82 Fed. Reg. at 3092-93. Notably, EPA does not abandon its 2007 Guidance and in fact refers to in several places in its rule revision.
[97] *See* 40 C.F.R. Pt. 51; App. W, Section 2.0 (a), "Guideline on Air Quality Models," ("Increasing reliance has been placed on concentration estimates from air quality models as the primary basis for regulatory decisions concerning source permits and emission control requirements. In many situations, such as review of a proposed new source, no practical alternative exists."); *see also id.* at Section 1.0 (b), ("The impacts of new sources that do not yet exist, and modifications to existing sources that have yet to be implemented, can only be determined through modeling.") This is precisely the challenge of setting RPGs – accounting for modifications to potentially dozens of existing sources (e.g., installation of controls).
[98] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.s and Regional Haze, EPA 454/R-18-009, (Nov. 2018).
[99] *Id.* at 143.

modeling is a necessary tool in the setting of RPGs and EPA should not imply otherwise in its guidance.

Instead of guiding states on modeling, EPA repeatedly informs states that they can use "surrogates" to estimate visibility impacts of a body of sources. Specifically, EPA states that "the Regional Haze Rule does not require states to develop estimates of individual source or source category visibility impacts, or to use an air quality model to do so. Reasonable surrogate metrics of visibility impact may be used instead."[100] EPA lists a number of surrogates that can be used for this purpose, including Q/d, wind trajectories, and daily light extinctions budgets and states that states can use "other reasonable techniques."[101] However, although more strongly worded in its Draft Guidance,[102] EPA does state in its Final Guidance, "[s]urrogate metric here refers to a quantitative metric that is correlated to some degree with visibility impacts as they would be estimated via air quality modeling."[103] Consequently, although EPA tells states that modeling is unnecessary and that surrogate measures can be used, modeling is required in order to check the validity of visibility surrogates. EPA should reconsider this provision, and clarify that modeling is needed to assess the collective visibility impacts of sources or source categories to establish RPGs.

IX. Progress, degradation, and URP glidepath checks

A. If a state's RPG is above the URP, the state's "robust demonstration" must include a consideration of specific items identified by EPA.

In section II.B.7.c of the Final Guidance, EPA discusses what could constitute a "robust demonstration," required under section 51.308(f)(3)(ii)(A) when a state's RPG is above the URP.[104] EPA states that a simple "narrative explanation of how the state has already conducted the source selection and control measures analyses in such a manner that addresses the requirements of 51.308(f)(3)(ii)" may suffice.[105] EPA then goes on to note that such a state *may* consider a long list of additional items, including reconsideration of its visibility threshold, acceptable cost threshold, additional technically feasible controls, how its determination criteria compares to that of other states, etc.[106]

In contrast, EPA's Draft Guidance did not state that a simple narrative would suffice. The Draft Guidance stated that such a demonstration *should* include consideration of a similar listing

[100] Final Guidance at 12.
[101] *Id.* at 13.
[102] Draft Guidance at 76 ("Before relying on Q/d as a surrogate for screening purposes, a state should investigate how well Q/d relates to visibility impacts for the 20 percent most impaired and 20 percent clearest days, in terms of both the central tendency of the relationship (e.g., the regression line) and the variability of the relationship (e.g., the error of the regression). This understanding should be developed through relevant modeling of some actual cases or model plant scenarios, or another appropriate approach.")
[103] Final Guidance at 10 n.25.
[104] *Id.* at 50.
[105] *Id.*
[106] *Id.* at 50-51.

of items. EPA's pivot from *should* consider to *may* consider substantially misinterprets and is directly at odds with what the robust demonstration required under section 51.308(f)(3)(ii)(A) should contain.

Moreover, states should not rely on EPA's Updated 2028 Modeling[107] to determine which Class I areas are projected to be at or below the URP. Projected conditions for 2028 are tied to the 2064 natural conditions endpoint adjustments to account for international anthropogenic contributions, as well as wildfires. By EPA's own admission as discussed *supra* section V.A, these adjustments lack scientific validation and should not be relied on to determine whether a Class I area is on track to meet its URP in 2028.[108] The result of the updated modeling adjustments reduced the number of Interagency Monitoring of Protected Visual Environments ("IMPROVE") sites projected to be above the glidepath from forty-seven to eight. IMPROVE monitors are not the same as Class I areas, however many Class I areas share monitors; only ninety-nine monitoring sites (representing 142 Class I areas) were evaluated.[109] EPA must reconsider and revise the Final Guidance to specify what a "robust demonstration" under section 51.308(f)(3)(ii)(A) requires and that a state's demonstration should include consideration of the specific list of items identified by the agency.

X. Additional requirements for regional haze SIPs

A. States must submit to EPA the emission inventory used in a regional haze SIP.

In section II.B.8.c of the Final Guidance, regarding section 51.308(f)(6)(v) which covers the requirements for the state's emissions inventory, EPA states that "[t]he emission inventories themselves are not required SIP elements and so are not required to be submitted according [sic] the procedures for SIP revisions. The emission inventories themselves are not subject to EPA review."[110] This conflicts with the Regional Haze Rule, is internally inconsistent with the rule and other state requirements, and is impracticable. First, EPA's statement conflicts with several sections of the Regional Haze Rule. For instance, section 51.308(f)(2)(iii) requires that the state must document the following:

> [T]he technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I Federal area it affects. . . . The emissions information must include, but need not be limited to, information on emissions in a year at least as recent as the most recent year for which the State has submitted emission inventory information to

[107] *See* Updated 2028 Modeling.
[108] *Id.* at 67.
[109] *Id.* at 3 n.6.
[110] Final Guidance at 55.

> the Administrator in compliance with the triennial reporting requirements of subpart A of this part.

Here, it is clear that a state is required to document the technical basis of all aspects of its regional haze demonstration. A state's emission inventory is a foundational aspect of its technical demonstration. In fact, EPA specifically calls out "emissions information," and clarifies that the emissions information must include "information on emissions in a year at least as recent as the most recent year for which the State has submitted emission inventory information to the Administrator."[111]

Plainly, a state is required to submit the emission inventory it is using as part of its technical demonstration to EPA, and that inventory must include certain specified elements. Because states are already required to submit specified emission inventories to EPA as part of other requirements ("Part A"), EPA clarifies that a state may refer to that submission instead of physically including it in its SIP. However, the mere fact that EPA specifies a state may use an already prepared work product does not shield it from a review of its suitability for the task at hand. [112] For instance, EPA has frequently stated that states may use the technical work of RPOs in their SIPs. That position has never been interpreted to mean information is shielded from EPA review.[113] Indeed, EPA has a duty to review that inventory in the context of the state's regional haze SIP submission.[114] Thus, a state's emission inventory is an inseverable part of its regional haze SIP and subject to EPA's review.

Despite this, EPA appears to imply in its guidance that it cannot bring to the state's attention potential faults in the emission inventory a state used to support its regional haze SIP, nor even examine that inventory in the context of its review of the state's regional haze SIP. EPA should revise the Final Guidance to advise states that a state's emission inventory is a part of the state's SIP and subject to EPA's review.

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[111] *Id.*

[112] *See* EPA's "Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations," EPA-454/B-17-002, at 11 (May 2017), ("[Inventory information provided to EPA] will allow the EPA to make a determination whether the emissions information used in Regional Haze analysis is sufficient for the purposes of the SIP.")

[113] For instance, in the Texas FIP, EPA observed that under the current regulation each state "must document the technical basis, including modeling, monitoring and emissions information, on which the State is relying to determine its apportionment of emission reduction obligations necessary for achieving *reasonable progress* in each mandatory Class I Federal area it affects." 79 Fed. Reg. 74,818, 74,829 (Dec. 16, 2014) (emphasis in original). While the current regulations provide that, "[s]tates may meet this requirement by relying on technical analyses developed by the regional planning organization and approved by all State participants," 40 C.F.R. § 51.308(d)(3)(iii), the Texas haze rule clarified that in situations "where a regional planning organization's analyses are limited, incomplete *or do not adequately assess the four factors*, however, then states must fill in any remaining gaps to meet this requirement." *Id.* (emphasis added).

[114] In the 2017 Regional Haze Rule revision, EPA makes it a point to review a number of circuit court opinions that affirm EPA's review authority, including the Eight Circuit's conclusion that EPA "must 'review the substantive content of the . . . determination." 82 Fed. Reg. at 3090 (quoting *Ariz. el rel. Darwin v. EPA*, 815 F.3d 519, 531 (9th Cir. 2016).

B. States must ensure that FLM opinions and concerns are made transparent to the public, considered by the state and addressed in the SIP.

In Section II.B.8.a of the Final Guidance, EPA provides guidance to the states regarding the FLM consultation requirements in the Regional Haze Rule, 40 C.F.R. § 51.308. Although EPA reiterates that states are required to consult with FLMs, EPA should reconsider and revise the Final Guidance to ensure that states give credence to the opinions and concerns expressed by FLMs. FLMs have affirmative duties under section 169A(a) and (d) of the Clean Air Act as well as mandates to protect and manage public lands under the Wilderness Act[115] and the Organics Act[116]. Therefore, EPA should revise the Final Guidance to direct states that to work collaboratively with FLM to develop regional haze SIPs that satisfy federal agency duties and public resource protections.

XI. Overarching recommendations

A. EPA should emphasize that the end result must be reasonable progress.

EPA should make clear in a revised Final Guidance that the end result of any state's implementation plan must be real, reasonable progress. Consequently, each new plan must require that states actually reduce their emissions that contribute to visibility impairment. The statute requires each haze plan to contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress . . . ."[117] Therefore, any interpretation of the Regional Haze Rule via guidance should direct a state's long-term strategy to be more than just a hand waving exercise—each plan must require adequate emission limits and other enforceable measures to make reasonable progress.[118] EPA should revise the Final Guidance to explicitly provide that actually requiring emission reductions which constitute reasonable progress must be the outcome of the four-factor analysis to meet the applicable requirements; deliberation, no matter how well documented, is not enough. Emission reductions recognized through the four-factor analysis must result in emission reduction measures enforceable through a state or federal regional haze plan.

B. Decisions on which controls to require as part of the long-term strategy cannot merely ratify past determinations.

EPA must also revise the Final Guidance to clarify that decisions on which controls to require as part of long-term strategy cannot rest solely on controls required by past SIPs and state rules. Although EPA stated in the Draft Guidance that decisions on whether controls for a source or source category are cost-effective or provide sufficient visibility improvement cannot rely solely on past decisions evaluating controls for similar sources[119], that language is completely absent from the Final Guidance. EPA must revise the Final Guidance to state this point. For

[115] 16 U.S.C. §§ 1131-1136.
[116] 54 U.S.C. § 100101.
[117] 42 U.S.C. § 7491(b)(2).
[118] *See id.*
[119] Draft Guidance at 97, 103.

example, costs or technologies which were previously considered unreasonable or infeasible at a later date may become more common and may nevertheless be necessary in the second or future planning periods to make reasonable progress. Likewise, making reasonable progress in the current and future planning periods will require the implementation of controls that individually account for smaller visibility impacts than those contemplated in the first planning period and in other past emission reducing rules and permits. Therefore, EPA must revise the Final Guidance to direct states to conduct new source-specific, four-factor emission reduction analyses.

C. EPA must ensure that long-term strategies include appropriate measures to prevent future as well as remedy existing impairment of visibility.

The Clean Air Act not only requires that existing visibility impairment be remedied, but that future impairment be prevented. 42 U.S.C. § 7491(a)(1). As such, it is imperative that each state's long-term strategy be required to include measures to prevent regional haze visibility impairment and that such plans take into account the effect of new sources, as well as existing sources of visibility impairment. EPA must revise its Guidance to comport with this requirement.

EPA has historically relied on the prevention of significant deterioration ("PSD") permitting program and the visibility new source review ("NSR") requirements mandated by 40 C.F.R. § 51.307[120] to address this requirement of the national visibility goal.[121] These provisions essentially mandate that new and modified major sources that are subject to major source permitting requirements do not adversely impact visibility in any Class I area. However, much has changed in the PSD and NSR permitting programs since 1980. The current PSD rules, as well as the major source nonattainment NSR rules, now exempt many modifications at existing major sources that were previously subject to PSD review. As a result, the PSD and visibility NSR rules do not provide as comprehensive Class I areas protections as they previously did, due to impacts from modified sources. Further, there have been significant increases in emissions near some Class I areas due to oil and gas emissions and other activities that are not adequately addressed by the PSD permitting program.

EPA must revise its Final Guidance to ensure that states prevent future impairment by analyzing new and modified emission sources and by requiring mitigation of the cumulative visibility-impairing emissions. As we discuss below, it is especially important for EPA to articulate that states consider minor, area, and other new growth, or modification of stationary sources that are not subject to the Class I area protections of the PSD permitting and visibility NSR requirements.

[120] 40 C.F.R. §51.307(b)(2) and (c) provides that the PSD requirements of 40 C.F.R. §51.166(o), (p)(1) through (2), and (q) apply to new and modified major proposing to locate in nonattainment areas that may have an impact on visibility in a mandatory Class I area.
[121] *See* 45 Fed. Reg. 80,089 (Dec. 2, 1980).

1. The 2002 PSD and nonattainment NSR Rule revisions exempt many modifications from PSD permitting that could result in large, visibility-impairing emission increases from existing major sources.

EPA has historically relied on the PSD and nonattainment/visibility NSR permitting programs to meet the requirement of preventing future impairment of visibility. The PSD permitting requirements specifically provide for ensuring that a new or modified major source will not adversely impact visibility in a Class I area[122], and the EPA's visibility NSR rules in 40 C.F.R. §51.307(c) require new and modified major sources proposing to locate in nonattainment areas that may impact visibility in a Class I area to meet these same requirements of the PSD program.[123] However, the December 2002 revisions to the PSD and nonattainment NSR permitting requirements significantly reduced the scope of modifications that would trigger PSD or nonattainment NSR as major modifications by drastically changing the methodology for determining whether a significant emission increase would occur as a result of a modification.[124]

Despite these significant regulatory changes which reduced the scope of modified sources subject to PSD and nonattainment NSR permitting, EPA has never re-evaluated its reliance on the major source permitting programs as sufficient to prevent future impairment of visibility. However, these rules, as revised in recent years, will likely allow significant increases[125] in actual emissions from existing sources to occur without any evaluation of the impacts on visibility and without even applying BACT or LAER, due to being exempt from PSD or nonattainment NSR permitting.

In summary, the PSD and nonattainment NSR rules as revised in 1992 and 2002 now exempt many modifications that would have previously been subject to major source permitting, including the visibility requirements of the PSD program and visibility NSR rules. Thus, while the rules still include vital provisions for the prevention of future visibility impairment, the PSD and visibility NSR rules are no longer adequate by themselves to ensure the prevention of future visibility impairment. In light of this, EPA should revise the Final Guidance to clarify that states may not solely rely on the PSD and visibility NSR programs to prevent future impairment of visibility. EPA must ensure that states specify requirements in their SIPs to prevent future visibility impairment from the new source growth in any state that may increase visibility-impairing pollution and thus affect Class I area visibility.

2. Minor, area, mobile, and other source emissions must be evaluated to prevent future, as well as remedy existing, impairment of visibility.

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[122] 40 C.F.R. §52.21(o), (p)(1) and (2), and (q).
[123] 40 C.F.R. §51.307(b)(2) and (c).
[124] 67 Fed. Reg. 80,185, 80,186-89 (Dec 31, 2002) (also known as "NSR Reform" Rule).
[125] *See* Joseph Goffman, et al., EPA's Attack on New Source Review and Other Air Quality Protection Tools (Nov. 1, 2019), http://eelp.law.harvard.edu/wp-content/uploads/NSR-paper-EELP.pdf.

Although the Final Guidance mentions minor, area, mobile, and other emission sources, most of the discussion addresses major stationary sources. EPA should be more explicit in its expectation that states evaluate sources and source categories that are not major stationary sources as well, including the potential for growth in emissions from these sources. For example, given the increases in emissions from oil and gas development over the last 10 years,[126] it is clear that the existing SIPs and FIPs do not currently include adequate mechanisms for preventing visibility impairment from these sources as production ebbs and flows with economic conditions and other factors, such as deregulation and technology. EPA must revise the Final Guidance to clarify that states need to address these sources in the aggregate, rather than source-by-source.

There are several examples of rules and programs that may be necessary in a long-term strategy to prevent future impairment of visibility in Class I areas. EPA should revise the Final Guidance to direct states to consider these examples and include them where appropriate in SIPs.

a. Methods to address visibility-impairing emissions from oil and gas development

EPA should revise the Final Guidance to explicitly note that it expects states to review area sources like oil and gas, and should provide additional guidance on how to do so. Undoubtedly, this should begin with requiring states to collect better data on the emissions from oil and gas.

In many states, emissions from oil and gas development are a significant threat to visibility and air quality in Class I areas. Such development often occurs on federal lands that are near to or abut Class I areas For example, oil and gas development contributes to visibility impairment in public lands in Utah and Colorado where the NPS found that oil and gas development and leasing in the two states would "cause visibility impairment" at Dinosaur National Monument.[127] Additionally, NPS recently found impacts from oil and gas emissions at Carlsbad Caverns and San Pedro Parks Wilderness Class I areas, among others, based on 2008 emissions inventories—which do not capture more recent growth—and include only a portion of emissions from the production process.[128] Examples of Class I areas currently or potentially

[126] "The U.S. Energy Information Administration ("EIA") reports that oil production growth in the United States has risen by about 3 million barrels per day (from 5.8 to 8.72 MMb/d) from January 2001 to July 2014 (EIA, 2014a). Natural gas production has increased from 53.74 to 70.46 billion cubic feet per day within this time period (EIA, 2014a). The trend is expected to continue with the number of oil and gas wells in the lower 48 states projected to increase by 84 percent between 2013 and 2040 (EIA, 2014b)." Thompson et al., Modeling to Evaluate Contribution of Oil and Gas Emissions to Air Pollution, 67 Journal of the Air & Waste Management Association Vol. 4, 445 (Sept. 2016), https://doi.org/10.1080/10962247.2016.1251508.

[127] Memorandum from Regional Director, Intermountain Region, National Park Service, to Planning and Environmental Coordinator, BLM 9 (2013); *see also* Memorandum from Superintendent, Dinosaur National Monument, National Park Service, to Field Office Manager, BLM Vernal Field Office 2 (Aug. 2017); Krish Vijayaraghavan et al., Ramboll Environ US Corporation, 2017); BLM, Colorado Air Resources Management Modeling Study (CARMMS): 2025 CAMx Modeling Results for the High, Low and Medium Oil and Gas Development Scenarios, 104-05 (Aug. 2017), https://www.blm.gov/documents/colorado/public-room/data.

[128] Thompson et al., *supra* note 126, at 456; *see also* Table C6, *available at* https://www.tandfonline.com/doi/suppl/10.1080/10962247.2016.1251508?scroll=top.

impacted by oil and gas emissions include: Theodore Roosevelt and Lostwoods (Bakken Shale in eastern Montana and North Dakota); Wind Cave and Badlands (Powder River Basin in northeast Wyoming); Bridger and Fitzpatrick Wilderness Areas (Pinedale Anticline and Jonah Fields in western Wyoming); Mesa Verde (North and South San Juan Basin); Carlsbad Caverns and Guadalupe Mountains (Permian Basin in southeastern New Mexico and western Texas); and Canyonlands and Arches (Uintah, Paradox, and Piceance Basins in Utah and Colorado).

Significant information is available to enable states and EPA to develop strategies to reduce visibility-impairing emissions from this significant source category. However, these prior analyses do not substitute for meaningful consideration of oil and gas emissions reductions sufficient to meet the Regional Haze Rule's "reasonable progress" mandate. NPCA's recent report, "Oil and Gas Sector Reasonable Progress Four-Factor Analysis for Five Source Categories" assesses emissions controls for the five primary sources of visibility-impairing (and health harming) pollution in the sector: gas-fired reciprocating internal combustion engines ("RICE"); diesel-fired RICE; gas-fired combustion turbines; gas-fired heater, boilers, and reboilers; and flaring and thermal incineration of excess gas and waste gas.[129] The controls and practices included in this document represent various requirements for sources across the country and should be considered by states with emissions from the oil and gas sector.

Resource Management Plans ("RMPs") or land use plans issued by federal agencies explain how the agency will manage areas of public land over a period of time, usually ten to fifteen years. RMPs and amendments to those plans are required to go through a public review process under the National Environmental Policy Act ("NEPA"), which must include an analysis of projected impacts to all resources, including air quality. Such plans would include projections of oil and gas development, among other land use projections, on federal lands. Unfortunately, numerous RMPs have not been revised for decades, and only a few consider the effect of emissions from the planning area. EPA should revise the Final Guidance to require that states consider RMPs and other land use plans in determining the appropriate measures to prevent future impairment of visibility to include in regional haze SIPs. However, if RMPs are outdated or fail to consider the effects of visibility-impairing pollution from development, EPA must also indicate that those RMPs not be relied upon.

Recent NEPA analyses conducted for projected oil and gas development in RMPs can be useful tools for obtaining data regarding anticipated growth in such emissions. However, neither NEPA assessments nor RMPs are tools for preventing future impairment from oil and gas development. First, if adverse impacts are projected, the federal agency may make recommendations on mitigation methods to avoid adverse impacts, but neither the federal agency nor the local or state air permitting agency are under any obligation to implement such mitigation measures. Second, the federal agency is often making projections of expected amounts of development and in the types and emission rates of emissions units utilized. Those projections do

[129] Vicki Stamper & Megan Williams, Nat'l Parks Conservation Ass'n, Oil and Gas Sector Reasonable Progress Four-Factor Analysis for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration (Mar. 6, 2020) ("NPCA Report").

not always reflect the level of development that actually occurs, or the specific emission units and emission rates that are utilized. The Colorado Air Resources Management Modeling Study is one example of the type of information which can be developed in conjunction with the RMP process.[130]

In developing long-term strategies, EPA should direct states to use available information such as county-level reported emissions data and RMP and site-specific NEPA analyses, and request additional information to round out and make inventories accurate. To aid in this data gathering, EPA should direct industry to produce emissions inventories and submit them to states alongside an evaluation of emissions-reduction strategies and control technologies for this significant source of visibility impairment. Further, EPA should revise the Final Guidance to explicitly advise states on creating and making publicly available oil and gas emissions data.

States with significant oil and/or gas development should be required to consider the adoption of emission control regulations for the oil and gas development industry to reduce visibility-impairing emissions from such development.[131] Many states already require measures to reduce emissions from the sector. For example, California has enacted extensive air pollution requirements for oil and gas production, processing, and storage.[132] Colorado has also adopted emission requirements for the oil and gas industry.[133] Pennsylvania has also revised the state's oil and gas drilling regulations.[134] While these regulations may not be sufficient as to visibility impairment from the sector's emissions, the regulations provide relevant examples of states' decisions to address threats to air quality that are not covered by federal major source permitting requirements. EPA should identify the source types and associated emission-reducing measures available in the sector and use them to develop guidance to specify EPA's expectations of states in assessing these sources and requiring emission reduction measures from them. EPA must reconsider and revise the Final Guidance to require states to apply these and other control measures in their regional haze SIPs.

b. Minor New Source Review permitting programs

A state's minor NSR permitting program can be a useful tool to impose emission limitations and otherwise ensure that new source growth occurs in a manner consistent with making reasonable progress towards the national visibility goal. EPA should revise the Final Guidance to direct states to model new or modified minor NSR sources for their impacts on visibility in Class I areas. States could thus determine if the source's emissions would be consistent with making reasonable progress towards the national visibility goal, similar to the requirement in 40 C.F.R. §51.307(c) of the visibility NSR rules. Such a provision would also be

[130] *See* BLM, Colorado Air Resources Management Modeling Study (Aug. 2017), https://www.blm.gov/documents/colorado/public-room/data.
[131] NPCA Report at 7-10.
[132] California Air Resources Board, Oil & Natural Gas Production (last reviewed July 18, 2017), https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilandgas2016.htm.
[133] Colo. Regulation No. 7, Section XII, https://www.colorado.gov/pacific/cdphe/air/oil-and-gas-compliance.
[134] *See* Environmental Protection Performance Standards at Oil and Gas Well Sites, 46 Pa. B. 6431 (Oct. 8, 2016), http://www.pacodeandbulletin.gov/Display/pabull?file=/secure/pabulletin/data/vol46/46-41/1757.html.

consistent with section 7410(a)(2)(D)(i)(II) of the Clean Air Act, which requires SIPs to include adequate provisions prohibiting any source type from emitting any air pollutant which will interfere with measures to protect visibility. States could include criteria to ensure that the sources most likely to interfere with making reasonable progress are addressed, based on total emissions of visibility-impairing pollutants, distance to Class I areas, and/or other criteria focused on modifications at existing major sources that avoid PSD or nonattainment NSR review. EPA should instruct states to add such provisions to their minor NSR programs as necessary to ensure that their long-term strategies adequately prevent future impairment to visibility. Such provisions should also be incorporated and made enforceable through regional haze SIPs relying on such emission reductions to make reasonable progress.

States that decide to rely on minor NSR programs to prevent future impairment should be required to examine the relevant definitions and exemptions that exist in their programs to ensure that the types of sources that need to be addressed to prevent future impairment are indeed subject to the states' minor NSR programs. A state's minor NSR program also may need to be revised to include emissions from emitting units not typically covered under PSD permitting requirements, such as fugitive emissions.

Applicability at minor NSR sources should be based on projected changes in allowable or actual emissions from a baseline reflective of recent emissions. If a state is intending to rely on its minor NSR program to prevent future impairment of visibility, then the minor NSR program must be written in a manner to truly accomplish that intention. As other Clean Air Act programs fail to adequately integrate limits for new or modified sources, regional haze SIPs should be used directly for this purpose.

c. Provisions for other potential threats to visibility impairment

There are a number of source types other than those covered by a minor NSR permit program or oil and gas development that could potentially impair visibility. In recognition of this, EPA should revise its Final Guidance to recommend that states specifically include the analyses of these potential sources in their long-term strategies, and if necessary, adopt provisions to address them. For instance, if construction activities threaten future impairment, states should adopt control measures to mitigate air pollution at construction sites. As an example, the Sacramento Metropolitan Air Quality Management District applies air emissions requirements to construction sites.[135] California also has stricter mobile source emissions requirements (including for non-road engines) that apply under federal rules, and states with significant mobile source growth threatening future impairment could consider adopting such standards as their own.[136] EPA should encourage states to consider various measures to address

[135] *See* Sacramento Metro. Air Quality Management Dist., CEQA Guide, Ch. 3: Construction-Generated Criteria Air Pollutant and Precursor Emissions (April 2019), http://www.airquality.org/LandUseTransportation/Documents/Ch3ConstructionFinal4-2019.pdf.

[136] Congress preempted states from setting emission standards for mobile sources, except that California could set its own standards with EPA's permission and other states could opt into the stricter California standards (generally for ozone SIP purposes). 42 U.S.C. § 7543(e)(2)(B)(i)-(ii).

potential future Class I visibility impairment, based on the recent or planned growth in new source emissions expected for the state, that could threaten future impairment of visibility in any Class I area.

Additionally, to the extent that states have limited information on such sources, EPA should require that states collect and submit actual emissions increase data on minor modifications at existing sources in order to gather more information on the extent of minor source growth and on new minor, area, and other source growth.

Visibility-impairing emissions need to be inventoried and modeled from many sectors in order to properly inform the next round of haze plans. Several states have started collecting and submitting oil and gas emissions data to be inventoried and modeled for purposes of regional haze. For instance, the Western Regional Air Partnership has started collecting from its oil and gas producing states emissions for their modeling inventory.[137] However, there are several states not in the western region of the country, such as Pennsylvania and Virginia, which are significant producers of oil and gas, and should also be collecting and submitting oil and gas emissions data.[138] Furthermore, as noted *supra* section III.H, there is no inventory of emissions from the agricultural sector; states should develop such inventories and submit them with their regional haze SIPs.

Emissions data from wood burning devices should be modeled. As EPA has explained, the smoke from these devices "contains harmful particle pollution, also known as fine particulate matter or PM2.5, along with other pollutants including carbon monoxide, volatile organic compounds (VOCs), black carbon, and air toxics such as benzene."[139] EPA has also confirmed that residential wood combustion "accounts for 44 percent of total stationary and mobile polycyclic organic matter (POM) emissions, nearly 25 percent of all area source air toxic cancer risks and 15 percent of noncancer respiratory effects."[140] Furthermore, wood burning devices are a significant source of heating for many communities near Class I areas that struggle with regional haze pollution problems. Wood burning devices materially contribute to the significant proportion of particulate matter (fine and course) and VOC emissions that come from residential wood combustion in Arizona, Massachusetts, Minnesota, Nevada, Washington and other states, adding to regional haze visibility problems in Class I areas around the country.

While the collection and evaluation of much of this data should inform the next round of haze plans, we note that for the oil and gas sector, this data is sufficiently available such that regulation of the sector is appropriate and much needed in this second round of regional haze

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[137] *See* Western Regional Air Partnership ("WRAP"), EGU Emissions Analysis Project, https://www.wrapair2.org/EGU.aspx.
[138] *See* U.S. Energy Info. Admin., Pennsylvania State Profile and Energy Estimates (last updated Aug. 15, 2019), https://www.eia.gov/state/?sid=PA; U.S. Energy Info. Admin., Virginia State Profile and Energy Estimates (last updated Sept. 15, 2019), https://www.eia.gov/state/?sid=VA.
[139] EPA, Fact Sheet: Overview of Final Updates to Air Emissions Requirements for New Residential Wood Heaters, at 1 (Feb 4, 2015), https://www.epa.gov/sites/production/files/2015-02/documents/20150204fs-overview.pdf.
[140] EPA, Strategies for Reducing Residential Wood Smoke, Publ'n No. EPA-456/B-13-001 at 4 (Mar. 2013), https://www.epa.gov/sites/production/files/documents/strategies.pdf.

planning. EPA should specify that in order for a state to satisfy the requirements of proposed 40 C.F.R. § 51.308(f), states must consider the cumulative impacts from minor and other source growth that may affect future visibility impairment. With this information, states can determine the number and types of new source growth and magnitude of emissions that may threaten future visibility impairment, which can then assist states in developing targeted measures to prevent future visibility impairment and address regional haze from these source types. Such measures should be required to be part of the long-term strategy of the regional haze SIP.

In summary, EPA must revise the Final Guidance to require long-term strategies to include measures to ensure the prevention of future visibility impairment, as well as the remedying of existing visibility impairment in Class I areas, in accordance with the national visibility goal of the Clean Air Act. While the PSD and visibility NSR programs have some effective provisions for ensuring that new and modified sources subject to those permitting requirements do not threaten future visibility impairment, those programs are not sufficient to fully address the statutory requirement of preventing future impairment to visibility. EPA should require states to evaluate the threats to future impairment to visibility in any Class I area and to adopt provisions within regional haze SIPs to minimize emissions from such sources, and otherwise ensure that new source growth occurs in a manner consistent with making reasonable progress towards the national visibility goal.

XII. Conclusion

The Conservation Organizations respectfully ask that EPA reconsider and revise the Final Guidance as mentioned above.

Sincerely,

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July 10, 2020

Attn: Sandra Ely, Michael Baca, Mark Jones, and Kerwin Singleton

New Mexico Environment Department
Harold L. Runnels Building
1190 St. Francis Drive, Suite N4050
Santa Fe, New Mexico 87505
Re: Comments responding to 4-factor analysis submittals from identified oil & gas operators

Dear Ms. Ely, Mr. Baca, Mr. Jones, and Mr. Singleton,

We applaud the New Mexico Environment Department for welcoming public input and engagement throughout the development of its Regional Haze State Implementation Plan (SIP). We encourage the agency to require robust measures in its forthcoming SIP that will result in clearer skies and better air quality in our state and region's Class 1 Airsheds and communities.

We submit the attached expert comments on the four-factor analyses submitted by oil and gas facilities in New Mexico prepared by consultants Megan Williams and Vicki Stamper.

The report identifies numerous errors in operators' 4-factor analyses, including overestimation of interest rate and underestimation of life of controls, high capital estimates, failure to annualize costs in some cases, failure to provide emissions data that reflect a reasonable estimate of current and future actual operations, failure to document sources of emissions data and/or claims made regarding feasibility of controls, and failure to analyze available control options, including electrification.

We value NMED's inclusion of the 20 oil and gas facilities in the state's four-factor list and encourage the state to consider the contents of the attached report. We also request NMED assess control options applicable to source categories within the oil and gas sector from facilities that were excluded from its four-factor list. We urge the state to pursue electrification across the sector and in the alternative ask the state to apply category-wide requirements that would result in effective reductions in visibility-impairing pollution.[1]

We re-emphasize our request that NMED require electrification of engines as an overarching control option. As detailed in our May 22, 2020 cover letter accompanying a report on SCR feasibility at Lean Burn engines, electrification is ultimately the best option for reducing or eliminating emissions of NOx and all other air pollutants from gas-fired engines, thereby better reducing visibility and public health-harming emissions while helping New Mexico achieve its climate goals.

NPCA, Western Environmental Law Center, and other allies across the state are committed to working with the agency, operators, and utilities to identify solutions to overcome spatial and regulatory questions regarding oilfield electrification. We believe a harmonized framework is within reach to aggregate emissions and load, and generate power as a collective instead of operating as a dispersed set of points. Acknowledging the structural questions of oilfield electrification, we urge NMED to move forward on a parallel track with emission-limiting requirements necessitating electrification. Public lands and our communities deserve no less than a forward-looking regional haze plan that will effectively curb existing burdens and mitigate future impacts to air quality.

[1] We refer NMED back to the March 2020 NCPA Oil and Gas Four-Factor Report for consideration of effective control options for oil and gas source categories.

Notwithstanding the above, we offer the following summary takeaways from the attached assessment.

Summary of Effective Controls for Emission Units at New Mexico Oil and Gas Facilities

Combustion Turbines: Based on the revised and additional cost analyses provided in the report, SCR is cost effective for most combustion turbines at the New Mexico Gas Plants evaluated, with the few exceptions potentially being units that limit operating hours (for example, Kutz Canyon Unit 4 appears not to operate much based on its reported NOx emissions in 2016, should limited operations be enforceable, SCR would not be considered cost effective). While several operators summarily dismissed SCR as a feasible pollution control, they failed to support their claims, failing to provide site details or vendor proposals for claims of site constraints or other claimed retrofit difficulties. Although the attached report did not evaluate SCR cost effectiveness for the turbines at Kutz Canyon, Indian Basin or South Carlsbad due to lack of the needed inputs to utilize EPA's SCR cost spreadsheet, based on the other SCR cost analyses that are provided in the report for several similar combustion turbines, SCR should be considered the most cost effective, and most effective in terms of NOx reductions, for all combustion turbines operating more than ~1,000 hours per year. Beyond superior emission-reducing capabilities, SCR is also preferable as water use is not an adverse impact from use of the technology. We further note that SCR combined with SoLoNOx or other dry low-NOx combustion techniques may be the more fitting control option at some units because it would achieve the greatest reduction in NOx emissions.

Lean Burn Engines: As found in NPCA's March 2020 Oil and Gas Four-Factor Report, LEC has been required for retrofit controls—and has been deemed cost effective—for Lean Burn RICE units of a wide size range (e.g., down to 50 hp).[1] In many cases when considering LEC as a potential control, operators failed to specify achievable emission rates, often greatly underestimating the reductions that might be achieved and therefore underestimating the cost effectiveness of the technology. In the accompanying comments on four-factor analyses for oil and gas facilities in New Mexico, LEC is shown to be cost effective for most engines except for those that consistently operate a limited number of hours per year. However, it's important to note that, for some engines, operation may be limited in one year but that may not hold true for the same unit for other years. For example, Targa indicated that "[w]ith regards to the engine usage, Targa attempts to use its engines uniformly but this does not mean equally on a calendar year basis."[2] So, when looking at the cost effectiveness of LEC control for RICE it's important to consider how the engine will be used, on average, over the life of controls rather than just looking at one year that may or may not be representative of that engine's usage in other years. Generally, LEC is cost effective for the specific engine models analyzed operating over 1,000 per year and can achieve 80–90% NOx reduction and reduce NOx emission rates to 2 g/hp-hr and lower. In addition, SCR is shown to be cost effective for Lean Burn engines at the two plants that evaluated SCR for such engines (Roswell Compressor Station No. 9 and Jal No. 3 Gas Plant). Based on those cost analyses as revised in the attached report, SCR should also be considered a cost effective control, with the capability to achieve 90% NOx reduction and reduce NOx emission rates to 1 g/hp-hr.

Rich Burn Engines: As with Lean Burn RICE, control of NOx emissions from Rich Burn RICE has been widely required for retrofit controls—and deemed exceedingly cost effective—for a wide range of units (e.g., down to 50 hp). Specifically, the Rich Burn RICE units at Targa's Saunders Gas Plant NSCR was shown to be extremely cost effective—at under $300 per ton of NOx reduced—based on Targa's own analysis. No other New Mexico facilities submitted cost analyses for Rich Burn RICE but, given that NSCR is often extraordinarily cost effective, NMED should assess the Rich Burn units at the facilities that submitted four-factor analyses, even if those units have NOx emissions that fall below NMED's original cutoffs of 10 lb/hr or 5 tpy; cumulatively, control of NOx emissions from these emissions units using NSCR would be a very cost effective way to achieve additional, meaningful NOx reductions.

Amine Units/Acid Gas Flaring: For amine units and associated acid gas flares at gas sweetening plants, an acid gas injection well with a backup electric acid gas compressor is the minimum level of control of SO2

that should be required. In fact, NMED has required this suite of controls in some settlement agreements, according to information provided in the Targa Eunice Gas Plant and Monument Gas Plant four-factor analyses. For those locations at which an acid gas injection well may not work effectively, then a sulfur recovery unit (SRU) along with an incinerator *and* acid gas scrubber should be used to most effectively control SO2 emissions. Alternatively, a facility could employ both an acid gas injection well and a sulfur recovery unit, as is implemented at the Jal No. 3 amine unit, although improvements should be made at that facility, such as adding an acid gas scrubber to the SRU or routing the acid gas stream from the SRU to the acid gas injection well. Any maintenance or upset that requires the flaring of the acid gas stream from an amine unit can be a significant source of SO2 emissions and thus redundancy of controls is key for reducing/eliminating SO2 emissions associated with amine units at gas sweetening plants.

In a 2018 presentation from the Air Resources Division of the National Parks Service, entitled "Source Attribution Using Volatile Organic Compound Measurements to Assess Air Quality Impacts at Five National Parks in the Western US," data is shown confirming that Carlsbad is impacted by VOCs from oil and gas activity in the Permian. This further warrants the implementation of the strongest suites of controls at amine units and associated gas flares.

NOx is a visibility-impairing pollutant of interest: We urge the agency to dispel the claim made by several operators that SO_2, not NOx, is the contaminant of interest for visibility impairment in various Class 1 Airsheds. Both pollutants contribute to visibility impairment and emissions of nitrogen oxides must be mitigated to make reasonable progress toward the national goal of restoring natural air quality conditions. Some operators claim that NOx emissions from these pieces of equipment are inconsequential for regional haze purposes, while numerous federal agencies and groups have maintained that reducing NOx is necessary for best reducing visibility-reducing haze.

Colorado State's IMPROVE website makes available a Particulate Matter and Haze Composition Browser (available at http://vista.cira.colostate.edu/Improve/pm-and-haze-composition/), in which there is a map of all Class I areas, with associated 2018 data of PM composition by day. The recent data found in this IMPROVE resource reinforces the importance of controlling NOx in improving visibility in Class 1 airsheds impacted by oil and gas – particularly as this industrial activity has been accelerating greatly in the past several years. As shown in the data for 2018 for Carlsbad Caverns (Figure 1), nitrates are a significant contributor to PM in the winter months.

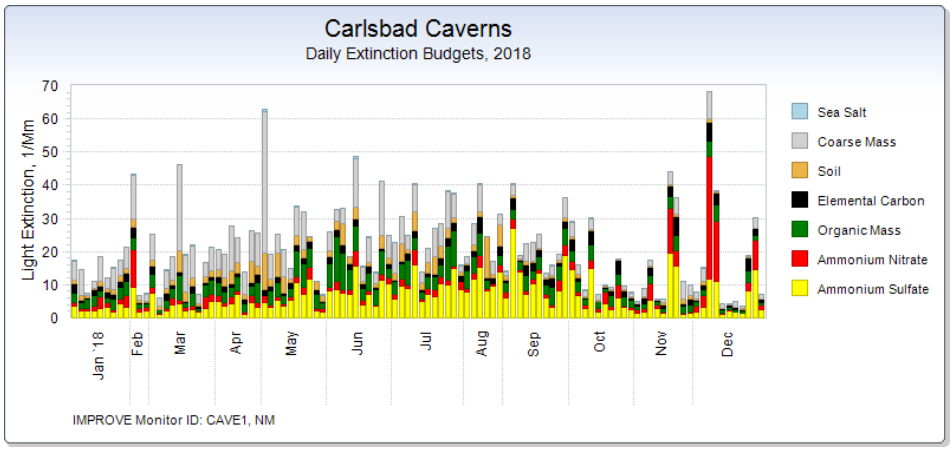


Figure 1.

Moreover, EPA's 2019 Regional Haze Guidance specifies that a state may use a number of screening tools and New Mexico's Q/d approach is a recognized screening methodology that reflects emissions of both SO2 and NOx.

Additional facilities that warrant reduction requirements: The agency's 10 lb/hr and 5 tpy criteria leaves out a wide array of facilities and equipment which contribute significantly to regional haze. In some cases, the agency did not require four-factor analysis for all units at a plant that had PTE greater than these thresholds (such as Units 7 and 8 at Kutz Canyon Gas Plant) - even though the company submitted other four-factor analyses for other units at the same facility.

NPCA has analyzed facilities not identified by NMED as being required to submit four-factor analyses (Figure 2). We have detailed the findings below, including the number of like sources and emissions and emission rate equivalents. In all, we assessed 62 additional facilities, with NOx emissions greater than 50 tpy. The NOx emissions from these 62 additional facilities total 10,711 tons per year according to the 2019 emissions NMED data. Within these 62 facilities, are 209 Lean Burn RICE units (Figure 3):

- 134 Lean Burn RICE units have NOx limits that equate to values greater than 1.0 gr/hp-hr.
- 69 Lean Burn RICE units have NOx limits that equate to values greater than 1.5 gr/hp-hr.
- 17 Lean Burn RICE units have NOx limits that equate to values greater than 2.0 gr/hp-hr.

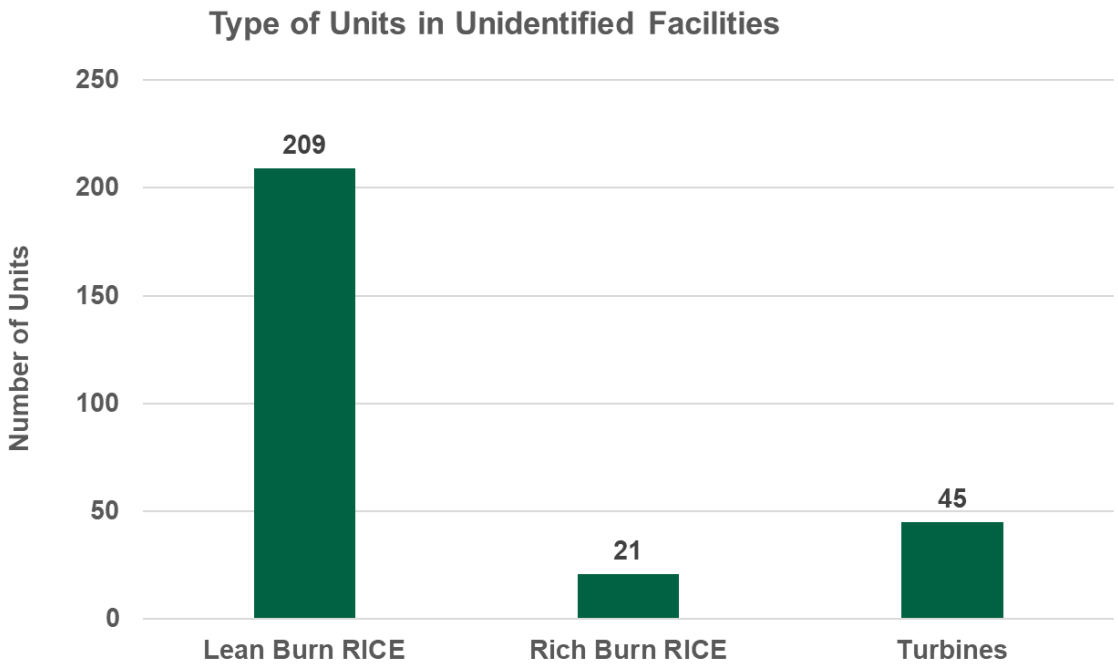


Figure 2.

As discussed above, emission reduction controls such as LEC and SCR are cost effective controls and can be used at these units to achieve NOx limits that equate to 0.15 to 2 g/hp-hr. with a NOx removal efficiency ranging from 87% to 95%. NPCA recommends NMED require a four-factor analysis of any Lean Burn RICE with equivalent NOx emission rates greater than 1.0 gr/hp-hr.

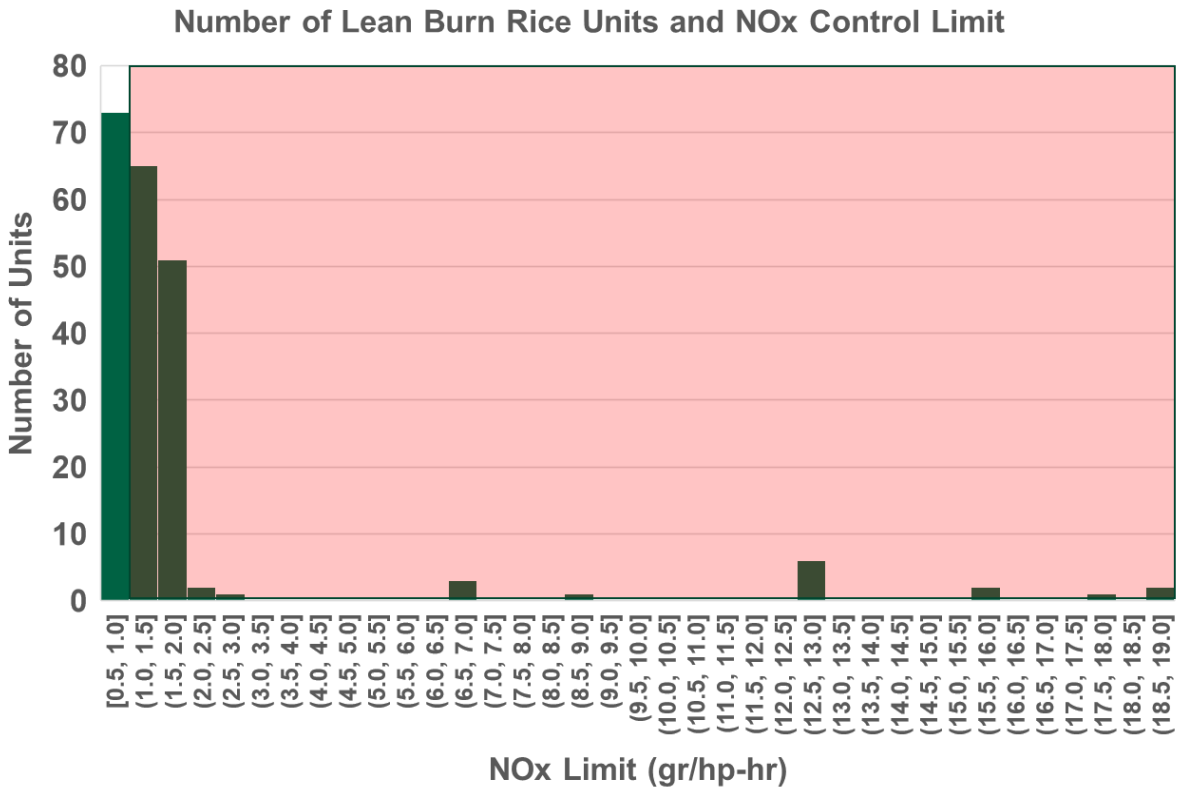


Figure 3.

In addition, we identified 21 Rich Burn RICE units at the 62 facilities not selected by NMED for a four-factor analysis. Of these Rich Burn RICE units, 17 have NOx limits that equate to 1.0 gr/hp-hr (Figure 4). Controlled NOx emission rates from 0.3 to 1.6 g/hp-hr. can be achieved using NSCR with a NOx removal efficiency ranging from 90% to 98%. Given the extremely favorable cost effectiveness of NSCR, NPCA recommends NMED require a four-factor analysis for any Rich Burn RICE with equivalent NOx emission rates greater than 1.0 gr/hp-hr.

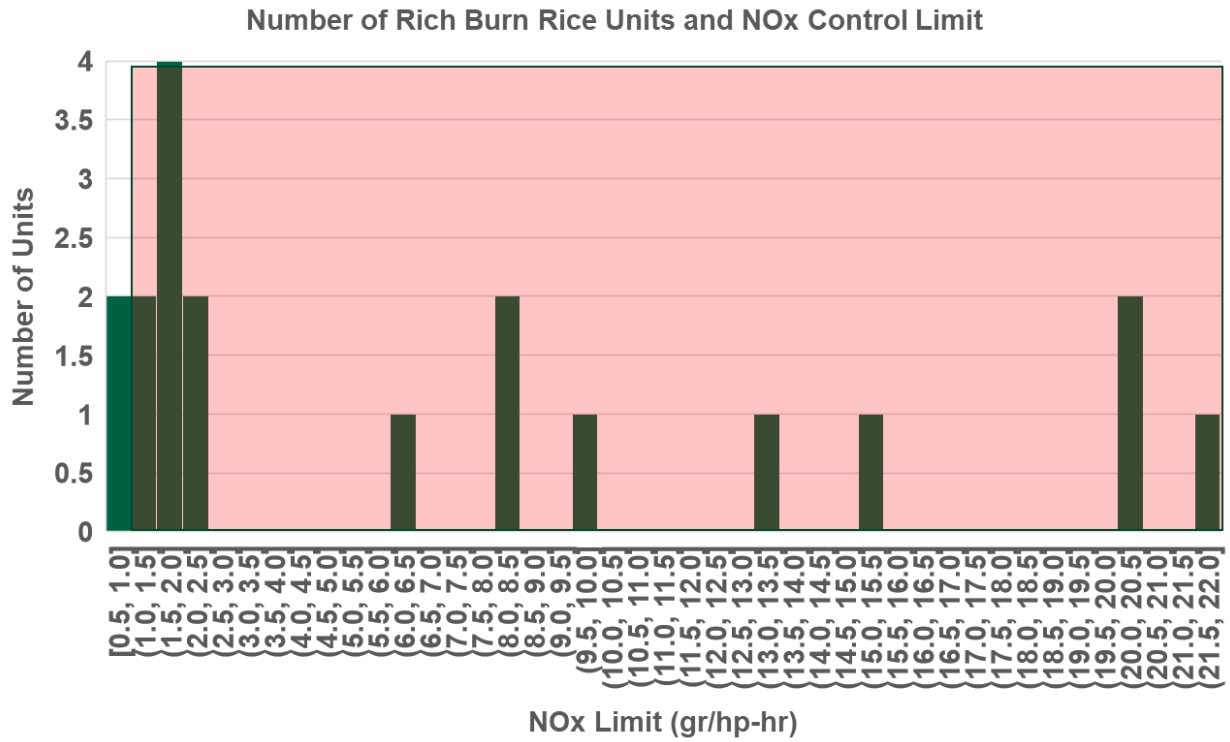


Figure 4.

Lastly, NPCA identified 45 turbines at compressor stations not selected for a four-factor analysis by NMED. Of them, 43 turbines have NOx limits higher than 15 parts per million (ppm) (~0.06 lb/MMBtu) (Figure 5), which reflects a controlled NOx emissions rate achievable with Dry Low NOx Combustors (DLNC) such as SoLoNOx or with SCR. NPCA recommends NMED require a four-factor analysis of these 45 gas turbines with equivalent NOx emission rates greater than 15 ppm.

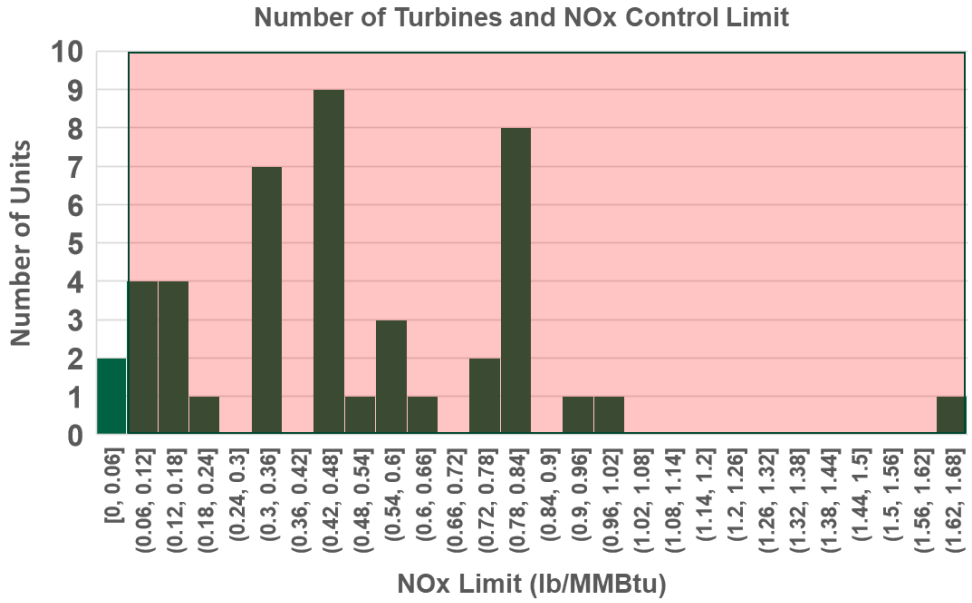


Figure 5.

In closing, we greatly appreciate the opportunity to work with New Mexico Environment Department, and welcome any questions and discussion regarding the attached comments and next steps to ensure the New Mexico Regional Haze Plan results in significant improvements to the visibility at our treasured Class I landscapes and across our communities.

Thank you,

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Assessment of Cost Effectiveness Analyses for Controls Evaluated Four – Factor Analyses for Oil and Gas Facilities For the New Mexico Environment Department's Regional Haze Plan for the Second Implementation Period

July 2, 2020

Prepared for National Parks Conservation Organization

Prepared by:

Vicki Stamper & Megan Williams

Executive Summary

In a March 2020 report on reasonable progress controls for several sources in the oil and gas sector, the authors provided general four-factor analyses of regional haze pollution control options for five source categories in the oil and gas industry, including natural gas-fired engines, combustion turbines, boilers, heaters, diesel-fired engines, and flaring and incineration.[1] That report identified regional haze pollution control options that are cost-effective and have been required by state and local air pollution control agencies through adaptation of emission limitations requiring retrofit of pollution controls for most of these source categories. For example, the report showed that, for natural gas-fired reciprocating internal combustion engines (RICE), cost effective controls include replacing engines with electric compressors, use of nonselective catalytic reduction (NSCR) at rich burn RICE, and use of low emissions combustion (LEC) or selective catalytic reduction (SCR) at lean burn RICE.[2] For natural gas-fired combustion turbines, the report found that the installation of dry low NOx combustion or the use of SCR (or in combination with dry low NOx combustion) is cost effective.[3] And for natural gas-fired heaters and boilers, the use of ultra-low NOx burners and/or SCR were found to be cost effective.[4] We refer the New Mexico Environment Department (NMED) to the March 2020 NCPA Oil and Gas Four-Factor Report for consideration in deciding the pollution controls to require of the New Mexico oil and gas sources for which NMED requested four-factor analyses.

In this document, we provide more specific comments on the cost of controls in the four-factor analyses submitted by oil and gas companies to NMED. The document is organized to provide comments on the facilities' four-factor analyses in order of magnitude of each facilities' "Q/d" value based on 2014 emissions. In the last sections of this document, we provide comments on two additional sources for which NMED did not request four-factor analyses but for which NPCA requested that NMED evaluate based on the facilities' Q/d—the Corona Compressor Station and the Empire Abo Gas Plant. And in the very last section, we provide comments on the four-factor analyses and control options for SO_2 emissions from amine units and flaring including startup, shutdown, malfunction emissions. Specifically, this report provides comments on the company cost analyses and/or provides cost analyses on the listed emission units at the following gas compressor stations and gas processing plants in New Mexico.

[1] *See* National Parks Conservation Association (NPCA) Report Entitled Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, and Flaring and Incineration, prepared by Vicki Stamper and Megan Williams, March 6, 2020 {hereinafter referred to as March 2020 NPCA Oil and Gas Four-Factor Report"].
[2] *Id.* at 10-57.
[3] *Id.* at 61-90.
[4] *Id.* at 116-146.

Emission Units and Facilities Evaluated in this Report

Plant	Units	Type of Emission Unit
Enterprise Chaco Gas Plant	17, 18, 35, 36, & 37	Gas Turbines
	12, 13, 14	2SLB RICE
DCP Eunice Gas Plant	17A, 18A, & 19A, 25A & 26A	Gas Turbines
	31	Amine Unit/SRU incinerator
IACX Bitter Lake Compressor Station	C-891 & C-893	2SLB RICE
Targa Eunice Gas Plant	C-01 thru C-07, & C-09 thru C-12	2SLB RICE
	B-01 & B-02	Gas-fired Boiler
Targa Monument Gas Plant	C-01, C-02, C-04 through C-06, & C-28	2SLB RICE
	AM-01/F-03	Amine Unit/Flare
Targa Saunders Gas Plant	C-01 thru C-09	2SLB RICE
	G-01 thru G-03	4SRB RICE
	AM-10/I-01	Amine Unit/Incinerator
Artesia Gas Plant		Flares
Harvest Four Corners Kutz Canyon Gas Plant	1 thru 6, 19, & 20	Gas Turbines
	16, 17, & 18	2SLB RICE
EPNG Pecos River Compressor	A-01, A-02, & A-03	Gas Turbines
DCP Linam Ranch Gas Plant	29, 30, 31, & 32B	Gas Turbines
	6 thru 11	2SLB RICE
ETC Texas Pipeline Jal No. 3 Gas Plant	4A & 5A	2SLB RICE
Davis Gas Processing Denton Gas Plant	007	Amine Unit/Flare
El Paso Natural Gas Co Washington Ranch Storage Facility	A-01 & B-01	2SLB RICE
Enterprise Blanco C&D Compressor	T-C01, T-C02, & T-D01	Gas Turbines
Harvest Pipeline San Juan Gas Plant	1 thru 7	Gas Turbines
Oxy USA WTP Indian Basin Gas Plant	ES-06/07, 08/09, & 10/11	Gas Turbines
		Amine Units
Enterprise South Carlsbad Compressor	1 & 2	Gas Turbines
El Paso Natural Gas Co Blanco Compressor Station A	A1 thru A14	2SLB RICE
Transwestern Roswell Compressor Station No. 9	903 & 904	4SLB RICE
Transwestern Mountainair Compressor	701, 702, & 703	4SLB RICE
Transwestern Corona Compressor Station	801 & 802, 821 & 822	2SLB RICE
	821 & 822	4SRB RICE
Empire Abo Gas Plant		Sulfur Recovery/Incinerator

RICE Notes: 2SLB: Two-Stroke Lean Burn; 4SLB: Four-Stroke Lean-Burn; 4SRB: Four-Stroke Rich-Burn

In general, the facilities' four-factor analyses are addressed in the order given in the above table, except that amine units and acid gas flares are addressed collectively in Section XXIII at the end of this report.

One overarching control option that NMED should give serious consideration to for lean burn RICE is the electrification of these engines. As was demonstrated in the March 2020 NCPA Oil and Gas Four-Factor Report, electrification of RICE units used for gas compression can be very cost effective just considering the NOx removal benefits, in the range of $1,200-$2,800/ton of NOx removed.[5] And several other pollution control benefits would occur with electrification of engines. From the regional haze perspective, replacing fossil fuel-fired RICE with electric engines would also reduce other visibility-impairing pollutants formed by the engines including volatile organic compounds (VOCs) and, for diesel-fired engines, particulate matter and sulfur dioxide (SO_2). Further, there would be reduced emissions of VOCs from compressor blowdowns. In addition, electric engines would require less maintenance time and have fewer upsets, which would not only reduce high NOx emissions that occur due to startups, shutdowns, and malfunctions, but would also reduce flaring of gas during compressor engine downtime which will reduce VOCs, NOx and, if the gas is sour gas, SO_2. And, of course, the additional significant co-benefit of the reduction in fossil fuel-firing and the reduction in upsets/less maintenance is that greenhouse gases will be greatly reduced. As stated in the NPCA Oil and Gas Report, replacing five RICE engines at a compressor station with electric compressors could eliminate approximately 16,000,000 cubic feet per year of fugitive methane emissions, which along with the greenhouse gas reductions from not burning natural gas in the engines would reflect a reduction of about 12,000 tons per year of carbon dioxide (CO_2) equivalent emissions.[6]

While the analysis of the costs to electrify units in the March 2020 NCPA Oil and Gas Four-Factor Report did not include any costs to upgrade electricity to a facility if needed, there are options that NMED should consider to reduce costs of power upgrades. For example, if more than one facility is located nearby each other, the facilities could partner to bring and/or upgrade electricity to the facilities. In a review of permits for midstream oil and gas facilities on NMED's Emissions Analysis Tool website,[7] there are at least five natural gas processing plants with electric engines in the New Mexico portion of the Permian Basin: 1) Targa -Eunice Gas Processing Plant, 2) Transwestern - Roswell Compressor No. 9, 3) Occidental- South Hobbs Reinjection Compression Facility, 4) DCP – Zia II Gas Plant, and 5) Durango Midstream – Maljammer Gas Plant. NMED should explore whether there are options for these plants to either electrify more engines and/or partner with nearby facilities to enable any necessary electric utility upgrades to electrify currently gas-fired engines. In the northwest part of New Mexico, there are three facilities that are co-located and are actually considered to be one source for Title V purposes despite having different owners: Blanco A Compressor Station,

[5] *Id.* at 44.
[6] *Id.* at 45-46.
[7] https://eatool.air.net.env.nm.gov/aqbeatool/.

Blanco C&D Compressor Station, and San Juan Gas Plant.[8] These facilities are about 1 mile from the city of Bloomfield, so they are not very remote. There are several lean burn RICE that could be replaced with electric engines at these facilities. Given the significant regional haze benefits that could be realized with electrification of engines, NMED should consider these and other options to facilitate implementation of this highly effective control measure.

With respect to other, albeit less effective than electrification control measures that should be considered cost effective for the emission units in the above table, the revised and supplemental cost effectiveness analyses provided herein support the findings of the March 2020 NCPA Oil and Gas Four-Factor Report. First, nonselective catalytic reduction (NSCR) is extremely cost effective for rich burn RICE. Given how cost effective NSCR is and how effective the control is for reducing NOx emissions, NMED should request analyses for all rich burn RICE at the facilities that submitted four-factor analyses, even if those units have NOx emissions that fall below NMED's emission thresholds of 10 pounds per hour (lb/hr) or 5 tons per year (tpy). Installation of NSCR could be a very cost effective way to achieve additional, meaningful NOx reductions at midstream facilities in New Mexico.

With respect to lean burn RICE, low emissions combustion (LEC) and, where evaluated, selective catalytic reduction (SCR), is generally cost effective for lean burn RICE that are operated greater than 500-1,000 hours per year. While several of the four-factor submittals to NMED had very high cost effectiveness values for LEC, those cost effectiveness analyses were often improperly inflated for the reasons discussed herein, including the assumption of low baseline emissions by focusing on a single year of baseline emissions. A single year of operational data of a lean burn engine used in a gas processing facility may not reflect how the unit will operate on average over its lifetime. For example, Targa, indicated that "[w]ith regards to the engine usage, Targa attempts to use its engines uniformly but this does not mean equally on a calendar year basis."[9] If an engine operates less than 1,000 hours per year—consistently, from year to year—LEC may not be cost effective. However, generally, LEC is cost effective for the specific engine models analyzed and can achieve 80–90% NOx reduction and reduce NOx emission rates to 2 g/hp-hr and lower. In addition, SCR is also shown below to be cost effective for lean burn engines at the two plants that evaluated SCR for such engines (Roswell Compressor Station No. 9 and Jal No. 3 Gas Plant). Based on those cost analyses provided herein, SCR should also be considered a cost effective control for lean burn engines, with the capability to achieve 90% NOx reduction and NOx emission rates of 1 g/hp-hr. With respect to claims made about whether SCR can be effectively used at lean burn engines, we refer NMED to the May 21, 2020 report "Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines" that NPCA provided to NMED via a May 22, 2020 letter.

[8] *See* 2/16/2015 Title V Operating Permit No. P048-R3 for Blanco Compressor Station A at 3.

[9] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 6.

For gas-fired combustion turbines, combustion controls and SCR have been required as best available control technology for new gas-fired turbines that power compressors at compressor stations.[10] In addition, combustion controls and SCR have been retrofit to numerous combustion turbines in numerous instances, primarily at electric utility combustion turbines. In revised and supplemental cost analyses presented herein, SCR is shown to be cost effective for most of the combustion turbine evaluated. While several companies made claims of space constraints and retrofit difficulty for SCR, the fact that SCR has been retrofit to numerous existing combustion turbines, coal-fired boilers, refineries, and other emissions sources that were not originally designed with space for SCR indicates that retrofit difficulties can and have been overcome. NMED should not allow a company to ignore evaluation of SCR based on purported retrofit difficulty claims without getting a vendor analysis of retrofit options for this highly effective control. The revised and supplemental cost effectiveness analyses provided herein show that SCR is cost effective for most of the combustion turbines evaluated in the New Mexico oil and gas facility four-factor analyses, unless the turbine has consistently low levels of operation and a low level of baseline emissions (in which case NMED should consider capping operations or emissions as a regional haze control).

For amine units and associated acid gas incineration or flaring, an acid gas injection well with, at the minimum, a backup electric acid gas compressor is the minimum level of control of SO2 that should be required. In fact, NMED has required this suite of controls in some settlement agreements, according to information provided in the Targa Eunice Gas Plant and Monument Gas Plant four-factor analyses. For those locations at which an acid gas injection well may not work effectively, then a sulfur recovery unit along with an incinerator and acid gas scrubber should be used to most effectively control SO2 emissions. Any maintenance or upset that requires the flaring of the acid gas stream from an amine unit can be a significant source of SO2 emissions and thus redundancy of controls is key for reducing/eliminating SO2 emissions associated with amine units at gas sweetening plants.

Below, we provide comments on the cost analyses in the company submittals made to NMED and provide revised and/or supplement cost analyses for the emission units analyzed.

[10] *See*, e.g., January 9, 2019 Registration No. 21599 for Buckingham Compressor Station, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.

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I. Enterprise Field Services Chaco Gas Plant

The Enterprise Field Services (Enterprise) Chaco Gas Plant is a natural gas processing plant. NMED has described the plant process as follows:

> The function of the facility is to receive field natural gas, process the gas through removal of water, then extraction/separation of natural gas liquids (NGL) through a cryogenic process. NGL recovered are then treated to remove carbon dioxide and hydrogen sulfide. Recovered NGL is delivered to a pipeline for transport to fractionation facilities downstream. The facility compresses/pumps residue and sales natural gas for distribution through mainline natural gas pipelines.

3/1/2019 Statement of Basis for Title V Permit Significant Modification (Permit Nos. 1555-M6 (revisions through M6R2) and P116-R2M1 at 1.

According to the permit, the plant includes several 2-stroke and 4-stroke lean-burn RICE, several natural gas-fired turbines, a diesel generator, flares, and a heater.[11] In Enterprise's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- General Electric (GE) Frame 5 Turbines: Units 17 and 18
- Solar Mars T-15000 Turbines: Units 35, 36, and 37
- Clark TLA-10 2SLB SI-RICE Engines: Units 12, 13, and 14.[12]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tons per year (tpy), which is the criteria established by NMED to identify sources subject to four-factor analyses.[13] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

Enterprise used an 8.38% interest rate in the cost analyses for all the controls evaluated in its 4-factor analyses.[14] This is an unreasonably high interest rate for cost effectiveness analyses. EPA's Control Cost Manual indicates that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[15] The current bank prime rate is 3.25%.[16] The highest

[11] Title V Operating Permit P116-R2M1 for Chaco Natural Gas Processing Plant at A6 to A8.
[12] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 1-2.
[13] *Id.*
[14] *Id.* at Section 8.0 Supporting Documentation.
[15] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at:

the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[17] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. However, in a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[18] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. Enterprise's use of an 8.38% interest rate is unreasonably high and overstates the cost effectiveness of pollution controls evaluated in the four-factor analyses.

B. GE Frame 5 Turbines: Units 17 and 18.

Units 17 and 18 at the Chaco Gas Plant are 19,500 horsepower natural gas-fired turbines that were constructed in 1970 and 1971.[19] The units each have a NOx emissions limit of 78.5 lb/hr and 344 tpy.[20] For these units, Enterprise identified water or steam injection as viable combustion controls for NOx but claimed that dry low NOx combustors were not available for retrofit to these types of gas turbines.[21] Enterprise claimed that SCR installation was not possible for these gas turbines, due to the size estimates of the SCR.[22] Presumably, Enterprise is claiming issues of retrofit difficulty. There is no question that SCR is technically feasible for natural gas-fired combustion turbines, including those used at compressor stations.

1. Evaluation of Baseline NOx Emissions.

According to the company's cost analysis for water/steam injection, Unit 17 has an actual NOx emission rate of 29.15 lb/hr (54.7 ppm) and Unit 18 has an actual NOx emission rate of 29.15 lb/hr (48.7 ppm) based on 2016 stack test data.[23] These actual emission rates are much lower than the units' 78.5 lb/hr allowable NOx emission rates, so either the 2016 stack test data was not performed while the engines were operating at maximum capacity, or the allowable NOx

https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[16] https://www.federalreserve.gov/releases/h15/.
[17] https://fred.stlouisfed.org/series/DPRIME.
[18] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.
[19] Title V Operating Permit P116-R2M1 for Chaco Natural Gas Processing Plant at A6 to A8.
[20] *Id.* at A10.
[21] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant, Part 3 of zipped file available on NMED's Emission Analysis Tool, at pdf page 11.
[22] *Id.* at 2-4.
[23] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 82- to 8-3.

emission rates have been set unreasonably high. NMED should present information on the 2016 stack test data so the circumstances of the stack tests can be reviewed. In addition, NMED and Enterprise should review other stack tests for these units to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. For example, in the November 2007 Title V renewal application for the Chaco Gas Plant, the actual emission test results were listed for Unit 17 as 49.22 lb/hr when the unit was operating at 83% load and was listed for Unit 18 as 69.8 lb/hr when the unit was operated at 89% load.[24] In addition, test data from 1995 was also included in the November 2007 permit application which shows Unit 17 with a NOx emission rate of 78.7 ppm @15% oxygen (O_2) and 90.6 ppm @ 15% O_2 and Unit 18 with a NOx emission rate of 93.4 ppm @ 15% O_2 and 109.5 ppm @15% O_2.[25] Clearly, these actual emission rates from Enterprise's 2007 Title V permit application are significantly higher than the 29.15 lb/hr (48.7-54.7 ppm) NOx emission rates that the company's four-factor cost effectiveness analysis is based upon. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on an estimate of emissions expected in 2028 pursuant to EPA's regional haze guidance for the second implementation period.[26]

2. Evaluation of Water Injection and Steam Injection for NOx Control

As a result of assuming what appears to be unreasonably low NOx emission rates for current emissions from the GE Frame 5 turbines, Enterprise also assumed an unreasonably low level of NOx reduction in its cost effectiveness analysis of water injection and steam injection. Specifically, Enterprise only assumed a 15% NOx reduction from water or steam injection.[27] While Enterprise cites EPA's AP-42 emission factor documentation for the 15% control with water or steam injection, EPA's AP-42 states that such controls can achieve 60% or higher NOx removal.[28] EPA's 1993 Alternative Control Techniques Document (ACT) for NOx emissions from Stationary Gas Turbines, cited in EPA's AP-42 emission factor documentation, states that NOx rates in the range of 25 to 42 ppmv can be achieved with water or steam injection as gas-fired combustion turbines.[29] For the Frame 5 turbines installed at the Chaco Gas Plant which, based on the 1978 year of manufacture indicated in the Title V permit, were presumably Model MS5001P,[30] EPA's 1993 Gas Turbine ACT listed the uncontrolled NOx emissions as 142 ppmv, dry, at 15% O_2.[31] Thus, a reduction to 25-42 ppm with water or steam injection would equate

[24] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf page 11.
[25] *Id.* at pdf pages 14 and 15.
[26] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation period, at 29.
[27] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-3.
[28] EPA, AP-42 Emission Factor Documentation, at 3.1-6.
[29] *See* EPA. Alternative Control Techniques Document – NOx Emissions form Stationary Gas Turbines, EPA-453/R-93-007, January 1993, at 2-5 [hereinafter EPA 1993 Gas Turbine ACT].
[30] *See* https://www.ccj-online.com/3q-2012/special-report-the-venerable-frame-5-gas-turbine/.
[31] *See* EPA. Alternative Control Techniques Document – NOx Emissions form Stationary Gas Turbines, EPA-453/R-93-007, January 1993, at 2-3.

to a 70% to 82% reduction in NOx emissions with water or steam injection from EPA's listed uncontrolled NOx rate of 142 ppmv. If the uncontrolled emissions of Units 17 and 18 are truly in the range of 48.7 to 54.7 ppm as indicated in Enterprise's 4-Factor analyses (assuming this is parts per million by volume at 15% oxygen, which NMED should confirm) and that is a reasonable projection of NOx emission rates into 2028 despite prior emission tests that were much higher than these levels, it seems very likely that the water or steam injection could reduce NOx down to at least 25 ppmv @ 15% O_2, which would be a reduction in emissions of 56% at Unit 17 and of 50.7% at Unit 18. Thus, NMED must require that Enterprise evaluate water or steam injection for Units 17 and 18 assuming a 25 ppmv @ 15% O_2 NOx rate could be achieved.

With respect to the life assumed of water or steam injection, Enterprise only assumed a 15-year life of these controls.[32] Enterprise did not provide any justification for assuming such a short life of water or steam injection. As discussed in NPCA's March 2020 report, the life of water or steam injection should be the life of the combustion turbines. In NPCA's March 2020 report, we assumed a 25-year life of water or steam injection.[33]

In terms of Enterprise's costs for water injection or steam injection, the company's capital costs seem very high for the size turbines, based on a comparison to the 1999 Department of Energy (DOE) report entitled "Cost Analyses of NOx Control Alternatives for Stationary Gas Turbines," which is cited in several EPA and State documents on the costs of NOx controls at gas turbines.[34] In that 1999 DOE report, the costs of water or steam injection for a slightly larger gas turbine, a GE LM2500 turbine which is of 22.7 megawatt capacity or about 30,400 hp, the capital cost in 1999 dollars of water injection was estimated to be $1,083,175.[35] Although EPA's Control Cost Manual advises against escalating costs more than five years because it can lead to inaccuracies in price estimation,[36] just using the Chemical Engineering Plant Cost Indices between 1999 and 2018, the DOE's 1999 costs of water injection for a larger GE LM2500 gas turbine would increase to $1.67 million.[37] Using a different cost index specific to oil refineries, the Nelson-Farrar index, the 1999 costs of water injection increase from $1.0 million to $1.88 million as of 2016 (the most recent annual Nelson-Farrer cost index found online).[38] Yet,

[32] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 6-1.
[33] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 64.
[34] Bill Major, ONSITE SYCOM Energy Corporation, and Bill Powers, Powers Engineering, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, prepared for U.S. Department of Energy, November 5, 1999, available at: https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf [hereinafter "1999 DOE Report"].
[35] *Id.*, Appendix A at A-4.
[36] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.
[37] Based on multiplying the 1999 cost estimate for water injection from the 1999 DOE report by the ratio of the CEPCI indices for 2018 to 1999 (603.1/390.6).
[38] Based on multiplying the 1999 cost estimate for water injection from the 1999 DOE report by the ratio of Nelson-Farrar indices for 2016 to 1999 (2598.7/1497.2).

Enterprise's capital cost estimate for water injection at Units 17 and 18 was $6.6 million, more than three times the escalated capital costs from the 1999 DOE report based on either the CEPCI index or the Nelson-Farrar index. Thus, Enterprise's capital cost estimate of water injection for a smaller capacity gas turbine at Units 17 and 18 seems very high. Further, the inspection and operating costs of water injection, which Enterprise stated would be $1,238,327 per year,[39] are not explained or documented and seem unreasonably high. NMED must request more details and support for these cost estimates of water injection and steam injection at Units 17 and 18.

We addressed just some of these issues to revise Enterprise's cost effectiveness analyses to reflect 1) a 4.7% interest rate (instead of 8.38%), 2) a 25-year life of water or steam injection (instead of an assumed 15-year life), 3) a controlled NOx rate with water or steam injection of 25 ppmvd at 15% O_2, and 4) revising Enterprise's baseline emissions to reflect EPA's NOx rate for uncontrolled GE Frame 5 gas turbines of 142 ppmvd[40] and a controlled NOx rate of 42 ppmvd. With the revisions listed in items 1 through 3 above, Enterprise's cost effectiveness of water or steam injection reduction from approximately $107,000 to $149,000/ton of NOx removed to $24,500- $38,692/ton, and it is important to note that no changes were made to Enterprise's own seemingly high estimates for capital and operating costs of water or steam injection. Revising Enterprise's cost estimates to use EPA's uncontrolled NOx rate for the turbine models of 142 ppmvd and a controlled NOx rate of 42 ppmvd with water or steam injection (the least stringent NOx emission rate that EPA indicates can be met with the control), reduces cost effectiveness of these controls to $7,300-$10,500/ton. Again, these revisions do not reflect any changes to Enterprise's seemingly high capital and operating costs for water or steam injection.

In its identification of energy and non-air quality environmental impacts of compliance, Enterprise did not list water use as an adverse environmental impact, but it is an issue to be concerned with for water injection.[41] That is why dry low NOx combustion, if available (which Enterprise claims is not available for the Unit 17 and 18 turbine models) or SCR are more preferable choices for NOx control from gas-fired turbines in New Mexico.

[39] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 8-2 to 8-3.
[40] *See* EPA. Alternative Control Techniques Document – NOx Emissions form Stationary Gas Turbines, EPA-453/R-93-007, January 1993, at 2-3.
[41] *See* March 6, 2020 NPCA Oil and Gas Four-Factor Report at 67-68.

3. Evaluation of SCR for Units 17 and 18 Gas Turbines.

Enterprise did not evaluate SCR for the Units 17 and 18 gas turbines, stating that it was "not possible to install these units at the Chaco facility" due to "the amount of buffer space needed to maintain accessibility to equipment and to avoid compromising worker safety."[42] While the facility and gas turbines may not have been originally designed to have space to accommodate SCR, that is typically the case with most SCR retrofits. As such, there have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints. For example, for many large coal-fired power plants, SCR reactors have been elevated above the air preheaters. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new foundations to make way for the SCR reactor.[43] Thus, before NMED accepts a very brief claim of retrofit difficulty of SCR at any emissions unit being evaluated for reasonable progress controls, it is imperative that NMED ask Enterprise for a site plan and photos that show whatever space constraints are being claimed, and that NMED asks Enterprise to consult with SCR vendors for options for SCR installation at the gas turbines of Units 17 and 18. For Unit 18, a schematic of the unit provided in the 2007 Title V permit application shows an oil heat recovery unit labeled as "out of commission."[44] Perhaps extracting that heat recovery unit out of the unit would enable for the relocation of the stack and space for the SCR. Unit 17 is also shown as being equipped with a heat recovery unit[45] and it is not clear if that is still operating or whether it could also be removed to make room for an SCR installation. In addition, there may be other options for the location of the SCR system. Depending on the proximity of the gas turbines, it is possible that one SCR reactor could be used by both Units 17 and 18, which would reduce costs and potentially be easier to install at the site. NMED must require all possibilities for SCR installation be evaluated and documented by Enterprise. The state must not simply discount this highly effective NOx control based on a claim of some retrofit difficulty.

In terms of the costs of SCR control, NPCA's March 2020 Oil and Gas Four-Factor Report showed the cost effectiveness in 1999 dollars for SCR achieving about 90% NOx reductions would range from $2,000/ton to $3,400/ton for a 5 MW combustion turbine (~6800 hp engine) depending on the operating capacity factor, and costs decrease for larger turbines like Units 17 and 19 which are approximately 19,500 hp engines.[46] For much larger combustion turbines of 75 MW

[42] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-4.
[43] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, available at https://www.onepetro.org/conference-paper/SPE-66501-MS.
[44] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf page 16.
[45] *Id.*
[46] *See* NPCA March 2020 Oil and Gas Four-Factor Report at 75.

generating capacity (~100,500 hp), cost effectiveness of SCR was significantly lower in the range of $560-$850/ton depending on operating capacity factor.[47]

To get an idea of the costs for SCR at Units 17 and 18 in current dollars, one can use EPA's SCR cost spreadsheet made available as part of EPA's Control Cost Manual.[48] While the EPA SCR cost spreadsheet was not specifically designed for simple cycle gas combustion turbines, it can be modified to estimate SCR cost for gas-fired combustion turbines. It seems likely that this EPA cost spreadsheet for boilers will overestimate the cost of SCR for natural gas-fired combustion turbines. This is because gas turbines, particularly those used in power generation, are routinely equipped with SCR systems, and for simple cycle gas turbines, the SCR systems are typically placed in an enclosure attached to the combustion turbine exhaust.[49] Boilers are not as commonly equipped with SCR compared to natural gas combustion turbines, and the SCR placement is more complicated with its placement usually between the economizer and air preheater and upstream of pollution control equipment. This EPA SCR cost spreadsheet is based on cost assumptions from the Integrated Planning Model (IPM) and those costs are, in turn, based on actual SCR retrofit costs for boilers.[50] Because SCR systems are more commonly applied at gas combustion turbines, especially those used in power generation (including simple cycle turbines) and because SCR installation at a simple cycle combustion turbine is often more straightforward than at a boiler, the EPA SCR cost spreadsheet likely overestimates the cost of SCR for a natural gas-fired combustion turbine. Thus, to generate a more current cost estimate of SCR for the natural gas-fired combustion turbines of Units 17 and 18 at the Chaco Gas Plant, EPA's SCR cost spreadsheet was also used to estimate SCR cost effectiveness.

For this analysis, Enterprise's claimed baseline NOx emission rates of 54.7 ppm and 48.7 ppm for Units 17 and 18, respectively, were used. These are assumed to be reflective of ppm by dry volume at 15% oxygen. As previously discussed, NMED should ensure that this 2016 test data reflects operations at maximum operating capacity and ensure that these emission rates are a reasonable projection of NOx emissions as of 2028, especially given that past NOx emission rates have been identified as significantly higher than these NOx rates. The company's actual NOx rates were converted to lb/MMBtu emission rates using a conversion formula from EPA's

[47] *Id.*

[48] While this spreadsheet was not identified to be used with natural gas-fired combustion turbines, as EPA states that its use is for boilers fired by coal, fuel oil, or natural gas with heat input greater than 250 MMBtu/hr or generating capacity greater than or equal to 25 MW, the spreadsheet can be used to estimate SCR capital and operations costs for any fossil fuel-fired unit as long as the necessary input data is available. In fact, it has been utilized by several oil and gas facilities in their four-factor analyses to NMED.

[49] *See*, e.g., Managing the Catalysts of a Combustion Turbine Fleet, Power, April 30, 2012, under 2. Typical simple cycle SCR. Available at https://www.powermag.com/managing-the-catalysts-of-a-combustion-turbine-fleet/.

[50] *See* Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, SCR Cost Development Methodology, January 2017, at 1, available at https://www.epa.gov/airmarkets/ipm-v6-emission-control-technologies-attachment-5-3-scr-cost-development-methodology.

1993 Gas Turbine ACT.[51] Enterprise's ppm NOx baseline rates thus were converted to 0.22 lb/MMBtu for Unit 17 and 0.20 lb/MMBtu for Unit 18. With this data, the authors input unit-specific information into EPA's SCR cost spreadsheet to estimate cost effectiveness of SCR at Units 17 and 18, including the altitude of the site listed in the 2007 Title V permit application of 6,020 feet and the exhaust gas temperature of 766 degrees Fahrenheit.[52] Two different SCR control levels were assumed: approximately 70% control to achieve a 15 ppmvd NOx rate and a 90% control efficiency to achieve approximately a 5 ppmvd NOx emission rate. In an analysis of SCR cost effectiveness from an uncontrolled gas turbine, NESCAUM estimated that a 15 ppmvd NOx rate reflective of 90% NOx control (from uncontrolled NOx rates) could be achieved with SCR.[53] As stated above, the 2016 baseline emission rates assumed by Enterprise are much lower than worse case NOx rates, and a 15 ppmvd limit only reflects 70% control across the SCR, when such controls can achieve 90% or greater NOx reduction. Thus, two levels of NOx emission reduction were assumed to reflect a low and a high level of NOx reduction with the SCR. The heat value of the fuel and hourly heat input for Units 17 and 18 identified in Part 3 of Enterprise's 2007 Title V permit application (i.e., 1,245 Btu/standard cubic feet and 181 MMBtu/hr)[54] were assumed to reflect current operations at the units. With Enterprise's 2016 actual annual NOx emissions and its reported ppm NOx emissions and the reported heat value of the fuel, actual annual gas consumption rates were estimated for each unit for input into the SCR cost spreadsheet. Capital costs were annualized applying a cost recovery factor using a 4.7% interest rate and a 25-year life which EPA has identified as typical for SCR systems used at industrial boilers.[55] Last, two different reagent types were evaluated: 29% aqueous ammonia and 50% urea solution. Urea was evaluated due to concerns raised by Enterprise in the use of ammonia as a reagent because, with urea used as a reagent, the concerns from hazards of using pressurized ammonia do not apply. The results of these analyses are provided in Table 1 below.

[51] *See* EPA, Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993, Appendix A which has conversion equations for natural gas-fired combustion turbines.
[52] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf pages 12 and 13.
[53] NESCAUM 2000 Status Report at III-21 through III-24 and at III-40 (see references 11, 16, 9, 14, and 15).
[54] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf pages 11-12.
[55] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

Table 1. Cost Effectiveness of SCR at Chaco Gas Plant Units 17 and 18 GE Frame 5 Gas Combustion Turbines, Using EPA's SCR Cost Calculation Spreadsheet for Boilers

Unit	Assumed NOx Removal Efficiency with SCR	Capital Cost of SCR (2018 $)	Annual O&M Costs with 29% Ammonia	Annual O&M Costs with Urea	NOx Removed from 2016 Baseline, tpy	Cost Effectiveness of SCR with Ammonia (2018 $), $/ton	Cost Effectiveness of SCR with Urea (2018 $), $/ton
17	72%	$5,725,135	$95,677	$125,129	79	$6,264	$6,638
17	90%	$5,725,135	$100,385	$137,200	98	$5,059	$5,433
18	70%	$5,725,135	$110,586	$144,582	91	$5,591	$5,965
18	90%	$5,725,135	$116,197	$159,905	117	$4,396	$4,771

The cost estimates of SCR based on EPA's boiler SCR cost spreadsheet project costs for SCR that are significantly lower than Enterprise's water or steam injection capital cost estimates, which were projected to range from $6.6 to $8.7 million, as well as the company's annual operating cost estimates, which ranged from $1.2 to $1.8 million per year.[56] Given that SCR can achieve much higher levels of control at much lower costs than water or steam injection, NMED must require Enterprise to more fully evaluate the ability to install SCR at Unit 17 and/or 18. Ninety percent control should be readily achievable with SCR at these units to meet a NOx emission rate of 5 ppmvd (0.02 lb/MMBtu). Before allowing Enterprise to dismiss SCR due to claims that it is not feasible to locate one or more SCR reactors at Units 17 and 18, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at Units 17 and 18, including any potential options for a shared SCR system between Units 17 and 18 if such options exist. SCR can be a very effective method for reducing NOx emissions from the Units 17 and 18 gas turbines and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for Units 17 and 18 at the Chaco Gas Plant.

C. Solar Mars T-15000 Turbines

Units 35, 36, and 37 at the Chaco Gas Plant are 15,000 horsepower natural gas-fired Solar Mars T-15000 combustion turbines that were constructed in 1996.[57] The units each have a NOx emissions limit of 76.2 lb/hr and 333.6 tpy.[58] For these units, Enterprise identified dry low NOx combustors made by the turbine manufacturer ("SoLoNOx") as a viable control technology, but claimed that SCR was not possible for these turbines due to retrofit difficulty; namely, due to the size estimates of the SCR.[59] As previously discussed, there is no question that SCR is

[56] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 8-1 to 8-3.
[57] Title V Operating Permit P116-R2M1 for Chaco Natural Gas Processing Plant at A7.
[58] *Id.* at A11.
[59] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-4.

technically feasible for natural gas-fired combustion turbines, including those used at compressor stations.

1. SoLoNOx at Units 35, 36, and 37

Enterprise evaluated SoLoNOx for the Solar Mars turbines of Units 35, 36, and 37, stating that it could reduce NOx concentrations down to 15 ppmv which reflects 85-88% NOx reduction efficiency from the 2016 stack test data that Enterprise assumed as baseline emissions.[60] NMED must ensure that the 2016 stack test data reflect actual emissions from the units and expected actual emissions from the units in 2028.

Enterprise's cost estimates for SoLoNOx at Units 35, 36, and 37 are based on vendor quotes from Solar Turbines.[61] Enterprise then determined cost effectiveness of SoLoNOx controls to meet a 15 ppmv NOx emissions rate, using an interest rate of 8.38% and an assumed life of controls of 20 years.[62] As previously discussed, a 4.7% interest rate is more reflective of current and likely near future interest rates. In terms of the life of SoLoNOx controls, the combustors should last the life of a combustion turbine, which is at least 25 years. Thus, to more accurately reflect cost effectiveness for the SoLoNOx controls at Units 35, 36, and 37, Enterprise's cost effectiveness calculations were revised to reflect a 4.7% interest rate and a 25-year life of controls. The revised costs are reflected in Table 2.

Table 2. Revised Cost Effectiveness of SoLoNOx at Units 35, 36, and 37 of the Chaco Gas Plant, to Reflect a 4.7% Interest Rate and a 25 Year Life

Unit	Enterprise's Total Annual Costs of SoLoNOx (at 8.38% Interest and 20-Year Life)	Enterprise's Cost Effectiveness at 8.38% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25-Year Life
35	$715,215	$6,800/ton	$512,744	$4,875/ton
36	$688,967	$6,668/ton	$495,494	$4,796/ton
37	$693,345	$9,434/ton	$498,371	$6,781/ton

Thus, SoLoNOx at Units 35, 36, and 37 should be considered much more cost effective than reflected in Enterprise's cost analysis.

[60] *Id.* at 2-2.
[61] *Id.* at 3-2.
[62] *Id.* at 8-4 through 8-6.

2. SCR at Units 35, 36, and 37

As with Units 17 and 18, Enterprise did not evaluate SCR for Units 35, 36, and 37, claiming it was "not possibly to install these units at the Chaco facility" due to "the amount of buffer space needed to maintain accessibility to equipment and to avoid compromising worker safety."[63] For the reasons discussed above in Section I.B.3, NMED must request more information and documentation before allowing Enterprise to dismiss SCR due to claims that it is not feasible to locate one or more SCR reactors at Units 35, 36, and 37. NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at Units 35, 36, and 37, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions from the Units 35-37 gas turbines and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for Units 35-37 at the Chaco Gas Plant.

There are two options for the evaluation of cost effectiveness of SCR at Units 35, 36 and 37: One is to consider SCR as a control option without SoLoNOx installed. A second option is to consider SoLoNOx plus SCR as the maximum achievable reductions in NOx emissions. As discussed in the NPCA March 2020 Oil and Gas Four-Factor Report, SCR has recently been proposed to be installed at several compressor stations.[64] Once such compressor station is the Buckingham Compressor station to be located in Virginia. That compressor station was proposed to be constructed with Solar Mars combustion turbines equipped with SoLoNOx and SCR to achieve a NOx emission rate of 3.75 ppmv @ 15% oxygen.[65] SCR installed along with the SoLoNOx combustion control could achieve 96 to 97% reduction in NOx emissions from Units 35, 36, and 37. However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as best available control technology (BACT) or Lowest Achievable Emission Rate (LAER) for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[66]

To get an idea of the costs for SCR at Units 35, 36, and 37 in more current dollars, we used EPA's SCR cost spreadsheet made available as part of EPA's Control Cost Manual. Two different costs analyses were completed for these comments: 1) SCR plus SoLoNOx to achieve a 3.75 ppmv NOx rate and 2) SCR by itself to achieve 15 ppmv. The costs analyses were based on the

[63] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-4.
[64] NPCA March 2020 Oil and Gas Four-Factor Report at 89.
[65] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.
[66] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.

use of a 50% urea solution as the reagent. As shown in Table 1 above, if a 29% aqueous ammonia reagent is used, the cost effectiveness will be lower than if urea is used – thus, these cost estimates reflect a worst case estimate. The company's actual NOx rates and the emission limits evaluated were converted to lb/MMBtu emission rates for input into EPA's SCR spreadsheet using a conversion formula from EPA's 1993 ACT for Gas Turbines.[67] With this data, unit-specific information was input into EPA's SCR cost spreadsheet to estimate cost effectiveness of SCR at Units 35-37, including the altitude of the site listed in the 2007 Title V permit application of 6,020 feet and the exhaust gas temperature of the turbines of 907 degrees Fahrenheit.[68] The heat value of the fuel and hourly heat input for Units 35-37 identified in Part 3 of Enterprise's 2007 Title V permit application (i.e., 900 Btu/standard cubic feet[69] and 91.2 MMBtu/hr)[70] were assumed to reflect current operations at the units. With Enterprise's 2016 actual annual NOx emissions and its reported ppm NOx emissions and the reported heat value of the fuel, actual annual gas consumption rates were estimated for each unit for input into the SCR cost spreadsheet. Capital costs were annualized applying a cost recovery factor using a 4.7% interest rate and a 25-year life which EPA has identified as typical for SCR systems used at industrial boilers.[71] To determine cost effectiveness of SoLoNOx plus SCR, the revised annualized costs of SoLoNOx at a 4.7% interest rate and a 25 year life were added to the costs of SCR to reduce NOx emissions from 15 ppmv to 3.75 ppmv. The results of these analyses are provided in Table 3 below.

Table 3. Cost Effectiveness of SCR Plus SoLoNOx at Chaco Gas Plant Units 35, 36, and 37 Solar Mars T15000 Turbines to Reduce NOx to 3.75 ppmv, Using EPA's SCR Cost Calculation Spreadsheet with Urea Reagent (2018 $)

Unit	Revised Total Annual Costs of SoLoNOx (at 4.7% Interest and 25-Year Life)	Capital Cost of SCR to Reduce NOx from 15 ppmv to 3.75 ppmv	Annual O&M Costs of SCR	Total Annual Costs of SCR	Total Annual Costs of SoLoNOx Plus SCR	NOx Reduced with SoLoNOx and SCR, tpy	Cost Effectiveness of SoLoNOx plus SCR, $/ton
35	$512,744	$3,666,834	$53,222	$308,349	$821,093	115.9	$7,082/ton
36	$495,494	$3,666,834	$53,361	$308,488	$803,982	114.2	$7,039/ton
37	$498,371	$3,666,834	$50,409	$305,536	$803,907	82.8	$9,704/ton

[67] *See* EPA, Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993, Appendix A which has conversion equations for natural gas-fired combustion turbines.
[68] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf page 24.
[69] Note that it is not clear that this reflects the high heating value of the fuel used at Units 35-37, especially given that the heat value of the fuel used at Units 17 and 18 was tested as having a much higher heat value of 1,245 Btu/scf. However, it is the heat value listed in the 2007 Title V permit application as specific to these units, so it is used here.
[70] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf page 24.
[71] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

Table 4. Cost Effectiveness of SCR at Chaco Gas Plant Units 35, 36, and 37 Solar Mars T15000 Turbines to Reduce NOx to 15 ppmv, Using EPA's SCR Cost Calculation Spreadsheet with Urea Reagent (2018 $)

Unit	Capital Cost of SCR	Annual O&M Costs	Total Annualized Costs of SCR	NOx Removed from 2016 Baseline, tpy	Cost Effectiveness of SCR, $/ton
35	$3,666,834	$104,172	$359,298	105.2	$3,416/ton
36	$3,666,834	$103,345	$358,472	103.4	$3,468/ton
37	$3,666,834	$85,814	$340,940	73.5	$4,642/ton

As shown by a comparison of Table 4 to Table 2, the costs of SCR to achieve the same level of NOx reduction as SoLoNOx at Units 35-37 is lower than the cost of SoLoNOx. As previously stated, costs were only provided for urea-based SCR. If aqueous ammonia was used as the reagent, the costs of SCR would be lower.

Clearly, SCR alone appears to be a more cost effective method to reduce NOx emissions from Units 35-37 by 85-88% control compared to SoLoNOx. Further, SCR used in combination with SoLoNOx can achieve the greatest reductions in NOx at these units. Thus, NMED must require further evaluation of the feasibility of installing SCR at Units 35, 36, and 37, including asking Enterprise to obtain vendor analyses of the site and feasibility of SCR retrofits.

D. Units 12, 13, and 14: Clark TLA-10 2-Stroke Lean Burn RICE

Units 12, 13, and 14 are two-stroke lean-burn RICE that were constructed in 1996, each with a capacity of 3,400 hp.[72] The units each have an hourly NOx limit of 49.7 lb/hr and an annual NOx limit of 218 tpy.[73] Enterprise states in its four-factor analysis that the NOx emissions from these units are calculated from stack test data from 4/18/1995.[74] This date seems possibly incorrect, or the permit is incorrect as it identifies the units as being constructed in 1/1/1996. Enterprise further states that the maximum hourly emission rate corresponds to a NOx exhaust concentration of 1,032 ppmv.[75] That is the extent of information provided on the actual NOx emissions from these units. NMED should request more information on the units' current hours of operation and actual NOx emissions.

[72] Title V Operating Permit P116-R2M1 for Chaco Natural Gas Processing Plant at A6.
[73] *Id.* at A10.
[74] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-5.
[75] *Id.*

1. Use of Low Emission Combustion Technology

Enterprise claims that the Clark TLA-10 engines are currently operating with "Clean Burn Technology (CBT)."[76] Yet, the stated maximum hourly NOx rate of 1,032 ppmv does not reflect the levels of NOx emissions typically expected with such low emission combustion (LEC) technology. This NOx concentration is equivalent to 14 grams per horsepower-hour (g/hp-hr).[77] Note, the hourly NOx permit limits for these units of 49.7 lb/hr, corresponding to a NOx limit of 7 g/hp-hr for each 3,400 hp engine.[78] And, in fact, the information provided as part of permit applications for the source, in 2007 and in 2016, indicate that these three units were initially retrofitted with the Controlled Rapid Burn (CRB™) systems from Diesel Supply Company, guaranteeing NOx emission rates of 7 g/hp-hr.[79] But even this controlled NOx emission level does not reflect the levels of NO_x emissions achievable with LEC technology. In order to effectively evaluate a company's assessment of LEC, a more precise definition of LEC technologies and associated achievable emission rates is needed.

EPA has examined source test data from large natural gas-fired lean burn engines and has affirmed that these data support an uncontrolled emission rate from these engines, generally, of 16.8 g/hp-hr.[80] More specifically, these source test data include individual data for three Clark TLA-10 engines with uncontrolled emission rates of 16 g/hp-hr and two Clark TLA-10 engines with uncontrolled emission rates of 7 g/hp-hr.[81] Even the permitted NOx limit of 7 g/hp-hr for the engines at the Chaco Gas Plant could therefore reflect an uncontrolled emission rate, although it appears these engines were retrofit with certain combustion modifications to reduce NOx emissions by 50% (i.e., CRB™ technology to reduce NOx emissions from 14 g/hp-hr to 7 g/hp-hr). Controlled NOx emission rates with LEC are typically much lower. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable

[76] *Id.* at 2-7.
[77] Using the following EPA conversion factors for uncontrolled lean burn engines (73 ppmv = 1 g/bhp-hr) and lean-burn engines controlled with LEC technology (73 ppmv = 1 g/bhp-hr), NOx emission rates would be 13.8 g/bhp-hr (assuming LEC control) or 14.1 g/bhp-hr (uncontrolled). *See* EPA-457/R-00-001 *Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques,* September 2000, p. 2-1, *available at*: https://nepis.epa.gov/Exe/ZyPDF.cgi/P100V343.PDF?Dockey=P100V343.PDF [hereinafter referred to as "EPA 2000 RICE Update"]. NOTE: this emission rate of 14 g/hp-hr appears to represent the uncontrolled emission rate, prior to retrofits to the units that reduced NOx emission by 50% and reflected in the permitted 49.7 lb/hr limit for these 3,400 hp engines (14 g/hp-hr * 3,400 hp / 453.6 g/lb = 100 lb/hr; 7 g/hp-hr * 3,400 hp / 453.6 g/lb = 50 lb/hr).
[78] Title V Operating Permit P116-R2M1 for Chaco Natural Gas Processing Plant at A10.
[79] *See,* Chaco Title V Renewal Permit P-116 Part 3 November 2007 *and* Chaco Permit 1555-M5 Significant Revision Application January 2016 *Emissions Support Data, Clark TLA-10 Compressor Engines, Retrofit Units 12—14*.
[80] *See* EPA Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call (October 2003) at 5, *available at:* http://www.valleyair.org/workshops/postings/2011/8-18-11-rule4702/R4702%20APPF.pdf.
[81] *Id*. at 6 and 7.

with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[82]

For reference, the following additional sources of information regarding NOx emission rates specific to Clark TLA model engines – both uncontrolled and with LEC technology – are provided here:

- EPA's 2000 RICE Update includes NOx emissions test data for specific engines, including Clark Model TLA-6, 2-stroke, lean-burn, 2,000 hp RICE retrofitted with LEC. According to EPA, six engines retrofitted by a third-party vendor had NOx emission rates ranging from 0.8–1.4 g/bhp-hr, with a mean of 1.0 g/bhp-hr.[83]

- An evaluation by a technical group for the Pipeline Research Council International looked at three of the most representative make / models of 2-stroke lean-burn compressor engines: (1) 2,250 hp Cooper GMVH-10; (2) 2,000 hp Clark TLA-6; and (3) 2,500 hp Cooper GMW-10. According to a technical report by the Ozone Transport Commission (OTC) describing this evaluation, "[t]he evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring."[84]

- In 2002, EPA collected data on emission rates of lean burn engines that have been retrofitted with LEC, including data from several state agencies for specific engine models.[85] Test results for 20 Clark TLA engines ranged from 0.4 to 2.9 g/hp-hr, with an average controlled NOx rate of 1.5 g/hp-hr.[86]

More generally, the 2012 OTC Report suggests that, "combustion related modifications have the potential to achieve from 60% to 90% reduction in NOx emissions [or, "an approximate range of NOx emissions rate of 3.0 g/bhp-hr to 0.5 b/bhp-hr"] from two-stroke lean-burn spark ignited reciprocating engines, depending upon the make/model configuration of the engine." Specifically, the 2012 OTC Report discusses the use of "layered combustion controls"

[82] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.
[83] EPA 2000 RICE Update at 4-8.
[84] Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, p. 24, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf [hereinafter referred to as "2012 OTC Report"].
[85] *See* EPA Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call (October 2003) at 15, *available at:* http://www.valleyair.org/workshops/postings/2011/8-18-11-rule4702/R4702%20APPF.pdf
[86] *Id.* Table 4.

in order to achieve emission rates at the lower end of this range, that include: improved airflow, improved fuel-air mixing, improved ignition, and upgraded controls.[87] According to the 2012 OTC Report, the higher emission rates in this range would tend to be more representative of situations where layered combustion controls packages have not been commercialized.[88]

More recently, EPA describes layered combustion (LC) as demonstrated control techniques for 2-stroke lean-burn engines, achieving a NOx emission rate of 0.5 g/hp-hr.[89] Specifically, EPA described LC as consisting of multiple combustion modifications, including: (1) high pressure fuel injection; (2) turbocharging; (3) a precombustion chamber; and (4) cylinder head modifications.[90]

Also, recently, EPA described LEC retrofit kits designed to achieve extremely lean air-to-fuel ratios – in order to minimize NOx emissions – as encompassing the following similar retrofit technologies:

- Redesign of cylinder head and pistons to improve mixing (on smaller engines)
- Precombustion chamber (on larger engines)
- Turbocharger
- High energy ignition system
- Aftercooler
- Air-to-fuel ration controller (AFRC)[91]

It is not entirely clear what specific combustion and LEC technologies are employed for the Clark TLA-10 engines at the Chaco Gas Plant. Enterprise states that these engines are currently operating with "Clean Burn Technology" and discusses that to generally mean the use of high energy ignition system, turbocharger, and AFRC technologies.[92] The Controlled Rapid Burn (CRB™) retrofit kits originally installed on Units 12–14 appear to include pre-chambers and high

[87] *Id.*
[88] *Id.*
[89] 2016 EPA Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS (Docket ID No. EPA-HQ-OAR-2015-0500), Appendix A at 5-5, *available at:* https://19january2017snapshot.epa.gov/sites/production/files/2015-11/documents/assessment_of_non-egu_nox_emission_controls_and_appendices_a_b.pdf [hereinafter referred to as "CSAPR TSD for Non-EGU NOx Emissions Controls"].
[90] *Id.* at 5-7.
[91] EPA, Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500-0508, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance, August 2016, Appendix A at 5-3, *available at:* https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0500-0508 [hereinafter referred to as "2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls"].
[92] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-7.

flow fuel valves.[93] However, the controls at these units are not achieving NOx emission levels commensurate with LEC.

EPA noted, in its 2000 Updated Information on NOx Emissions and Control Techniques for RICE, that "CleanBurn" is a trademark of Cooper Energy Systems, and that industry comments on its draft AP-42 emission factors for stationary internal combustion engines objected to a "clean burn" designation for that reason.[94] EPA's 1997 draft AP-42 section for stationary internal combustion sources defined "clean burn" engines as separate engine families (*i.e.*, distinct from other 2-stroke and 4-stroke lean-burn engines), equipped with "LEC precombustion chamber technology" and identified the following NOx emission factors for these distinct LEC-equipped "engine families":

> (1) 1.1 g/bhp-hr (2-stroke clean-burn engines); and
>
> (2) 0.5 g/bhp-hr (4-stroke clean-burn engines).[95]

EPA's 2000 RICE Update notes that, "[t]oday, many engine manufacturers refer to their engines equipped with precombustion chambers simply as "lean-burn engines"."[96] And EPA's final AP-42 section on natural gas-fired reciprocating engines clarified the term, as follows:

> Some lean-burn engines are characterized as clean-burn engines. The term "clean-burn" technology is a registered trademark of Cooper Energy Systems and refers to engines designed to reduce NOx by operating at high air-to-fuel ratios.[97]

A recent Interstate Natural Gas Association of America (INGAA) Report provides some information on Clark TLA engine stock components and retrofit modification / upgrade options.[98] Examples from this report include: upgrading stock turbocharger and stock intercooler systems; upgrading stock low pressure direct fuel systems to high pressure fuel injection and control systems; and upgrading controls for the stock fuel system.[99] Based on the

[93] *See* 5/12/95 Bid from Diesel Supply Company to El Paso Natural Gas Company for "converting your Clark TLA-10 engines at your CHACO plant." This bid is included in the Chaco Title V Renewal Permit P-116 Part 3 November 2007 *and* Chaco Permit 1555-M5 Significant Revision Application January 2016 *Emissions Support Data, Clark TLA-10 Compressor Engines, Retrofit Units 12—14*. *Also, see:* https://www.dieselsupply.com/.
[94] EPA 2000 RICE Update at p. 4-8.
[95] *Id. See discussion at* 3-9.
[96] *Id.* at 4-8.
[97] EPA AP-42 Chapter 3, Section 3.2 (July 2000) at 3.2-2, *available at:* https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf.
[98] INGAA, Report No. 2016-6, *Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOx Control for Natural Gas Transmission and Storage Compressor Drivers* (December 2017), *available at:* https://www.ingaa.org/File.aspx?id=33789.
[99] *Id. See, e.g.,* Table 6 at 18.

information in this report, Clark TLA model engines come equipped with a single turbo, an intercooler system, and a low pressure direct fuel system. The INGAA report evaluated controls for various regulatory scenarios that would achieve NOx emission levels in the 1–3 g/hp-hr range.[100]

LEC retrofit costs specific to Clark TLA model engines are reported in the INGAA report, ranging from $300–$600 per hp, for upgrades to the scavenging, intercooler, and fuel systems.[101] The INGAA report doesn't specify what year the cost data are from so we assume it reflects the timeframe of the report, or 2017$. Using these cost data, we can estimate the cost effectiveness of retrofitting Units 12, 13, and 14 at the Chaco Gas Plant. Retrofit costs for each 3,400 hp unit using INGAA's cost data would range from $1.02–$2.04 million, in 2017$. Using the Chemical Engineering Plant Cost Indices, these costs could increase to $1.08–$2.17 million, in 2018$.[102] It's not clear if operating costs are included in these estimates; to be conservative, annual operating costs of the LEC controls are assumed to be 15% of capital costs.[103]

The cost effectiveness of retrofitting these engines with LEC to meet a 2 g/hp-hr NOx emissions rate, based on the units' uncontrolled emission rate, is presented in the table below. The original retrofits to these units resulted in controlled NOx emission rates of 7 g/hp-hr possibly employing some of the upgrades associated with LEC. This analysis shows the cost effectiveness of an LEC retrofit that can achieve an emission level between 1–3 g/hp-hr based on current technologies and costs. The operating schedule for these engines at the Chaco Gas Plant is unknown but we present cost effectiveness for 8,000 operating hours per year since annual facility NOx emissions indicate that the units operated near capacity in 2016.[104] Note, this analysis uses an interest rate of 4.7%, reflective of current and likely near future interest rates.[105] Further note, the LEC controls are assumed to last 25 years, consistent with other cost effectiveness analyses submitted to NMED for LEC controls.[106]

[100] *Id.* at 23.
[101] *Id.*
[102] Based on multiplying the cost estimate from the 2017 INGAA report by the ratio of the CEPCI indices for 2018 to 2017 (603.1/567.5).
[103] This assumption is consistent with cost data provided for the October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, however it results in much higher O&M costs than those used in Targa's (Eunice, Monument, and Saunders Gas Plants) and Harvest Four Corners' (Kutz Canyon Gas Plant) four-factor analyses—which ranged from $40,000/yr to $100,000/yr—and than those used for ETC Texas Pipeline's Jal No. 3 Gas Plant, which assumed O&M costs would be 13% of capital costs.
[104] *See* NMED's Emissions Analysis tool, which reports 2016 NOx emissions of 2,258.9 tons per year, compared to total annual NOx PTE for the units evaluated in Enterprise's four-factor analysis for the Chaco Gas Plant of 2,342.8 tons per year (*see* Table 1 of the November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 1-1).
[105] As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.
[106] *See* 2019 Four-Factor Analyses for Roswell Compressor No. 9 and Jal No. 3..

Table 5. Cost Effectiveness of LEC at Uncontrolled Chaco Gas Plant Units 12, 13, and 14 to Reduce NO_x Levels to 2 g/hp-hr, Assuming a 4.7% Interest Rate and a 25-Year Life, 2018 $

Unit	Capital Cost of LEC to Reduce NOx from the Uncontrolled rate of 14 g/hp-hr	Annual O&M Costs (assume 15% of Capital Costs)	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (~85% NOx Reduction)	NOx Removed, tpy operating 8,000 hr/yr	Cost Effectiveness of LEC operating 8,000 hr/yr, $/ton
12	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	360	$659/ton–$1,319/ton
13	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	360	$659/ton–$1,319/ton
14	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	350	$659/ton–$1,319/ton

LEC at Units 12, 13, and 14 would be even more cost effective than what is shown if retrofits at these engines could meet even lower NOx emission levels, less than 2 g/hp-hr. Note, an analysis of individual upgrades at the units at the Chaco Gas Plant is not possible without knowing which specific LEC technologies are already employed to meet the permitted emission rate of 7 g/hp-hr and which additional possible upgrades could be installed to achieve even greater emissions reductions. NMED must ask for a list of specific LEC technologies employed at Units 12–14 and an evaluation of additional applicable LEC technologies for these units. NMED should require additional LEC retrofit techniques be evaluated in order to assess the cost effectiveness of further reducing NOx emissions from these engines to a level more in line with current LEC technology – i.e., emission levels in the 0.5–2 g/hp-hr range.

2. Use of SCR.

Enterprise did not evaluate SCR for Units 12, 13, and 14, primarily because it claimed that it was not possible to install SCR at these units due to space limitations.[107] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at Units 12, 13, and 14, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for Units 12-14

[107] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-6.

at the Chaco Gas Plant, particularly because Enterprise has not evaluated any other NOx reduction strategy for these units.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[108]

If Clean Burn or other low emissions technology is not a viable or cost-effective control for lean burn engines, SCR could possibly be a more cost-effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[109] In Section XX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[110] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

II. DCP Midstream – Eunice Gas Plant

The DCP Midstream Eunice Gas Plant is a natural gas processing plant located in Lea County, New Mexico. A NMED Statement of Basis for the plant's Title V permit describes the plant as follows: "The Eunice plant consists of an Inlet Receiving System, Amine Treater, Sulfur Recovery Plant, Inlet Compression, Dehydration, Cryogenic/Turbo Expansion Plant with External Propane Refrigeration, and product sales for Residue Gas, NGLs, and Condensate. Supporting systems and operations at the plant include Fuel Gas Systems, Instrument and Starting Air Systems, a Heat Medium (Hot Oil) System, Cooling Towers, Process Flare, Acid Gas Flare, and Drain Systems. Processing operations at the plant include chemical reaction processes, thermodynamic processes, and physical processes."[111] The plant separates heavier hydrocarbons that can be condensed into liquids (called "Natural gas liquids or NGLs" and removes impurities from the natural gas such as water, hydrogen sulfide (H2S) gas, and carbon dioxide gas.[112]

[108] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[109] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[110] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[111] NMED Statement of Basis – Narrative, Title V Permit, for Permit Nos. 0044-M-10-M10R6 and P086-R3, at 1.
[112] *Id.*

According to the permit, the plant includes several four-stroke lean-burn RICE, several natural gas-fired turbines, boilers, a heater, gas sweetening equipment (amine unit, sulfur recovery unit (SRU) incinerator, acid gas and SRU flares), and other emission units.[113] In DCP Midstream's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Solar Centaur Turbines: Units 17A, 18B, 19A, 25A, and 26A
- Amine Unit controlled by SRU Incinerator: Unit 31
- Startup, Shutdown, Malfunction (SSM).[114]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[115] The following provides a review of the company's four-factor analyses for the turbines. The analysis for the amine unit and SSM emissions is addressed in Section XXIII. below.

A. Interest Rate Used in Cost Analyses.

DCP Midstream used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[116] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[117] The current bank prime rate is 3.25%.[118] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[119] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[120] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable

[113] Title V Operating Permit P086-R3 for DCP Eunice Gas Plant at A6 to A8.
[114] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Eunice Gas Plant at 1-2.
[115] *Id.*
[116] *Id.* at Section 8.0 Supporting Documentation.
[117] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[118] https://www.federalreserve.gov/releases/h15/.
[119] https://fred.stlouisfed.org/series/DPRIME.
[120] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

B. Solar Centaur Natural Gas-Fired Combustion Turbines (Units 17A, 18B, 19A, 25A, and 26A).

The combustion turbines evaluated at the Eunice Gas Plant are Solar combustion turbines, model T-4002 of 3329 hp capacity (Units 17A, 25A, and 26A) and model T-4502 (Units 18B and 19A) of 3372 hp capacity.[121] These units were constructed between 1974 and 1986.[122] Units 18A and 19A are subject to a NOx emission limit of 165.85 ppmv at 15% O_2 and Units 25A and 26A are subject to a NOx limit of 158.76 ppmv at 15% O_2, pursuant to 40 C.F.R. Part 60, Subpart GG.[123] Under the terms of the permit, the units are also subject to the following hourly and annual emission limits of NOx.

Table 6. Limits from DCP Midstream Title V Permit for the Eunice Gas Plant Combustion Turbines[124]

Combustion Turbine Unit ID	NOx limit, lb/hr	NOx limit, tpy
17A	18.5	81.0
18B	23.0	100.9
19A	23.0	100.9
25A	18.5	81
26A	18.5	81

DCP Midstream evaluated two control options for these combustion turbines: Solar's SoLoNOx combustion system and SCR.

1. Baseline Emissions for Units 17A, 18B, 19A, 25A, and 26A.

DCP Midstream did not provide any specific data on actual emissions for the Solar Centaur combustion turbines in its four-factor analysis of controls. The company did state that its cost effectiveness analyses for SoLoNOx and SCR were based on 2016 turbine operating hours multiplied by the permitted potential to emit rate (lb/hr).[125] However, the company did not provide the operating hours or this calculation of 2016 emissions in its four-factor analysis. The company also provided analyses of cost effectiveness of controls "[u]sing the actual emissions testing data (NSPS KKKK) for these turbines, rather than [potential to emit]."[126] Yet, the company provided no data in its four-factor analyses as to what the actual emission testing results were. Further confusing the matter is that, based on a review of the permit, the turbines are not subject to NSPS KKKK. Instead, all of the units except Unit 17A are subject to

[121] Title V Operating Permit P086-R3 for DCP Eunice Gas Plant at A6 to A7.
[122] *Id.*
[123] *Id.* at A10.
[124] *Id.* at A9.
[125] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Eunice Gas Plant at 3-10, fn 13.
[126] *Id.*

NSPS Subpart GG, and the Title V permit does not identify Unit 17A as subject to either NSPS Subpart GG or Subpart KKKK.[127] A review of Title V permit application data for the Eunice Gas Plant on the NMED's Emissions Analysis Tool did not find any other emissions testing data available for these units.[128]

NMED must make available whatever test data is being relied on to reflect actual emissions of these five combustion turbines if NMED intends to rely on the cost effectiveness analyses provided in a footnote of DCP Midstream's four-factor analysis. NMED should present information on the test data so the circumstances of the stack tests can be reviewed. According to DCP Midstream's four-factor analysis, its 2016 emission inventory is based on its actual operating hours multiplied by its hourly NOx emission limit.[129] Given that this is how DCP Midstream reports actual emissions for the combustion turbines to NMED and in the absence of testing documentation to ensure that the test data DCP relies on for its alternative baseline analysis reflects actual emissions at all levels of operation of the combustion turbines, it seems most appropriate to use the data that DCP has been using for its emission inventory. NMED should require that DCP identify the operating hours of each unit that it has assumed for the combustion turbines.

2. Evaluation of SoLoNOx for Turbines at Units 17A, 18B, 19A, 25A, and 26A.

DCP Midstream states that SoLoNOx can achieve an "overall reduction efficiency of 70-80%...for the turbines located at this facility using this technology in comparison to permitted [potential to emit]."[130] NMED should request that DCP Midstream identify the NOx rate that Solar Turbines guarantees for each of the five turbines at Eunice Gas Plant. Specifying a NOx emission rate that can be met with SoLoNOx also would provide for a clear benchmark for comparison to SCR.

Based on assuming 70 to 80% reduction with SoLoNOx from the permitted ppmv NOx emission limits, it appears that DCP Midstream evaluated SoLoNOx to achieve NOx emission rates in the range of 31 ppmv to 50 pppmv at 15% O_2 at Units 17A, 18B, 19A, 25A, and 26A.[131] These seem like high emission rates expected with SoLoNOx, based on a review of emission limit data for combustion turbines in the EPA's RACT/BACT/LAER Clearinghouse which indicates SoLoNOx limits in the range of 15-25 ppmv. As another comparison, Enterprise evaluated SoLoNOx for the Solar Mars turbines at the Chaco Gas Plant and stated that SoLoNOx could reduce NOx concentrations down to 15 ppmv. Although Section 8.0 of DCP Midstream's four-factor analysis

[127] Title V Operating Permit P086-R3 for DCP Eunice Gas Plant at A5, Table 103.A.
[128] While Section 8.0 of the four-factor analysis for the Eunice Gas Plant has specific baseline NOx emission rates for the Linam Ranch Gas Plant combustion turbines, it does not have baseline NOx rates for the Eunice Gas Plant combustion turbines.
[129] *Id.* at 3-11.
[130] *Id.* at 2-4.
[131] This range of controlled ppmv NOx emission rates is based on assuming 70 to 80% reduction from the 158.76 ppmv NOx emission limit that Units 17A, 25A, and 26A and from the 165.85 ppmv NOx limit that Units 18B and 19A are subject to.

has cost data sheets for SoLoNOx indicating a NOx guarantee from Solar of 15 ppm, those cost data sheets pertain to the Linam Ranch Gas Plant rather than for the combustion turbines at the Eunice Gas Plant. For these reasons as well as completeness of the four-factor analysis of emissions controls for these units, NMED must collect more specific information on the NOx emission rates that DCP Midstream used in its SoLoNOx cost effectiveness analysis for the combustion turbines.

In terms of the life of SoLoNOx controls in the cost effectiveness analyses, DCP's analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[132] In the table below, we revised DCP Midstream's cost effectiveness analyses of SoLoNOx to take into account a longer lifetime of controls and a lower 4.7% interest rate.

Table 7. Revised Cost Effectiveness of SoLoNOx at Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant

Unit	DCP's Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	DCP's Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25-Year Life
17A	$264,731	$4,909/ton	$244,277	$4,530/ton
18B	$264,154	$3,578/ton	$243,700	$3,301/ton
19A	$264,154	$3,618/ton	$243,700	$3,338/ton
25A	$264,731	$5,186/ton	$244,277	$4,785/ton
26A	$264,731	$6,005/ton	$244,277	$5,542/ton

Thus, the cost effectiveness of SoLoNOx at Units 17A, 18B, 19A, 25A, and 26A are in the range of $3,300/ton to $5,542/ton to achieve 70-80% NOx reduction. However, if SoLoNOx can achieve 15-25 ppmv NOx emission rates at these units as has been permitted for other Solar turbine units with SoLoNOx, and as has been proposed in several four-factor analyses before NMED, then the NOx removal expected with SoLoNOx would be 84 to 91% and the controls would be even more cost effective than shown in the above table. The table below provides an estimate of the cost effectiveness of SoLoNOx if the controls could achieve 25 ppmv (~85% control) and 15 ppmv (~90% control).

[132] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

Table 8. Estimated Cost Effectiveness of SoLoNOx at Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant to Meet 25 ppmv NOx Rates and to Meet 15 ppmv NOx Rates.

Unit	Revised Total Annual Costs of SoLoNOx	Estimated NOx Reduced to Achieve 25 ppmv NOx Rate (~85% Reduction), tpy	Estimated NOx Reduced to Achieve 55 ppmv NOx Rate (~90% Reduction), tpy	Cost Effectiveness to Meet 15 to 25 ppmv NOx limit, $/ton
17A	$244,277	68.8	72.9	$3,352 - $3,549/ton
18B	$243,700	85.7	90.8	$2,684 - $2,842/ton
19A	$243,700	84.8	89.8	$2,714 - $2,874/ton
25A	$244,277	65.2	69.0	$3,541 - $3,749/ton
26A	$244,277	56.3	59.6	$4,100 - $4,341/ton

If SoLoNOx at Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant could meet more typical NOx limits with SoLoNOx of 15-25 ppmv, then the SoLoNOx controls would be even more cost effective than shown in DCP Midstream's four-factor analysis.

3. Evaluation of SCR for Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant.

Unlike Enterprise in its four-factor analysis of controls for the combustion turbines at the Chaco Gas Plant, DCP Midstream evaluated SCR as a technically feasible control option for the Solar Centaur gas combustion turbines of Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant. DCP Midstream used EPA's SCR cost spreadsheet made available with EPA's Control Cost Manual.[133] While the company presented printouts of the EPA SCR cost spreadsheet in Section 8.0 of its four-factor analysis, the printouts appear to be for the Linam Ranch Gas Plant and not the Eunice Gas Plant. NMED should request a printout of the pages of the SCR cost spreadsheet for Units 17A, 18B, 19A, 25A, and 26A of the Eunice Gas Plant so the inputs to the spreadsheet can be reviewed.

DCP Midstream only assumed 70% control could be achieved with SCR at Units 17A, 18B, 19A, 25A, and 26A, even though the company indicated that SCR could achieve up to 90% control.[134] As presented NPCA's Oil and Gas Four-Factor Report, NESCAUM assumed 90% control with SCR in its 2000 Status Report to control small gas turbines down to 15 ppmv.[135] Analyses of EPA's SCR cost spreadsheet for combustion turbines of similar size to Units 17A, 18B, 19A, 25A, and 26A shows that the spreadsheet's calculation of capital cost does not vary based on the NOx control efficiency assumed for the SCR, but that the direct operational expenses increase by

[133] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Eunice Gas Plant at 3-11.
[134] *Id.* at 2-6.
[135] NPCA March 2020 Oil and Gas Four-Factor Report at 74-75. *See also* NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15), available at http://www.nescaum.org/documents/nox-2000.pdf/view.

about 17.7%. Using this assumption, we revised DCP Midstream's SCR cost estimate to reflect the costs to achieve 90% NOx reduction, reflective of approximately a 15 ppmv NOx emission rate, along with using a longer life of the SCR of 25-years[136] and a 4.7% interest rate (instead of DCP's assumed 20-year life of SCR and 5.5% interest rate). The table below provides an estimated cost effectiveness of SCR to achieve 90% control at Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant.

Table 9. Estimated Cost Effectiveness of SCR to Achieve 90% Reduction (~15 ppmv NOx Rate) at Units 17A, 18B, 19A, 25A, and 26A (at 4.7% interest rate and 25-year life)

Eunice Gas Plant Unit #	DCP's Capital Cost of SCR	DCP's Annual Operational Costs of SCR[137]	Estimate of Revised DCP Annual Operational Costs of SCR to Reflect 90% Control[138]	Revised Annual Cost of SCR to Achieve 90% Control	NOx Emission Reductions at 90% Control, tpy	Cost Effectiveness of SCR to Achieve 90% Control
17A	$1,500,000	$149,435	$136,663	$239,914	72.87	$3,292/ton
18B	$1,500,000	$148,858	$138,195	$241,446	90.78	$2,660/ton
19A	$1,500,000	$148,858	$137,979	$241,230	89.79	$2,686/ton
25A	$1,500,000	$149,435	$135,696	$238,947	68.99	$3,463/ton
26A	$1,500,000	$149,435	$123,938	$227,189	59.58	$3,813/ton

A comparison of Table 9 to Tables 7 and 8 above shows that SCR at the Eunice Gas Plant Units 17A, 18B, 19A, 25A, and 26A is actually more cost effective than SoLoNOx at DCP's assumed 70-80% control or even assuming SoLoNOx can achieve 15 ppmv. SCR could be even more cost effective if there are opportunities to share an SCR between two or more combustion turbines. Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[139] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15%

[136] EPA's Control Cost Manual indicates that SCR at industrial units has a life of 25-years. *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.
[137] This was calculated from DCP Midstream's Total Annual Cost of SCR by subtracting the product of DCP's capital cost of SCR and a cost recovery factor reflective of DCP's assumed 5.5% interest rate and 20-year life.
[138] Estimated by multiplying DCP's annual operational costs of SCR by a factor of 1.177.
[139] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.

oxygen.[140] NMED should require DCP Midstream to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

III. IACX Roswell – Bitter Lake Compressor Station

The IACX Roswell, LLC Bitter Lake Compressor Station is located 13 miles northeast of Roswell, New Mexico and identified by NMED as contributing to regional haze at the Salt Creek WA Class I area.[141] NMED has described the facility processes as follows:

> The function of the facility is to compress and dehydrate field natural gas for transport in underground pipelines, to extract natural gas liquids, and to recover helium.[142]

According to the permit, the plant includes two Cooper-Bessemer 2-stroke lean-burn RICE, a glycol dehydrator with two associated reboilers, a refrigeration unit, and three tanks.[143] In IACX's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Cooper-Bessemer 2SLB RICE GMVH-10C: Units C-891 and C-893.[144]

The selection of these two engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[145] The following provides a review of the company's four-factor analyses.

A. Units C-891 and C-893: Cooper-Bessemer GMVH-10C 2-Stroke Lean Burn RICE

Units C-891 and C-893 are two-stroke lean-burn RICE that were constructed in the 1980s, each with a capacity of 2,250 hp.[146] The units each have an hourly NOx limit of 20 lb/hr and an annual NOx limit of 87.6 tpy.[147] That is the extent of information provided on the actual NOx emissions from these units. NMED should request more information on the units' current hours of operation and actual NOx emissions.

[140] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.
[141] November 2019 Regional Haze Four-Factor Analysis for IACX Roswell, LLC Bitter Lake Compressor Station at 3.
[142] Title V Operating Permit P047-R3 for Bitter Lake Compressor Station at A4.
[143] Title V Operating Permit P047-R3 for Bitter Lake Compressor Station at A6–A7.
[144] November 2019 Regional Haze Four-Factor Analysis for IACX Roswell, LLC Bitter Lake Compressor Station at 4.
[145] *Id.*
[146] Title V Operating Permit P047-R3 for Bitter Lake Compressor Station at A7.
[147] *Id.* at A8.

1. Use of Low Emission Combustion Technology

IACX claims that the Cooper-Bessemer GMVH-10C engines are currently operating with turbochargers and efficient combustion air intercoolers and describes these as "Clean Burn Technology (CBT)."[148] And IACX states that, "[b]ased on manufacturer guidance, the addition of these clean burn technologies allows the engines to range from 1.74 to 3.04 g/hp-hr, which allows for 25% to 57% reduction in NOx emissions; thus, no further assessment of these control practices is included in this report."[149] Yet, the permitted maximum hourly NOx emission rate of 20 lb/hr does not reflect the levels of NOx emissions claimed by IACX in its four-factor analysis. This hourly NOx emission rate is equivalent to 4 g/hp-hr for a 2,250 hp engine. A recent permit application supplied an uncontrolled NOx emission rate of 4 g/hp-hr, based on "engine manufacturer data."[150] This NOx emission level does not reflect the levels of NOx emissions achievable with LEC technology. In order to effectively evaluate a company's assessment of LEC a more precise definition of LEC technologies, and associated achievable emission rates, is needed.

NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).

For reference, the following additional sources of information regarding NOx emission rates specific to Cooper-Bessemer GMV model engines – both uncontrolled and with LEC technology – are provided here:

- EPA's 2000 RICE Update includes NOx emissions test data for specific engines, including Cooper-Bessemer GMV-10C, 2-stroke, lean-burn, 1,100 hp RICE retrofitted with LEC. Tested at 0.61 g/bhp-hr.[151]

- An evaluation by a technical group for the Pipeline Research Council International looked at three of the most representative make / models of 2-stroke lean-burn compressor engines: (1) 2,250 hp Cooper GMVH-10; (2) 2,000 hp Clark TLA-6; and (3) 2,500 hp Cooper GMW-10. According to a technical report by the OTC describing this evaluation, "[t]he evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring."[152]

[148] November 2019 Regional Haze Four-Factor Analysis for IACX Roswell, LLC Bitter Lake Compressor Station at 7.
[149] *Id.*
[150] Bitter Lake Compressor Station permit application P047R3 (8/17/2016) Section 6, Page 2.
[151] EPA 2000 RICE Update at 4-8.
[152] Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, p. 24, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf [hereinafter referred to as "2012 OTC Report"].

EPA describes LEC retrofit kits designed to achieve extremely lean air-to-fuel ratios – in order to minimize NOx emissions – as encompassing the following retrofit technologies:

- Redesign of cylinder head and pistons to improve mixing (on smaller engines)
- Precombustion chamber (on larger engines)
- Turbocharger
- High energy ignition system
- Aftercooler
- Air-to-fuel ration controller (AFRC)[153]

So, in addition to the turbochargers and upgraded intercooler systems already employed at these Cooper-Bessemer engines, NMED should request that the company evaluate the cost effectiveness of retrofitting these engines with additional LEC technologies – e.g., precombustion chambers, high energy ignition systems, AFRCs, etc. – to further reduce NOx emissions from these engines– e.g., to achieve emission levels as low as 0.5 g/hp-hr. Without data on actual NOx emissions from these engines it's not possible to know if, in fact, the current "clean burn technologies" employed at these units are achieving the emission levels of 1.74 to 3.04 g/hp-hr (that are based on manufacturer guidance) identified in the company's four-factor analysis. NMED should ask for test data reflective of actual operations at maximum operating capacity and ensure that these emission rates are a reasonable projection of NOx emissions in 2028.

2. Use of SCR

IACX did not evaluate SCR for Units C-891 and C-893, primarily because it claimed that the two engines run on ongoing variable loads and an SCR system may not function effectively at variable loads.[154] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly if it could achieve greater NOx emissions reductions from these units cost effectively.

[153] EPA, Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500-0508, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance, August 2016, Appendix A at 5-3, *available at:* https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0500-0508 [hereinafter referred to as "2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls"].
November 2019 Regional Haze Four-Factor Analysis for IACX Roswell, LLC Bitter Lake Compressor Station at 7.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[155]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[156] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[157] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

IV. Targa Eunice Gas Processing Plant

The Targa Midstream Services, LLC Eunice Gas Plant is a natural gas processing plant identified by NMED as potentially contributing to regional haze at the Carlsbad Caverns National Park Class I area.[158] NMED has described the facility processes as follows:

> The function of the facility is to receive field natural gas, perform dehydration and removal of carbon dioxide and hydrogen sulfide, and separate natural gas liquids (NGL). The products (natural gas and NGL) are compressed or pumped to sales pipelines for distribution.[159]

According to the permit, the plant includes 21 reciprocating internal combustion engines (RICE), two boilers, an amine still, three electric compressors, backup diesel generators, flares, glycol dehydrator sources, heaters, and storage tanks.[160] In Targa's four-factor submittal, the company evaluated air pollution controls for the following emission units:

- Clark 2SLB RICE BA-8: Units C-01, C-02, C-03, C-04, C-05, C-06, C-07, C-09

[155] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[156] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[157] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[158] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 1-1.
[159] Title V Operating Permit P109-R3 for Eunice Gas Processing Plant at A3.
[160] *Id.* at A7-A9.

- Clark 2SLB RICE HBA-8: Units C-10, C-11, C-12
- Clark 2SLB RICE HBA-T8: Unit C-13
- Wickes/Type A Boiler: Units B-01, B-02.[161]

The selection of these sources for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hr or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[162] The following provides a review of the company's four-factor analyses.

A. Units C-01 through C-07, C-09 through C-13: Clark Natural Gas-Fired 2-Stroke Lean-Burn RICE

Units C-01 through C-07 and C-09 are Clark BA-8 two-stroke lean-burn RICE that were constructed in 1984, each with a capacity of 1,200 hp.[163] Units C-01 through C-07 each have an hourly NOx limit of 53.6 lb/hr and an annual NOx limit of 234.8 tpy.[164] Unit C-09 is restricted to 500 hours per year operation and has an hourly NOx limit of 53.6 lb/hr and an annual NOx limit of 13.4 tpy.[165]

Units C-10 through C-12 are Clark HBA-8 two-stroke lean-burn RICE that were constructed in 1984, each with a capacity of 1,600 hp.[166] The units each have an hourly NOx limit of 77.2 lb/hr and an annual NOx limit of 19.3 tpy.[167] These units are restricted to 500 hr/yr operation.[168] Unit C-13 is a Clark HBA-T-8 two-stroke lean-burn RICE that was constructed in 1984, with a capacity of 2,050 hp.[169] This unit has an hourly NOx limit of 61.1 lb/hr and an annual NOx limit of 267.5 tpy.[170]

1. Evaluation of Baseline NOx Emissions

Targa's four-factor submittal includes unit-specific operating hours based on 2016 emission inventory calculations or based on permit limits of 500 hr/yr for some units (C-09 through C-12). Uncontrolled NOx emission rates (g/hp-hr) in Targa's original four-factor analysis are, for all but one unit, based on a single performance test conducted in July 2015. The NOx emission rate for the one unit without performance test data, Unit C-03, is noted as, "from client."[171] Targa's February 2020 Addendum includes a corrected uncontrolled NO_x emission rate for C-03,

[161] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 2-7.
[162] *Id.* at 1-3.
[163] Title V Operating Permit P109-R3 for Eunice Gas Processing Plant at A7.
[164] *Id.* at A10.
[165] *Id.* and NSR Permits 067-M8R1.
[166] Title V Operating Permit P109-R3 for Eunice Gas Processing Plant at A7.
[167] *Id.* at A10.
[168] *Id*. at A12 and NSR Permits 067-M8R1 and 067-M7.
[169] Title V Operating Permit P109-R3 for Eunice Gas Processing Plant at A7.
[170] *Id.* at A11.
[171] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant. *See, e.g.,* Appendix B Unit C-03.

based on a 2015 performance test, of 14.192 g/hp-hr.[172] The actual emission rates for these units, based on the July 2015 testing, and the allowable NOx emission rates are shown in the table below.[173]

Table 10. Targa Eunice Gas Processing Plant 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Actual Emissions from April 2015 Test Data [g/hp-hr]
C-01	1,200	53.6	20.3	13.165
C-02	1,200	53.6	20.3	9.226
C-03	1,200	53.6	20.3	14.192
C-04	1,200	53.6	20.3	11.742
C-05	1,200	53.6	20.3	9.285
C-06	1,200	53.6	20.3	13.261
C-07	1,200	53.6	20.3	13.787
C-09	1,200	53.6	20.3	17.249
C-10	1,600	77.2	21.9	11.401
C-11	1,600	77.2	21.9	16.265
C-12	1,600	77.2	21.9	9.838
C-13	2,050	61.1	13.5	13.654

As shown, the actual emission rates for most of these units—with the exception of unit C-13—are lower than these units' allowable NOx emission rates, with some less than 50% of allowable levels. So, either the 2015 performance test data was not conducted while the engines were operating at maximum capacity or the allowable NOx emission rates have been set unreasonably high. NMED should present information on the 2015 test data so the circumstances of the tests can be reviewed. Targa's February 2020 Addendum included the results from portable
analyzer testing conducted over a few days in August 2016 for the engines at the Saunders Gas Plant, which presumably are the tests used in determining baseline emissions for the four-factor analysis for that source.[174] NMED and Targa should review performance tests based on EPA Reference Methods for the Eunice Gas Plant to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. Citing variability in test data, Targa admits that these data are only a snapshot in time and only provide potential emissions based on that snapshot.[175] If testing is only done sporadically and is not done using EPA Reference Methods then it is questionable that such test data truly

[172] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 7.
[173] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant Appendix B.
[174] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 18-62.
[175] *Id.* at pdf page 6.

reflect an accurate projection of emissions expected over the lifetime of the controls being evaluated.

According to the source's Title V permit application, the allowable NOx emissions for these units are based on performance test data. Specifically, in the April 2018 Title V renewal application for the Eunice Gas Processing Plant, permitted rates for units C-01 through C-07 and C-09 of 53.6 lb/hr (equivalent to 20 g/hp-hr) are based on "stack data."[176] Note, stack test-based emissions are included for units C-09 through C-11, which are from the 2008 Title V renewal application, and are more in line with the emission rates used in the four-factor analysis (i.e., the Title V application lists "stack test-based emissions" for unit C-09 of 44.6 lb/hr (16.9 g/hp-hr) and for units C-10 and C-11 of 60 lb/hr (17.0 g/hp-hr), compared to the emission rates in the four-factor analysis of 17.249, 11.401, and 16.265 g/hp-hr for units C-09, C-10, and C-11, respectively).[177] However, the "current permitted rates (based on stack data)" for Units C-01 through C-07 that are listed in Targa's 2018 Title V permit application are equivalent to 20 g/hp-hr and are significantly higher than the NOx emission rates that the company's four-factor cost effectiveness analysis is based upon, meaning NOx reductions estimates for the various control options considered may be underestimated. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on a more comprehensive estimate of emissions expected in 2028.

2. Use of Low Emission Combustion Technology

Targa describes the LEC control technologies for these 2SLB engines as "Clean Burn Technology (CBT)."[178] Targa determined that this LEC technology is a technically feasible option for the 2SLB RICE units at the Eunice Gas Plant and the cost analysis provided in its four-factor analysis indicates this control is cost effective, especially for the engines that operate without restriction (i.e., Units C-01 through C-07 and C-13). Despite this, Targa concludes these retrofits would be uneconomical.[179]

The cost analysis in Targa's four-factor submittal doesn't support this claim, and the cost effectiveness of controls may be even more favorable than what is presented by Targa.

In its original November 2019 submittal, Targa presents cost effectiveness of controls for units C-01 through C-07 and for unit C-13 that range from $900–$6,000 per ton. The capital cost estimates are based on "manufacturer specification" and the annual operating and maintenance costs were provided by Targa.[180] Note, these annual operating and maintenance costs are higher than what was provided by other companies for LEC retrofits for similar

[176] *See* April 2018 Title V Permit Application for Eunice Gas Processing Plant at pdf page 50.
[177] *Id.* at 47 and 48.
[178] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 2-9.
[179] *Id.* at 7-1.
[180] *Id.* Appendix B. Note, Targa stated, on pdf page 8 of its February 2020 Addendum, that "the O&M cost included in the analyses were based on Targa's experience operating similar control devices at other sites for expected maintenance and repair."

engines.[181] Targa's February 2020 Addendum included a revised control cost analysis, with costs effectiveness ranging from $3,331–$121,892 per ton, based on much higher cost estimates, and based on higher controlled NOx emission rates.[182] The capital investment for the Clean Burn Technology in the original submittal totaled just under $1 million per engine, compared to over $5 million in the Addendum.[183] The original capital cost estimates are in line with other capital cost estimates for LEC controls at other similar engines, at less than $140/hp,[184] whereas the capital cost estimates in Targa's Addendum are significantly higher, at up to $400/hp. It appears that the revised costs include $3 million—per engine—for electrical power, which Targa indicated in its original submittal could cost between $1–$3 million but would require an engineering assessment in order to know the full cost of this upgrade.[185] Note, even without these electrical upgrades, the other capital costs reach over $200/hp which is still significantly higher than the Targa's original estimates of less than $140/hp.

In its original submittal Targa stated that the Clean Burn Technology upgrades would either include turbochargers or externally driven blowers, with the electrical upgrades only necessary if blowers are used.[186] Even assuming the need for blowers and the highest cost estimate for upgrading the electrical substation (i.e., $3 million instead of $1 million), the cost effectiveness of these LEC controls is as low as $3,300—$5,600/ton for frequently-operating engines.[187] Assuming the electrical upgrades would cost $1 million instead of $3 million or that electrical upgrades aren't needed would obviously result in much more favorable cost effectiveness of these controls.

Note that Targa's submittal for the Saunders Gas Plant includes an analysis of the exact same LEC controls for the 2SLB RICE at that facility—e.g., requiring turbochargers or externally driven blowers—and the capital costs for that analysis are in line with the original cost estimates for the Eunice Gas Plant, at <$140/hp. And Targa's February 2020 Addendum for the Eunice, Monument, and Saunders gas plants did not include higher cost estimates for increased electricity needs at the Saunders Gas Plant. It's true that there are on-site electrical generation capabilities at the Saunders Gas Plant (e.g., units G-01 through G-04) but Targa's analysis for this facility does not appear to reflect a measurable increase in capital cost expenditures

[181] *See, e.g.,* November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant, which assumed O&M costs of $40,000/yr for Clark HRA-8 engines.
[182] *See* February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 7 and 83—95.
[183] Note, these original capital cost estimates are in line with other company analyses for similar engines, e.g., Harvest Four Corners Kutz Canyon Gas Processing Plant's analysis for Clark HBA-8 engines used capital cost estimates of $1,000,000. Also, EPA's 2000 RICE Update (p. 5-2) included capital cost estimates for third-party retrofit of a Clark Model HSRA, 2SLB 1,000 hp 8-cylindar engine at a pipeline station of $710,000.
[184] *See, e.g.*, November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant cost data for Clark engines at just under $140/hp.
[185] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 2-10 and 3-2.
[186] *Id.*
[187] E.g., cost effectiveness of C-13 at 7,560 hr/yr is $3,331/ton, C-06 at 8,123 hr/yr is $5,465/ton, C-03 at 7,275 hr/yr is $5,430/ton, C-01 at 8,009 hr/yr is $5,600/ton.

associated with the externally driven blowers that may be required at this site for LEC controls at the 2SLB RICE. And at any rate, any cost analysis associated with upgrades to a power substation that serves the Eunice Gas Plant should be considered separately, as part of a facility-wide assessment of the cost effectiveness of electrifying additional sources that could further reduce NOx emissions from the plant (e.g., electrification of additional engines).

In Targa's original submittal, its cost effectiveness analysis assumes controlled NOx emission rates of 2 g/hp-hr based on "information provided by the engine control vendor."[188] The corresponding NOx emissions reductions in Targa's original four-factor analysis for these units range from 61% to 88%.[189] Note, greater emissions reductions would result from control of units that are operating at levels closer to permitted levels (which are, again, based on test data for the units according to the source's Title V permit application) would mean that the LEC controls would be even more cost effective than what is shown in the original four-factor analysis. Targa specifically describes the control technology for these engines as able to reduce NOx emissions between 70% and 90%.[190] Subsequently, Targa's Addendum includes a new analysis of the cost effectiveness of reducing NOx emissions to levels of 4 g/hp-hr and 5 g/hp-hr, reflecting NOx emissions reductions of only 46–77%.[191]

In addition, as a result of assuming what could be unreasonably low NOx emission rates for current uncontrolled emissions from some of the 2SLB engines, i.e., emission rates based on performance test data that show much lower rates than the permitted limits for these units (that, according to Targa's Title V permit application, are based on stack data),[192] Targa then also potentially further underestimates the magnitude of potential NOx reductions for these units in its cost effectiveness analysis. The permitted hourly NOx emission rates, based on stack test data, are as follows: 20 g/hp-hr (units C-01 through C-07 and C-09); 23 g/hp-hr (units C-10 through C-12); and 14 g/hp-hr (unit C-13).[193] The permitted rate for unit C-13 is in line with the performance test data from 2015 used in the four-factor analysis but the other units' emission rates are significantly lower in the four-factor analysis than the stack test based rates in the source's Title V permit application. Therefore, the potential emissions reductions achieved by retrofitting units C-01 through C-07 and C-09 through C-12 could be much greater than what the four-factor analysis shows for these units. For uncontrolled permitted emission rates around 20 g/hp-hr, controlled rates of 2 g/hp-hr would achieve 90% reduction in NOx emissions.

[188] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 3-3.
[189] *Id.* at Appendix B.
[190] *Id.*at 2-9.
[191] *See* February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 83—95.
[192] *See* April 2018 Title V Permit Application for Eunice Gas Processing Plant at pdf page 50.
[193] *Id.* at pdf pages 48-51.

With respect to the life assumed for LEC control, Targa assumed a 20-year period.[194] Targa appears to base this on EPA's guidance default for SCR.[195] It's possible that LEC controls can last 25 years, as stated in other cost effectiveness analyses submitted to NMED for LEC controls.[196]
Also, Targa uses an interest rate of 5.5% which is likely high and therefore underestimates annualized costs of control for these engines. As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

Revising Targa's cost effectiveness analyses to address some of these issues, including assuming: 1) a 4.7% interest rate (instead of 5.5%), 2) a 25-year life of LEC (instead of an assumed 20-year life), and 3) emissions reductions of 90% based on potential operation at permitted levels (based on stack test data), improves the cost effectiveness of these controls even further, as shown in the table below. Note, this revised analysis uses Targa's original capital investment costs, since these are more in line with the cost analysis for its Saunders Gas Plant and with other capital cost estimates for LEC technology for similar engines; additional capital investments related to electrical capacity upgrades at the facility should be assessed, in more detail, as a separate broader analysis. Further note, this revised analysis assumes a slightly lower NOx emissions reductions estimate for unit C-13 of 85%, based on this unit's actual emission rate, since this emission rate is in line with permitted emissions for this unit.

[194] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant Appendix B.
[195] *Id.*
[196] *See* 2019 Four-Factor Analyses for Roswell Compressor No. 9 and Jal No. 3.

Table 11. Cost Effectiveness of LEC at Uncontrolled Eunice Gas Plant Units C-01 through C-07 and C-09 through C-13 to Reduce NO_x Levels to 2 g/hp-hr, Assuming 90% Reductions in NOx Emissions, at 4.7% Interest Rate, and a 25-Year Life of Controls, 2019 $

Unit	Size [hp]	Capital Cost of LEC to Reduce NOx from the Uncontrolled rate of 20 g/hp-hr	Annual O&M Costs	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (90% NOx Reduction)	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC, $/ton
C-01	1,200	$950,000	$100,000	$165,392	8,009	191	$867/ton
C-02	1,200	$950,000	$100,000	$165,392	4,271	102	$1,626/ton
C-03	1,200	$950,000	$100,000	$165,392	7,275	173	$955/ton
C-04	1,200	$950,000	$100,000	$165,392	5,996	143	$1,159/ton
C-05	1,200	$950,000	$100,000	$165,392	7,684	183	$904/ton
C-06	1,200	$950,000	$100,000	$165,392	8,123	193	$855/ton
C-07	1,200	$950,000	$100,000	$165,392	6,476	154	$1,073/ton
C-09	1,200	$950,000	$100,000	$165,392	500*	12	$13,893/ton
C-10	1,600	$950,000	$100,000	$165,392	500*	16	$10,420/ton
C-11	1,600	$950,000	$100,000	$165,392	500*	16	$10,420/ton
C-12	1,600	$950,000	$100,000	$165,392	500*	16	$10,420/ton
C-13	2,050	$950,000	$100,000	$165,392	7,560	203**	$814/ton

* These units are limited to 500 hr/yr operation in NSR Permits 067-M8R1 and 067-M7.

** Emissions reductions for Unit C-13 are based on controlling NOx emissions from the unit's actual emission rate of 14 g/hp-hr to 2 g/hp-hr (i.e., assuming NOx emissions reductions of 85%, instead of the 90% reduction assumed for all other units).

In Targa's original submittal it specifically describes the LEC modifications for these engines as including pre-combustion chambers and fuel systems to significantly lean the combustion mixture.[197] And Targa notes that the modifications will, "need turbochargers or externally driven blowers added as well."[198] Regarding the possibility of externally driven blowers, Targa points out the following:

> If a 2SLB engine does need an externally driven blower, this will be an electric blower and require electricity to operate. At this time, Eunice Gas Plant would have to significantly upgrade the power substation at the plant to operate blowers associated with these controls. The cost provided in Section 3 of this report does not include the cost to upgrade the electrical substation at the facility. An engineering design assessment would need to be completed before a total cost for the upgrade can be provided but is estimated at $1 million to $3 million.

[197] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 2-9.
[198] *Id.* at 2-10.

> Even with the power concerns, Targa has determined that this method of NOX control is feasible for the 2SLB engines at the facility.[199]

In Targa's Addendum, it more specifically describes the technologies included in its updated analysis, including adding a pre-combustion chamber with power cylinder heads, modifications to the fuel system, adding a turbocharger system, and various upgrades to the intercooler system.[200]

As Targa acknowledges, it's not clear to what degree – and at what cost – additional upgrades to the power substation would be required. And Targa has stated that these LEC controls are feasible regardless of power concerns. So any claim that electrical power upgrades would render this control infeasible must be more carefully evaluated based on more specific data (e.g., energy needs in kW and the costs of those energy needs) in order to be able to assess the cost effectiveness of the additional electricity usage that would be required to power any blowers, or any other potential electrified sources, as determined from a full engineering assessment.

3. Use of SCR.

Targa did not evaluate SCR for these units, primarily because it claimed that, "most 2SLB engines have a poor air-to-fuel ratio that will not support the SCR control."[201] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly because Targa does not consider LEC to be economical.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[202]

[199] *Id.*
[200] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 7.
[201] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 2-11.
[202] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[203] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[204] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

B. Natural Gas-Fired Boilers (Units B-01 and B-02)

Targa also evaluated controls for the Units B-01 and B-02 natural gas-fired boilers. These boilers are Wickes Type A boilers, each with a permitted capacity of 100 MMBtu/hr that were manufactured in 1972.[205] The units each are subject to allowable NOx emission limits of 20.6 lb/hr and 90.0 tpy.[206]

Targa states that the two boilers already are using good combustion practices and have low NOx burners. Targa states that ultra-low NOx burners are available but would be technically infeasible at times for the Eunice Gas Processing Plant boilers because of the age of the boilers and the vendors' concerns with the higher Btu content of the fuel.[207] Targa also found SCR to be technically infeasible for the boiler claiming the significant power requirements would require the power at the plant to be significantly upgraded and redesigned. In addition, Targa found the selective non-catalytic reduction (SNCR) was not technically feasible due to concerns about how low loads will impact the temperature profile and optimal operating temperature of the control. Targa's dismissal of all three of these controls as technically infeasible only provides brief claims of technical infeasibility with no details specific to the Unit B-01 and B-02 boilers design or operation that make the particular control technically infeasible for the units. Further, issues of cost do not make a control technically infeasible. Instead, the costs of any requirements to alter a boiler to be able to operate with ultra-low NOx burners or to upgrade electricity to power SCR needs to be costed out and considered in the cost effectiveness analysis. NMED must require more information from Targa to exclude these controls as technically infeasible, particularly ultra-low NOx burners and SCR, especially given that Targa's

[203] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[204] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[205] 11/29/2019 Title V Operating Permit For Targa Eunice Gas Processing Plant at A7.
[206] *Id.* at A11.
[207] November 2019 Four-Factor Analysis for Targa Eunice Gas Processing Plant at 2-13.

research of RACT/BACT/LAER Clearinghouse entries shows that these controls are commonly required for natural gas-fired industrial boilers.[208]

The only NOx control evaluated by Targa for the boilers is flue gas recirculation (FGR). Targa assumed that FGR would reduce NOx to 45 ppm, which would be 50% control from the base NOx emissions rate of 90 ppm.[209] At least one boiler manufacturer, Cleaver Brooks, states that FGR is one of the more commonly used methods to reduce NOx emissions and that it can achieve up to 80% NOx reduction.[210] However, the cost effectiveness of the control was calculated by Targa to be between $16,000 to $19,000/ton.[211] Part of the reason for the high cost effectiveness is that Targa assumed only a 20 year life of controls and a 5.5% interest rate. FGR consists of recycling a portion of the flue gas from the stack to the burner windbox. The NOx reduction occurs due to the recirculated flue gas reducing combustion temperatures and because of lowering the oxygen content in the flame zone.[212] The life of FGR should be the same as the life of the boiler. Targa did not identify the remaining useful life of boilers B-01 and B-02, but the boilers have been in operation since 1972 or 47 years. The lifetime of a boiler is typically thought to be at least 30 years, and Targa did not give any indication of any end of life for the boilers. Thus, Targa should have assumed a 30-year life of FGR. Also, as previously discussed, a lower interest rate should have been used, no higher than 4.7%.

However, the other reason the cost effectiveness of FGR appears to be so high at Units B-01 and B-02 is because the 2016 annual baseline emissions relied on by Targa are very low compared to the units' allowable emissions (8.08 and 6.73 tpy compared to 90 tpy allowable emissions each for Units B-01 and B-02). Yet, a review of the 2016 hourly emissions of NOx compared to the annual emissions of NOx indicates that the boilers operate very close to 8,760 hours per year. If the boilers' NOx emissions are expected to continue to be as low as indicated by the 2016 emission inventory, it seems questionable that the emission limits applicable to these units are reflective of the existing good combustion practices and low NOx burners. NMED should reduce the emission limits to reflect the current NOx controls on the boilers. If the boiler NOx emissions in 2016 are anomalous and not reflective of future operations of the boilers in 2028, then NMED should require a revised cost effectiveness analysis based on a more realistic estimate of annual NOx emissions.

[208] *Id.* at Appendix A.
[209] *Id.* at 3-3 and at Appendix B (pdf pages 35 and 36 of document).
[210] *See* Cleaver Brooks, Strategies to Reduce NOx Emissions, Tip Sheet: October 2014, available at http://cleaverbrooks.com/september/. *See also* W.C. Rouse & Son, Low NOx Without Flue Gas Recirculation, in which it is stated that for gas-fired boilers, FGR can achieve 75-80% NOx reduction, available at https://www.wcrouse.com/low-nox-without-flue-gas-recirculation/.
[211] *Id.* at Appendix B (pdf pages 35 and 36 of document).
[212] EPA, AP-42 Emission Factor Document, Natural Gas Combustion, at page 3.

V. Targa Monument Gas Plant

The Targa Midstream Services, LLC Monument Gas Plant is a natural gas processing plant identified by NMED as potentially contributing to regional haze at the Carlsbad Caverns National Park Class I area.[213] NMED has described the facility processes as follows:

> The function of the facility is to process natural gas through inlet separation, an amine system for acid gas removal (carbon dioxide and hydrogen sulfide), dehydration for water removal, and the separation of methane from natural gas liquids (NGL). The natural gas is delivered to sales pipelines, propane is transported offsite with pressurized tank trunks, and the separated condensate is loaded into tank trucks for transport offsite.[214]

According to the permit, the plant includes seven RICE units, a steam boiler, heaters, gas turbines, storage tanks, vapor recovery units, an amine unit, and flares.[215]

In Targa's four-factor submittal, the company evaluated air pollution controls for the following emission units:

- Clark 2SLB RICE RA-8 (800 hp): Units C-01, C-02
- Clark 2SLB RICE RA-6 (600 hp): Units C-04, C-05, C-06
- Clark 2SLB RICE HRA-8 (880 hp): Unit C-24
- Cooper-Bessemer GMVA-8 (1,100 hp): Unit C-28
- Amine Gas Treating Unit / Flare: Unit AM-01 / F-03.[216]

The selection of these sources for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hr or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[217] The following provides a review of the company's four-factor analyses for the engines listed above. The Amine Gas Treating Unit/Flare is addressed in Section XXIII further below.

[213] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Monument Gas Plant at 1-1.
[214] Title V Operating Permit P110-R2M1 for Monument Gas Plant at A3.
[215] *Id.* at A5–A7.
[216] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 2-1.
[217] *Id.* at 1-3.

A. Units C-01, C-02, C-04 through C-06, C-24, and C-28: Natural Gas-Fired 2-Stroke Lean-Burn RICE

Units C-01 and C-02 are Clark RA-8 two-stroke lean-burn compressor engines that were constructed in 1956, each with a capacity of 800 hp.[218] These units each have an hourly NOx limit of 27.8 lb/hr and an annual NOx limit of 121.8 tpy.[219]

Units C-04 through C-06 are Clark RA-6 two-stroke lean-burn compressor engines that were also constructed in 1956, each with a capacity of 600 hp.[220] The three units each have an hourly NOx limit of 25.1 lb/hr and an annual NOx limit of 109.9 tpy.[221]

Unit C-24 is a Clark HRA-8 two-stroke lean-burn compressor engine that was constructed in 1969, with a capacity of 880 hp.[222] This unit has an hourly NOx limit of 41.9 lb/hr and an annual NOx limit of 183.5 tpy.[223]
Unit C-28 is a Cooper-Bessemer GMVA-8 two-stroke lean-burn compressor engine that was constructed in 1977, with a capacity of 1,100 hp.[224] This unit has an hourly NOx limit of 16.6 lb/hr and an annual NOx limit of 72.7 tpy.[225]

1. Evaluation of Baseline NOx Emissions

Targa's four-factor submittal includes unit-specific operating hours based on 2016 emission inventory calculations. Uncontrolled NOx emission rates (g/hp-hr) in Targa's original four-factor analysis are based on a single performance test conducted for each engine in April 2015. The actual emission rates for these units, based on this April 2015 testing, and the allowable NOx emission rates are shown in the table below.[226]

Table 12. Targa Monument Gas Plant 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Actual Emissions from April 2015 Test Data [g/hp-hr]
C-01	800	27.8	15.8	11.9
C-02	800	27.8	15.8	9.8
C-04	600	25.1	19.0	9.9
C-05	600	25.1	19.0	8.4
C-06	600	25.1	19.0	11.4

[218] Title V Operating Permit P110-R2M1 for Monument Gas Plant at A6.
[219] *Id.* at A8.
[220] *Id.* at A6.
[221] *Id.* at A8.
[222] *Id.* at A6.
[223] *Id.* at A8.
[224] *Id.* at A6.
[225] *Id.* at A8.
[226] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant Appendix B.

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Actual Emissions from April 2015 Test Data [g/hp-hr]
C-24	880	41.9	21.6	18.2
C-28	1,100	16.6	6.8	6.3

As shown, the actual emission rates for all units, with the exception of C-28, are much lower than the units' allowable hourly NOx emission rates so, either the 2015 test data for these units was not conducted while the engines were operating at maximum capacity or the allowable NOx emission rates for these units have been set unreasonably high. NMED should present information on the 2015 test data so the circumstances of the tests can be reviewed. Targa's February 2020 Addendum included the results from portable analyzer testing conducted over a few days in August 2016 for the engines at the Saunders Gas Plant, which presumably are the tests used in determining baseline emissions for the four-factor analysis for that source.[227] NMED and Targa should review performance tests at the Monument Gas Plant, that are based on EPA Reference Methods, to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. Citing variability in test data, Targa admits that these data are only a snapshot in time and only provide potential emissions based on that snapshot.[228] If testing is only done sporadically and is not done using EPA Reference Methods then it is questionable that such test data truly reflect an accurate projection of emissions expected over the lifetime of the controls being evaluated.

According to the August 2018 Title V renewal application for the Monument Gas Plant, NOx emissions were determined, "based on stack test data with a safety factor..."[229] The permitted rates for these units (with the exception of unit C-28)—that are based on stack test data—are significantly higher than the NOx emission rates that the company's four-factor cost effectiveness analysis is based upon, meaning NOx reductions estimates for the various control options considered may be underestimated. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on a more comprehensive estimate of emissions expected in 2028.

2. Use of Low Emission Combustion Technology

Targa describes the LEC control technologies for these 2SLB engines as "Clean Burn Technology (CBT)."[230] According to EPA, "[t]he term "clean-burn" technology is a registered trademark of Cooper Energy Systems and refers to engines designed to reduce NOx by operating at high air-to-fuel ratios."[231] In Targa's original submittal it specifically describes the LEC modifications for

[227] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 18-62.
[228] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 6.
[229] *See* August 2018 Title V Permit Application for Monument Gas Plant at pdf page 36.
[230] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 2-3.
[231] EPA AP-42 Chapter 3, Section 3.2 (July 2000) at 3.2-2.

these engines as including pre-combustion chambers and fuel systems to significantly lean the combustion mixture.[232] And Targa notes that the modifications will, "need turbochargers or externally driven blowers added as well."[233] In Targa's February 2020 Addendum, it more specifically describes the technologies included in its updated analysis, including adding a pre-combustion chamber with power cylinder heads, modifications to the fuel system, adding a turbocharger system, and various upgrades to the intercooler system.[234]

Targa determined that this LEC technology is a technically feasible option for the 2SLB RICE units at the Monument Gas Plant and the cost analysis provided in its four-factor analysis indicates this control could be cost effective for some of these units (e.g., Unit C-24). Despite this, Targa concludes the following:

> However, retrofitting with these technologies would require Targa to spend significant amounts of time (for design and installation) and capital. In addition, based on the predominant wind direction and that SO_2, not NOx, is the contaminant of interest for visibility impairment in Carlsbad Caverns, NOx emissions from these pieces of equipment are inconsequential for regional haze purposes. Thus, retrofitting the Monument Gas Plant engines would be uneconomical and unnecessary for improving visibility.[235]

In terms of being uneconomical, the cost analysis in Targa's four-factor submittal doesn't necessarily support this claim for all engines, and more importantly, the cost effectiveness of controls may be even more favorable than what is presented by Targa.

In its original November 2019 submittal, Targa presents cost effectiveness of controls for these units that range from $1,688–$33,892 per ton. The capital cost estimates are based on "manufacturer specification" and the annual operating and maintenance costs were provided by Targa.[236] Note, these annual operating and maintenance costs are higher than what was provided by other companies for LEC retrofits for similar engines.[237] Targa's February 2020 Addendum included a revised control cost analysis, with costs effectiveness ranging from $6,398–$155,568 per ton, based on much higher cost estimates, and based on higher controlled NOx emission rates.[238] The capital investment for the Clean Burn Technology in the original submittal totaled $900,000 per engine, compared to over $5 million in the

[232] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 2-4.
[233] *Id*.
[234] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 7.
[235] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 7-1.
[236] *Id.* Appendix B. Note, Targa stated, on pdf page 8 of its February 2020 Addendum, that "the O&M cost included in the analyses were based on Targa's experience operating similar control devices at other sites for expected maintenance and repair."
[237] *See, e.g.,* November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant, which assumed O&M costs of $40,000/yr for Clark HRA-8 engines.
[238] *See* February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 7 and 96–102.

Addendum.[239] The original capital cost estimates are high, at $150—$270/hp, compared to other capital cost estimates for LEC controls at other similar engines.[240] The capital cost estimates in Targa's Addendum are significantly higher, at over $750/hp for some units (e.g., C-04 through C-06). It appears that the revised costs include $3 million for electrical power, which Targa indicated in its original submittal could cost between $1–$3 million but would require an engineering assessment in order to know the full cost of this upgrade.[241] Note, even without these electrical upgrades, the other capital costs come in at over $400/hp for some units, which is still significantly higher than the $/hp figures in Targa's original submittal.

In its original submittal, Targa stated that the Clean Burn Technology upgrades would either include turbochargers or externally driven blowers, with the electrical upgrades only necessary if blowers are used.[242] Even assuming the need for blowers and the highest cost estimate for upgrading the electrical substation (i.e., $3 million instead of $1 million), the cost effectiveness of these LEC controls is as low as $6,398/ton for unit C-24.[243] Assuming the electrical upgrades would cost $1 million instead of $3 million, or that electrical upgrades aren't needed would obviously result in much more favorable cost effectiveness of these controls.

Note that, Targa's submittal for the Saunders Gas Plant includes an analysis of the exact same LEC controls for the 2SLB RICE at that facility—e.g., requiring turbochargers or externally driven blowers—and the capital costs for that analysis are, generally, less than $140/hp. And Targa's February 2020 Addendum for the Eunice, Monument, and Saunders gas plants did not include higher cost estimates for increased electricity needs at the Saunders Gas Plant. It's true that there are on-site electrical generation capabilities at the Saunders Gas Plant (e.g., units G-01 through G-04) but Targa's analysis for this facility does not appear to reflect a measurable increase in capital cost expenditures associated with the externally driven blowers that may be required at this site for LEC controls at the 2SLB RICE. And at any rate, any cost analysis associated with upgrades to a power substation that serves the Monument Gas Plant should be considered separately, as part of a facility-wide assessment of the cost effectiveness of electrifying additional sources that could further reduce NOx emissions from the plant (e.g., electrification of engines).

[239] Note, these original capital cost estimates are in line with other company analyses for similar engines, e.g., Harvest Four Corners Kutz Canyon Gas Processing Plant's analysis for Clark HBA-8 engines used capital cost estimates of $1,000,000. Also, EPA's 2000 RICE Update (p. 5-2) included capital cost estimates for third-party retrofit of a Clark Model HSRA, 2SLB 1,000 hp 8-cylindar engine at a pipeline station of $710,000.

[240] *See, e.g.,* Four-Factor analyses for Chaco Gas Plant (Clark 2SLB RICE at $140/hp), Saunders Gas Plant (Cooper-Bessemer 2SLB RICE at $90-$138/hp), Roswell Compressor Station No. 9 (Cooper-Bessemer 4SLB RICE at $90/hp), Jal No. 3 (Cooper-Bessemer 2SLB RICE at $123/hp).

[241] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Monument Gas Plant at 2-4 and 3-2.

[242] *Id.*

[243] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 101.

The annual hours of operation for these engines varies significantly. According to Targa's submittal, the annual hours of operation used in the four-factor analysis are based on 2016 emission inventory data, as shown in the table below:

Table 13. Targa Monument Gas Plant 2SLB RICE Units Annual Operation

Unit	Size [hp]	Hours of Operation From 2016 EI Calculations [hr/yr]
C-01	800	2,357
C-02	800	4,069
C-04	600	990
C-05	600	2,035
C-06	600	3,938
C-24	880	6,610
C-28	1,100	573
AVERAGE		2,939

In Targa's Addendum, it indicated that annual hours of operation depend on various factors—e.g., including whether units are working, when they require maintenance, etc. —and will vary each year from engine to engine but, overall, are generally uniform.[244] According to Targa, "each year the engines will operate with different hours of operation and fuel usage."[245] NMED should request operation data for additional years for these units in order to be able to better assess the cost effectiveness of controls for operating schedules that reflect the full range of usage for these engines.

In Targa's original submittal, its cost effectiveness analysis assumes controlled NOx emission rates of 2 g/hp-hr based on "information provided by the engine control vendor."[246] The corresponding NOx emissions reductions in Targa's original four-factor analysis for these units range from 68.3% to 89%.[247] Note, greater emissions reductions would result from control of units that are operating at levels closer to permitted levels (which are, again, based on test data for the units according to the source's Title V permit application) would mean that the LEC controls would be even more cost effective than what is shown in the original four-factor analysis. Targa specifically describes the control technology for these engines as able to reduce NOx emissions between 70% and 90%.[248] Subsequently, Targa's Addendum includes a new analysis of the cost effectiveness of reducing NOx emissions to levels of 4 g/hp-hr and 5 g/hp-hr, reflecting NOx emissions reductions of only 37–78%.[249]

[244] *Id.* at 6.
[245] *Id.* at 6.
[246] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 3-2.
[247] *Id.* at Appendix B.
[248] *Id.*at 2-4.
[249] *See* February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 96—102.

In addition, as a result of assuming what could be unreasonably low NOx emission rates for current uncontrolled emissions from some of the 2SLB engines, i.e., emission rates based on performance test data that show much lower rates than the permitted limits for these units (that, according to Targa's Title V permit application, are based on stack data), Targa then also potentially further underestimates the magnitude of potential NOx reductions for these units in its cost effectiveness analysis. The permitted hourly NOx emission rates, based on stack test data, are notably higher than the actual emission rates used in the four-factor analysis for all but unit C-28, as shown in the table in the previous section.[250] Therefore, the potential emissions reductions achieved by retrofitting these units could be much greater than what the four-factor analysis shows due to potential underestimated baseline emissions, hours of operation, and emissions reductions. For uncontrolled permitted emission rates ranging from 15.8—21.6 g/hp-hr, controlled rates of 2 g/hp-hr would achieve 87—91% reduction in NOx emissions.

With respect to the life assumed for LEC control, Targa assumed a 20-year period.[251] Targa appears to base this on EPA's guidance default for SCR.[252] It's possible that LEC controls can last 25 years, as stated in other cost effectiveness analyses submitted to NMED for LEC controls.[253]
Also, Targa uses an interest rate of 5.5% which is likely high and therefore underestimates annualized costs of control for these engines. As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

Revising Targa's cost effectiveness analyses to address some of these issues, including assuming 1) a 4.7% interest rate (instead of 5.5%), 2) a 25-year life of LEC (instead of an assumed 20-year life), and 3) emissions reductions of 87—91% based on potential operation at permitted levels (based on stack test data), improves cost effectiveness of these controls even further, as shown in the table below. Note, this revised analysis uses Targa's original capital investment costs, since these are more in line with the cost analysis for its Saunders Gas Plant and with other capital cost estimates for LEC technology for similar engines; additional capital investments related to electrical capacity upgrades at the facility should be assessed, in more detail, as a separate broader analysis. Further note, this revised analysis assumes a NOx emissions reduction estimate for unit C-28 of just over 70%, based on this unit's actual emission rate, since this emission rate is in line with permitted emissions for this unit.

[250] *Also see* August 2018 Title V Permit Application for Monument Gas Plant at pdf pages 44–47.
[251] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant Appendix B.
[252] *Id.*
[253] See 2019 Four-Factor submittals for Roswell Compressor Station and Jal No. 3 which both assume 25-year life of controls for LEC.

Table 14. Cost Effectiveness of LEC at Uncontrolled Monument Gas Plant Units C-01, C-02, C-04 through C-06, C-24, and C-28 to Reduce NO_x Levels to 2 g/hp-hr, Assuming 87—91% Reductions in NOx Emissions, a 4.7% Interest Rate, and a 25-Year Life of Controls

Unit	Size [hp]	Capital Cost of LEC to Reduce NOx from an Uncontrolled Rate [2019$]	Annual O&M Costs [2019$]	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (87—91% NOx Reduction) [2019$]	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC [2019$], $/ton
C-01	800	$900,000	$100,000	$161,951	2,357	29	$5,661/ton
C-02	800	$900,000	$100,000	$161,951	4,069	49	$3,279/ton
C-04	600	$900,000	$100,000	$161,951	990	11	$14,570/ton
C-05	600	$900,000	$100,000	$161,951	2,035	23	$7,088/ton
C-06	600	$900,000	$100,000	$161,951	3,938	44	$3,663/ton
C-24	880	$900,000	$100,000	$161,951	6,610	126	$1,289/ton
C-28	1,100	$850,000	$100,000	$158,509	573	3	$47,086/ton*

* Emissions reductions for Unit C-28 are based on controlling NOx emissions from the unit's actual emission rate of 6.8 g/hp-hr to 2 g/hp-hr (i.e., assuming NOx emissions reductions of just over 70%), since this uncontrolled emission rate is in line with permitted emissions for this unit.
Capital costs for C-28 are listed as $850,000 based on manufacturer specification.

The cost effectiveness of LEC control could be significantly lower than what is shown above for engines that operate more frequently than in 2016. Targa stated, in its February 2020 Addendum, that "[w]ith regards to the engine usage, Targa attempts to use its engines uniformly but this does not mean equally on a calendar year basis."[254] An analysis that assumes each engine operates at the average annual operation of all engines in 2016, which is roughly 3,000 hours per year, e.g., would lower the cost effectiveness of Unit C-01 to $5,080/ton, units C-04 and C-05 to $5,491/ton each, and unit C-28 to $10,226/ton.

Regarding the possibility of externally driven blowers that would require electrical upgrades, Targa points out the following:

> If a 2SLB engine does need an externally driven blower, this will be an electric blower and require electricity to operate. At this time, Eunice Gas Plant would have to significantly upgrade the power substation at the plant to operate blowers associated with these controls. The cost provided in Section 3 of this report does not include the cost to upgrade the electrical substation at the facility. An engineering design assessment would need to be completed before a total cost for the upgrade can be provided but is estimated at $1 million to $3 million.

[254] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 6.

> Even with the power concerns, Targa has determined that this method of NOX control is feasible for the 2SLB engines at the facility.[255]

As Targa acknowledges, it's not clear to what degree – and at what cost – additional upgrades to the power substation would be required. And Targa has stated that these LEC controls are feasible regardless of power concerns. So any claim that electrical power upgrades would render this control infeasible must be more carefully evaluated based on more-specific data (e.g., energy needs in kW and the costs of those energy needs) in order to be able to assess the cost effectiveness of the additional electricity usage that would be required to power any blowers, or any other potential electrified sources, as determined from a full engineering assessment.

3. Use of SCR.

Targa did not evaluate SCR for these units, primarily because it claimed that, "most 2SLB engines have a poor air-to-fuel ratio that will not support the SCR control."[256] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly because Targa does not consider LEC to be economical.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[257]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[258] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost

[255] *Id.*
[256] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 2-5.
[257] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[258] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.

Manual[259] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

VI. Targa Saunders Gas Plant

The Targa Midstream Services, LLC Saunders Gas Plant is a natural gas processing plant identified by NMED as potentially contributing to regional haze at the Salt Creek Wilderness Area Class I area.[260] NMED has described the facility processes as follows:

> The function of the facility is to process natural gas, including dehydration and sweetening sour natural gas (removing sulfur and CO_2), and also remove lighter hydrocarbons (such as ethane and methane) from the inlet gas stream. The facility is capable of processing approximately 100 MMscf/d of gas.[261]

According to the permit, the plant includes nine two-stroke reciprocating internal combustion engines (RICE) used for compression, four 4-stroke generator RICE, an emergency generator, heaters, sulfur recovery unit and incinerator, storage tanks, an amine unit, and flares.[262] In Targa's four-factor submittal, the company evaluated air pollution controls for the following emission units:

- Cooper-Bessemer 2SLB RICE GMVA-10 (1,350 hp): Units C-01 through C-06
- Cooper-Bessemer 2SLB RICE GMV-10 (1,195 hp): Units C-07 and C-08
- Cooper-Bessemer GMVC-10 (1,800 hp): Unit C-09
- Ingersoll-Rand 4SRB RICE PKVG-8 (780 hp): Units G-01, G-02, G-03
- Amine Gas Treating Unit with Sulfur Recovery Unit and Incinerator: Unit AM-01 / I-01.[263]

The selection of these sources for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hr or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[264] The following provides a review of the company's

[259] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[260] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 1-1.
[261] Title V Operating Permit P111-R2M2 for Saunders Gas Plant at A3.
[262] *Id.* at A6–A7.
[263] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 2-1.
[264] *Id.* at 1-3.

four-factor analyses for the engines listed above. Comments on the four-factor analysis for the amine gas treating unit are provided in Section XXIII further below.

A. Units C-01 through C-09: Natural Gas-Fired 2-Stroke Lean-Burn RICE

Units C-01 through C-06 are Cooper-Bessemer GMVA-10 2-stroke lean-burn compressor engines that were constructed in 1953, each with a capacity of 1,350 hp.[265] These units each have an hourly NOx limit of 32.6 lb/hr and an annual NOx limit of 142.8 tpy.[266]

Units C-07 and C-08 are Cooper-Bessemer GMV-10 2-stroke lean-burn compressor engines that were also constructed in 1953, each with a permitted capacity of 1,195 hp.[267] The two units each have an hourly NOx limit of 28.7 lb/hr and an annual NOx limit of 125.6 tpy.[268]

Unit C-09 is a Cooper-Bessemer GMVC-10 2-stroke lean-burn compressor engine that was constructed in 1953, with a capacity of 1,800 hp.[269] This unit has an hourly NOx limit of 43.2 lb/hr and an annual NOx limit of 189.2 tpy.[270]

1. Evaluation of Baseline NOx Emissions

Targa's four-factor submittal includes unit-specific operating hours based on 2016 emission inventory calculations. Uncontrolled NOx emission rates (g/hp-hr) in Targa's original four-factor analysis are based on a single performance test conducted for each engine in August 2016. The actual emission rates for these units, based on this August 2016 testing, and the allowable NOx emission rates are shown in the table below.[271]

Table 15. Targa Saunders Gas Plant 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Actual Emissions from August 2016 Test Data [g/hp-hr]
C-01	1,350	32.6	11.0	2.05
C-02	1,350	32.6	11.0	10.78
C-03	1,350	32.6	11.0	4.99
C-04	1,350	32.6	11.0	3.87
C-05	1,350	32.6	11.0	7.21
C-06	1,350	32.6	11.0	8.3

[265] Title V Operating Permit P111-R2M2 for Saunders Gas Plant at A6.
[266] *Id.* at A9.
[267] *Id.* at A7. Note, Unit C-08 has a maximum capacity of 1,350 hp and a permitted capacity of 1,195 hp.
[268] *Id.* at A9.
[269] *Id.* at A7.
[270] *Id.* at A9.
[271] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant Appendix B.

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Actual Emissions from August 2016 Test Data [g/hp-hr]
C-07	1,195	28.7	10.9	7.35
C-08	1,195	28.7	10.9	9.13
C-09	1,800	43.2	10.9	5.54

As shown, the actual emission rates for most units, with the exception of C-02 and a few others, are much lower than the units' allowable hourly NOx emission rates, so either the 2016 testing for these units was not conducted while the engines were operating at maximum capacity or the allowable NOx emission rates for these units have been set unreasonably high. Targa's February 2020 Addendum included the results from portable analyzer testing conducted over a few days in August 2016 for the engines at the Saunders Gas Plant, which presumable are the tests used in determining baseline emissions for the four-factor analysis.[272] NMED and Targa should review other performance tests, that are based on EPA Reference Methods, for these units to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. Citing variability in test data, Targa admits that these data are only a snapshot in time and only provide potential emissions based on that snapshot.[273] If testing is only done sporadically and is not done using EPA Reference Methods then it is questionable that such test data truly reflect an accurate projection of emissions expected over the lifetime of the controls being evaluated.

According to the September 2018 Title V renewal application for the Saunders Gas Plant, NOx emissions for units C-01 through C-07 were," calculated using stack test data from 2/22/1994 with a 20% safety factor."[274] Note, permitted emission rates for units C-08 and C-09 were calculated using EPA AP-42 emission factors (Table 3.2-2).[275] The permitted rates for these units (with the exception of unit C-02, but especially for units C-01, C-03, and C-04)—that are based on stack test data—are significantly higher than the NOx emission rates that the company's four-factor cost effectiveness analysis is based upon, even considering the 20% "safety factor", meaning NOx reductions estimates for the various control options considered for these units may be underestimated. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on a more comprehensive estimate of emissions expected in 2028.

1. Use of Low Emission Combustion Technology

Targa describes the LEC control technologies for these 2SLB engines as "Clean Burn Technology (CBT)."[276] In Targa's original submittal it specifically describes the LEC modifications for these

[272] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 18-62.
[273] *Id.* at pdf page 6.
[274] *See* September 2018 Title V Permit Application for Saunders Gas Plant at pdf page 38.
[275] *Id.*
[276] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 2-7.

engines as including pre-combustion chambers and fuel systems to significantly lean the combustion mixture.[277] And Targa notes that the modifications will, "need turbochargers or externally driven blowers added as well."[278] In Targa's February 2020 Addendum, it more specifically describes the technologies included in its updated analysis, including adding a pre-combustion chamber with power cylinder heads, modifications to the fuel system, adding a turbocharger system, and various upgrades to the intercooler system.[279]

Targa determined that this LEC technology is a technically feasible option for the 2SLB RICE units at the Saunders Gas Plant and the cost analysis provided in its four-factor analysis indicates this control could be cost effective for these units, depending on the baseline emission rates and operating schedules. Despite this, Targa concludes these retrofits would be uneconomical.[280]

The cost analysis in Targa's four-factor submittal doesn't necessarily support this claim for these engines, and more importantly, the cost effectiveness of controls may be even more favorable than what is presented by Targa.

In its original November 2019 submittal, Targa presents cost effectiveness of controls for these units that range from $2,754–$277,724 per ton.[281] The capital cost estimates are based on "manufacturer specification" and the annual operating and maintenance costs were provided by Targa.[282] Targa's February 2020 Addendum included an additional control cost analysis based on higher controlled NOx emission rates; Targa also specified that the capital control cost estimates include engineering costs (e.g., equipment / installation, structural, drawings, etc.).[283] The capital cost estimates are similar, at $80—$138 per hp, compared to other capital cost estimates for LEC controls at other similar engines.[284]

The annual hours of operation for these engines varies quite a bit. According to Targa's submittal, the annual hours of operation used in the four-factor analysis are based on 2016 emission inventory data, as shown in the table below:

[277] *Id.*
[278] *Id*.
[279] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 7.
[280] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 7-1.
[281] *Id.* at 3-2. Note, the $277,724/ton figure for unit C-01 represents the cost effectiveness of reducing NOx emissions from a baseline level for this unit (based on a single performance test from 2016) of 2.04 g/hp-hr to a controlled emission rate of 2 g/hp-hr; if this unit were operating at its permitted emission rate (that is also based on performance testing, from 1994) the cost effectiveness of this control would be *significantly* lower (i.e., <$2,000/ton).
[282] *Id.* Appendix B. Note, Targa stated, on pdf page 8 of its February 2020 Addendum, that "the O&M cost included in the analyses were based on Targa's experience operating similar control devices at other sites for expected maintenance and repair."
[283] *See* February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 7 and 114–122.
[284] *See, e.g.,* Four-Factor analyses for Roswell Compressor Station No. 9 (Cooper-Bessemer 4SLB RICE at $90/hp) and Jal No. 3 (Cooper-Bessemer 2SLB RICE at $123/hp).

Table 16. Targa Saunders Gas Plant 2SLB RICE Units
Annual Operation

Unit	Size [hp]	Hours of Operation From 2016 EI Calculations [hr/yr]
C-01	1,350	8,656
C-02	1,350	4,971
C-03	1,350	5,321
C-04	1,350	7,770
C-05	1,350	5,431
C-06	1,350	1,910
C-07	1,195	5,622
C-08	1,195	2,948
C-09	1,800	5,989

In Targa's Addendum, it indicated that annual hours of operation depend on various factors—e.g., including whether units are working, when they require maintenance, etc.—and will vary each year. According to Targa, "each year the engines will operate with different hours of operation and fuel usage."[285] NMED should request operation data for additional years for these units in order to be able to better assess the cost effectiveness of controls for operating schedules that reflect the full range of usage for these engines.

In Targa's original submittal, its cost effectiveness analysis assumes controlled NOx emission rates of 2 g/hp-hr based on "information provided by the engine control vendor."[286] The corresponding NOx emissions reductions in Targa's four-factor analysis for these units range from 2.4% to 81.4%.[287] Note, greater emissions reductions would result from control of units that are operating at levels closer to permitted levels (which are, again, based on test data for Units C-01 through C-07 according to the source's Title V permit application) would mean that the LEC controls would be even more cost effective than what is shown in the original four-factor analysis. And, in fact, Targa states that "[t]he Clean Burn technology will reduce NOx emissions by 81%."[288] For uncontrolled permitted emission rates of 11 g/hp-hr, controlled rates of 2 g/hp-hr would achieve an 81% reduction in NOx emissions, which is exactly what the Clean Burn technology is promising to achieve for all of these units.

As a result of assuming what could be unreasonably low NOx emission rates for baseline uncontrolled emissions from some of the 2SLB engines, i.e., emission rates based on performance test data that show much lower rates than the permitted limits for these units

[285] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 6.
[286] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 3-2.
[287] *Id.* at Appendix B.
[288] *Id.*at 2-7.

(that, according to Targa's Title V permit application, are based on stack data for all units but C-08 and C-09), Targa then also potentially further underestimates the magnitude of potential NOx reductions for these units in its cost effectiveness analysis. Therefore, the potential emissions reductions achieved by retrofitting these units could be much greater than what the four-factor analysis shows due to potential underestimated baseline emissions, hours of operation, and emissions reductions.

With respect to the life assumed for LEC control, Targa assumed a 20-year period.[289] Targa appears to base this on EPA's guidance default for SCR.[290] It's possible that LEC controls can last 25 years, as stated in other cost effectiveness analyses submitted to NMED for LEC controls.[291]
Also, Targa uses an interest rate of 5.5% which is likely high and therefore underestimates annualized costs of control for these engines. As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

Revising Targa's cost effectiveness analyses to address some of these issues, including assuming 1) a 4.7% interest rate (instead of 5.5%), 2) a 25-year life of LEC (instead of an assumed 20-year life), and 3) emissions reductions of 81% based on potential operation at permitted levels (largely based on stack test data), improves cost effectiveness of these controls even further, as shown in the table below. Note, this revised analysis reflects the large range in operating hours, based on 2016 data, which may not be representative of individual engine usage in other years.

Table 17. Cost Effectiveness of LEC at Uncontrolled Saunders Gas Plant Units C-01 through C-09 to Reduce NO_x Levels to 2 g/hp-hr, Assuming 81% Reductions in NOx Emissions, a 4.7% Interest Rate, and a 25-Year Life of Controls, 2019 $

Unit	Size [hp]	Capital Cost of LEC to Reduce NOx from a Permitted Rate of 11 g/hp-hr	Annual O&M Costs	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (81% NOx Reduction)	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC, $/ton
C-01	1,350	$942,500	$100,000	$164,876	8,656	116	$1,422
C-02	1,350	$942,500	$100,000	$164,876	4,971	67	$2,476
C-03	1,350	$942,500	$100,000	$164,876	5,321	71	$2,314
C-04	1,350	$942,500	$100,000	$164,876	7,770	104	$1,584
C-05	1,350	$942,500	$100,000	$164,876	5,431	73	$2,267

[289] *Id.* at Appendix B.
[290] *Id.*
[291] See 2019 Four-Factor submittals for Roswell Compressor Station and Jal No. 3 which both assume 25-year life of controls for LEC.

Unit	Size [hp]	Capital Cost of LEC to Reduce NOx from a Permitted Rate of 11 g/hp-hr	Annual O&M Costs	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (81% NOx Reduction)	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC, $/ton
C-06	1,350	$942,500	$100,000	$164,876	1,910	26	$6,445
C-07	1,195	$945,000	$100,000	$165,048	5,622	66	$2,504
C-08	1,195	$945,000	$100,000	$165,048	2,948	35	$4,776
C-09	1,800	$615,500	$100,000	$142,367	5,989	106	$1,346

The cost effectiveness of LEC control could be significantly lower than what is shown above for engines that operate more frequently than in 2016. Targa stated, in its Addendum, that "[w]ith regards to the engine usage, Targa attempts to use its engines uniformly but this does not mean equally on a calendar year basis."[292] An analysis that assumes each engine operates at the average annual operation across all engines in 2016, which is roughly 5,400 hours per year, would result in cost effectiveness estimates as low as $2,279/ton for unit C-06 and $2,606/ton for unit C-08.

2. Use of SCR.

Targa did not evaluate SCR for these units, primarily because it claimed that, "most 2SLB engines have a poor air-to-fuel ratio that will not support the SCR control."[293] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly because Targa does not consider LEC to be economical.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[294]

[292] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 13.
[293] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 2-8.
[294] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[295] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[296] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

B. Units G-01, G,02, and G-03: Natural Gas-Fired 4-Stroke Rich-Burn RICE

Units G-01 through C-03 are Ingersoll-Rand PKVG-8 4-stroke rich-burn generator engines that were constructed in 1953, each with a capacity of 780 hp.[297] These units each have an hourly NOx limit of 34.2 lb/hr and an annual NOx limit of 149.8 tpy.[298]

1. Evaluation of Baseline NOx Emissions

Targa's four-factor submittal includes baseline unit-specific NOx emission rates in hours per year and tons per year, based on 2016 emission inventory calculations.[299] Operating hours can be calculated based on these data. These baseline NOx emission rates and the allowable NOx emission rates from the source's Title V permit are shown in the table below.[300]

Table 18. Targa Saunders Gas Plant 4SRB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Baseline Emissions [lb/hr]
G-01	780	34.2	19.81
G-02			21.63
G-03			17.4

As shown, the baseline emission rates for all three units are significantly lower than the units' allowable hourly NOx emission rates so, either the baseline emissions for these units is not reflective of operation at maximum capacity or the allowable NOx emission rates for these units

[295] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[296] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[297] Title V Operating Permit P111-R2M2 for Saunders Gas Plant at A7.
[298] *Id.* at A9.
[299] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant Appendix B.
[300] *Id*.

have been set unreasonably high. NMED and Targa should review performance tests for these units to ensure that the actual emission rates can be considered to truly reflect baseline emissions over the lifetime of the controls being evaluated.

According to the September 2018 Title V renewal application for the Saunders Gas Plant, NOx emissions for units G-01 through G-03 were," calculated using stack test data from 2/22/1994 with a 20% safety factor."[301] The permitted rates for these units—that are based on stack test data—are significantly higher than the baseline NOx emission rates that the company's four-factor cost effectiveness analysis is based upon, even considering the 20% "safety factor", meaning NOx reductions estimates for the various control options considered for these units may be underestimated. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on a more comprehensive estimate of emissions expected in 2028.

2. Use of Non-Selective Catalytic Reduction

Targa determined that non-selective catalytic reduction (NSCR) is a technically feasible option for the 4SRB RICE units at the Saunders Gas Plant and the cost analysis provided in its four-factor analysis indicates this control could be very cost effective for these units.[302] Despite this, Targa concludes these retrofits would be uneconomical.[303]

The cost analysis in Targa's four-factor submittal doesn't support this claim for these engines, and the cost effectiveness of controls may be even more favorable than what is presented by Targa.

In its November 2019 submittal, Targa presents cost effectiveness of controls for G-01, G-02, and G-03 of $259/ton, $231/ton, and $287/ton, respectively.[304] The capital cost estimates are based on "information received from engine control vendors or knowledge on the particular equipment."[305] Targa's February 2020 Addendum did not include any revisions to these cost estimates.

The annual hours of operation for these engines is around 7,000 hours per year, based on the pound per hour and ton per year emission rates provided in Targa's submittal:

[301] *See* September 2018 Title V Permit Application for Saunders Gas Plant at pdf page 37.
[302] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 2-6 and 3-2.
[303] *Id.* at 7-1.
[304] *Id.* at 3-2.
[305] *Id.* at B-1.

Table 19. Targa Saunders Gas Plant 4SRB RICE Units Annual Operation Based on 2016 EI Calculations

Unit	Size [hp]	NOx Baseline Emissions [lb/hr]	NOx Baseline Emissions [tpy]	Hours of Operation [hr/yr]
C-01	780	19.81	69.47	7,014
C-02	780	21.63	77.28	7,146
C-03	780	17.14	63.52	7,412

NMED should request operation data for additional years for these units in order to be able to better assess the cost effectiveness of controls for operating schedules that reflect greater usage of these engines, as allowed by current permit limits, e.g., if increased usage would be more representative of typical operation in 2028.

In Targa's submittal, its cost effectiveness analysis assumes controlled NOx emission rates of 0.986 g/hp-hr, based on "a similar unit at the site which is controlled by NSCR."[306] The corresponding NOx emissions reductions in Targa's four-factor analysis for units G-01, G-02, and G-03 are 91.9%, 92.6%, and 90.7% respectively.[307] Note, greater emissions reductions would result from control of these units if they operate at levels closer to permitted levels (which are, again, based on test data), meaning NSCR would be even more cost effective than what is shown in Targa's four-factor analysis. Targa states that, "NSCR controls are typically 90% or greater."[308] For uncontrolled permitted emission rates of 34.2 g/hp-hr, controlled rates of 0.986 g/hp-hr would achieve 97% reduction in NOx emissions. According to EPA's Alternative Control Techniques document for RICE, NSCR vendors quote NOx emission reduction efficiencies of 90 to 98%, resulting in an expected range of controlled NOx emissions from 0.3-1.6 g/hp-hr.[309]

As a result of assuming what could be low NOx emission rates for baseline uncontrolled emissions from these 4SRB RICE, i.e., emission rates based on performance test data that show lower rates than the permitted limits for these units (that, according to Targa's Title V permit application, are also based on stack data), Targa then also potentially further underestimates the magnitude of potential NOx reductions for these units in its cost effectiveness analysis. Therefore, the potential emissions reductions achieved by retrofitting these units could be much greater than what the four-factor analysis shows due to potential underestimated baseline emissions, hours of operation, and emissions reductions.

With respect to the life assumed for LEC control, Targa assumed a 10-year period.[310] Targa does not provide any justification for this assumption for the life of controls. In the NPCA

[306] *Id*. at 3-1.
[307] *Id.* Appendix B.
[308] *Id.*at 2-6.
[309] EPA 1993 Alternative Control Techniques Document for RICE at 2-10 to 2-11.
[310] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant Appendix B.

March 2020 Oil and Gas Four-Factor Report, we assumed a 15-year life of controls in determining the cost effectiveness of NSCR control for 4SRB RICE.[311]

Also, Targa uses an interest rate of 8.25% which is high and therefore underestimates annualized costs of control for these engines. As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

Revising Targa's cost effectiveness analyses to address some of these issues, including assuming 1) a 4.7% interest rate (instead of 8.25%), 2) a 15-year life of NSCR (instead of an assumed 10-year life), and 3) emissions reductions of 97% based on potential operation at permitted levels (largely based on stack test data), improves cost effectiveness of these controls even further, as shown in the table below.

Table 20. Cost Effectiveness of NSCR at Uncontrolled Saunders Gas Plant Units G-01, G-02, and G-03 to Reduce NO_x Levels to 0.986 g/hp-hr, Assuming 97% Reductions in NOx Emissions, a 4.7% Interest Rate, and a 15-Year Life of Controls

Unit	Size [hp]	Capital Cost of NSCR to Reduce NOx from a Permitted Rate [2019$]	Annual O&M Costs [2019$]	Total Annualized Costs of LEC to Reduce NOx to 0.986 g/hp-hr (97% NOx Reduction) [2019$]	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of NSCR [2019$], $/ton
C-01	780	$8,206	$15,308	$16,083	7,014	116	$138/ton
C-02	780	$8,206	$15,308	$16,083	7,146	119	$136/ton
C-03	780	$8,206	$15,308	$16,083	7,412	123	$131/ton

Based on this analysis, it is *extremely* cost effectiveness to retrofit these 4SRB RICE with NSCR and would result in the removal of over 350 tons per year of NOx.

VII. DCP Artesia Gas Plant

The Artesia Gas Plant is a natural gas processing plant that removes condensate, H_2S and CO_2 in an amine unit, and separates natural gas liquids.[312] The plant is located about 15 miles east-southeast of Artesia, New Mexico. It is owned/operated by DCP Midstream. The plant consists of numerous natural gas-fired four-stroke rich-burn RICE units, natural gas-fired four-stroke lean-burn RICE, boilers, amine contactor, flares, and other emissions sources.[313] Of all of those sources of emissions, NMED apparently only requested a four-factor analysis for the flares at

[311] *See* NPCA March 2020 Oil and Gas Four-Factor Report at 20.
[312] 6/27/2017 Title V Permit No. P095-R3 for Artesia Gas Plant at A3.
[313] *Id.* at A6 to A8.

the plant. Notably, all of the four-stroke rich-burn RICE are equipped with nonselective catalytic reduction for NOx control. In Section XXIII further below, we provide comments on the four-factor analysis for the flares associated with the amine unit.

VIII. Harvest Four Corners – Kutz Canyon Gas Plant

Kutz Canyon Gas Plant is a natural gas processing plant that removes ethane and heavier hydrocarbons from natural gas. It is operated by Harvest Four Corners, LLC. The facility is located in San Juan County, about 3.1 miles south of Bloomfield, New Mexico. According to NMED's Statement of Basis for a New Source Review (NSR) permit for the facility, "The Kutz I Plant removes heavier hydrocarbons using a refrigerated lean oil absorption process and was built in 1936. The Kutz II Plant removes heavier hydrocarbons using a cryogenic process and was added to the facility much later, in 1975. The facility operates 8760 hours per year."[314] The Title V operating permit for the facility indicates that the plant includes several natural gas-fired turbines, boilers, several natural gas-fired RICE, heaters, boilers, and flares.[315] In Harvest Four Corner's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Solar Centaur 40 combustion turbines (Units 1-6 and Units 19 and 20)
- Clark HRA-8 two-stroke lean burn RICE (Units 16, 17, and 18)[316]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tons per year (tpy), which is the criteria established by NMED to identify sources subject to four-factor analyses.[317] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

Harvest Four Corners used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[318] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[319] The current bank prime rate is 3.25%.[320] The highest the bank

[314] NMED Statement of Basis, NSR Permit No. 0301-M11 and P097-R3-R3M1, 8/20/2019, at 1.
[315] Title V Operating Permit P097-R3 for Kutz Canyon Processing Plant at A6 to A8.
[316] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 1-2.
[317] *Id.*
[318] *Id.* at Section 8.0 Supporting Documentation.
[319] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[320] https://www.federalreserve.gov/releases/h15/.

prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[321] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[322] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

B. Solar Centaur Natural Gas-Fired Combustion Turbines (Units 1-8 and 19 and 20) at the Kutz Canyon Gas Plant.

The combustion turbines evaluated at the Kutz Canyon Gas Plant are Solar combustion turbines, model Centaur 40 of 3830 hp capacity (Units 1-6) and of 3016 hp capacity (Units 19 and 20).[323] These units were manufactured between 1975 and 1981.[324] Under the terms of the permit, the units are subject to the following hourly and annual emission limits of NOx.

Table 21. Limits from Kutz Canyon Gas Plant Title V Permit for the Units 1-8 and 19-20 Combustion Turbines[325]

Combustion Turbine Unit ID	NOx limit, lb/hr	NOx limit, tpy
1	15.5	67.9
2	15.5	67.9
3	15.5	67.9
4	15.5	67.9
5	15.5	67.9
6	15.5	67.9
19	15.5	67.9
20	15.5	67.9

Units 19 and 20 are also subject to NOx limits of 161.91 ppmv at 15% O_2, pursuant to 40 C.F.R. Part 60, Subpart GG.[326]

Harvest Four Corners evaluated one control option for these combustion turbines: Solar's SoLoNOx combustion system. The company did not evaluate SCR, claiming that it would not operate effectively at the units and that there was not space available for SCR or power

[321] https://fred.stlouisfed.org/series/DPRIME.
[322] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.
[323] Title V Operating Permit P097-R3 for Kutz Canyon Processing Plant at A6.
[324] *Id.*
[325] *Id.* at A9-A10.
[326] *Id.* at A26.

capabilities for such SCR systems.[327] For reasons previously discussed above and in the NPCA Oil and Gas Four-Factor Report, SCR should have been considered as a technically feasible control for these natural gas-fired combustion turbines.

1. Baseline Emissions for the Units 1 – 6 and 19-20 Combustion Turbines.

Harvest Four Corners states that its cost effectiveness analyses for SoLoNOx were based on the 2016 emission inventory submittal.[328] In its cost data sheets in Section 8.0 of its four-factor analysis, the company provided the 2016 emission inventory calculations for the combustion turbines evaluated, but the company did not specify the actual 2016 operating hours for each unit.[329] This is inconsistent with most other four-factor analyses submitted to NMED. Submittal of operating hours is very important for understanding the operating capacity factor of the units, and NMED must require that more specific operational data be made public for the units as part of the four-factor analyses of controls. The company also provided the NOx ppm rate, but it was "converted from 2016 [emission inventory] calculations and data."[330]

Specifically, the company's cost data sheets indicate that the NOx ppm rate for each unit is 67.61 ppm.[331] That NOx concentration was then compared to the NOx emission rate guarantee from SoLoNOx of 25 ppm to determine the percent NOx reduction which was then multiplied by 2016 tpy emissions to determine the NOx removed for the cost effectiveness analysis of SoLoNOx. NMED must require Harvest Four Corners to provide more specific data on how the NOx ppm rate was calculated. Further, each of the units is subject to emission testing requirements of the Title V permit.[332] Such actual emissions tests should be evaluated as well (including the circumstances of the test data) to ensure that the baseline emissions inventory and emission rates are reflective of current actual emissions and emissions expected from the units in 2028. A review of Title V permit application data for the Kutz Canyon Gas Plant on the NMED's Emissions Analysis Tool did not find any other emissions testing data available for these units.

Units 19 and 20 are also subject to NOx limits of 161.91 ppmv at 15% O_2, pursuant to 40 C.F.R. Part 60, Subpart GG as discussed above. This is 2.4 times higher than the 67.61 ppm base NOx rate relied upon by Harvest Four Corners to determine the tons per year of NOx removed due to SoLoNOx. In addition, Units 19 and 20 are different Solar Centaur models than Units 1-6 (T4001 versus T4002). Further, Units 19 and 20 have a lower horsepower rating than Units 1-6. Yet, all eight units were assumed to have the same uncontrolled NOx baseline emission rate. The discrepancies between these two NOx rates need to be addressed by NMED to ensure that

[327] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-4 to 2-5.
[328] *Id.* at 2-10.
[329] *Id.* at Section 8.0, pdf pages 30-37.
[330] *Id.*
[331] *Id.*
[332] Title V Operating Permit P097-R3 for Kutz Canyon Processing Plant at A25.

baseline emissions are based on a valid analysis of actual emissions that are projected to occur in 2028.

2. Evaluation of SoLoNOx for the Combustion Turbines at Units 1-6 and 19-20.

Harvest Four Corners indicates that SoLoNOx can achieve a NOx rate of 25 ppm, which it claims is a reduction of 63% "based on the currently permitted hourly emission rate and turbine stack parameters."[333] This makes clear that Harvest Four Corners is using the 67.71 ppm NOx rate identified in its SoLoNOx cost data sheets along with the 25 ppm NOx rate expected from SoLoNOx to calculate the tons per year NOx reductions expected with SoLoNOx.[334] This statement implies that the NOx baseline emission rate of 67.71 ppm that Harvest Four Corners cites in its SoLoNOx cost data sheets is based on the allowable pound per hour emission limits applicable to each unit. However, in the cost data sheets of Section 8.0 of the Kutz Canyon Gas Plant four-factor analysis, it is stated that the 67.71 ppmv was calculated from the 2016 emission inventory data. Given that this baseline rate forms the basis of the company's claimed NOx removal efficiency with SoLoNOx, NMED must disclose the basis for this base concentration.

In terms of the life of SoLoNOx controls in the cost effectiveness analyses, Harvest Four Corners' analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[335] In the table below, Harvest Four Corners' cost effectiveness analyses of SoLoNOx were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate.

[333] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-3.
[334] A 25 ppm NOx rate reflects 63% NOx reduction from a 67.71 ppm NOx rate.
[335] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

Table 22. Revised Cost Effectiveness of SoLoNOx at Units 1-6 and 19-20 of the Kutz Canyon Gas Plant, to Reflect a 4.7% Interest Rate and a 25 Year Life

Unit	Harvest Four Corners' Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	Harvest Four Corners' Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25 Year Life
1	$61,603	$2,246/ton	$54,666	$1,993/ton
2	$61,603	$2,412/ton	$54,666	$2,141/ton
3	$61,603	$1,983/ton	$54,666	$1,760/ton
4	$78,339	$23,111/ton	$68,433	$20,183/ton
5	$78,339	$2,145/ton	$68,433	$1,873/ton
6	$78,339	$1,910/ton	$68,433	$1,668/ton
19	$61,603	$4,779/ton	$54,666	$4,242/ton
20	$61,603	$2,043/ton	$54,666	$1,813/ton

It must be noted that, for some unexplained reason, the capital cost to install SoLoNOx at Units 4, 5, and 6 was $200,000 higher than the capital cost to install SoLoNOx at the other combustion turbine units. Yet, Units 4, 5, and 6 are the same turbine model as Units 1, 2, and 3 (Model T4002).[336] NMED should evaluate the reason for the higher capital cost of SoLoNOx at Units 4, 5, and 6.

For Unit 4, the unit had very low NOx emissions in 2016 of 5.38 tpy, and thus the cost effectiveness of SoLoNOx was very high at this unit. NMED must ensure that these low NOx emissions at Unit 4 are not anomalous and that the company's baseline emissions for the unit are reflective of expected operations in 2028. With the exception of Unit 4, the cost effectiveness of SoLoNOx at these combustion turbines are in the range of $1760/ton to $4,242/ton to achieve 63% NOx reduction, which is very cost effective.

3. SCR at Units 1-6 and 19-20 at Kutz Canyon Gas Plant

As discussed above, Harvest Four Corners did not evaluate SCR for any of the combustion turbine units, claiming that the exhaust temperatures of the turbines is 1,271 degrees Fahrenheit which the company claims would negatively impact SCR operation, and also that there are site-specific space limitations for installation of SCR. With respect to space limitations, as discussed in Section I.B.3. above, most SCR retrofits have space limitations, because the facility was not likely designed to have space to accommodate SCR. There have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints. For example, for many large coal-fired power plants, SCR reactors

[336] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at Section 8.0.

have been elevated above the air preheaters. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new foundations to make way for the SCR reactor.[337] Thus, before NMED accepts a very brief claim of retrofit difficulty of SCR at any emissions unit being evaluated for reasonable progress controls, it is imperative that NMED ask Harvest Four Corners for a site plan and photos that shows whatever space constraints are being claimed, and that NMED ask the company to consult with SCR vendors for options for SCR installation at the gas turbines.

Depending on the proximity of the gas turbines, it is possible that one SCR reactor could be used by more than one combustion turbine. This would reduce costs and potentially be easier to install at the site. NMED should require all possibilities for SCR installation to be evaluated and documented by Enterprise. The state must not simply discount this highly effective NOx control based on a claim of some retrofit difficulty.

Regarding the company's stated exhaust temperature of 1,271 degrees Fahrenheit, NMED should determine if this is the sustained temperature of the gas turbines or the maximum temperature of the exhaust expected from the Units 1-6 and Unit 19-20 gas turbines. There are options for dealing with high exhaust temperatures of simple cycle turbines to enable the use of SCR. The Buckingham Compressor Station which is proposed to be constructed in Virginia would be equipped with Solar turbines with SoLoNOx, SCR, and cooling air skids.[338] Essentially, this provides for the injection of tempering air at the turbine discharge (upstream of the SCR) to cool the exhaust temperature to the optimal temperature of the SCR catalyst.[339]

Further, these high exhaust temperatures are another reason why NMED should investigate routing more than one combustion turbine exhaust to a common SCR. The routing of the turbine exhausts from multiple turbines to one SCR reactor will allow for some cooling of the exhaust before it enters the SCR. Salt River Project (SRP) is planning to route the flue gas from one boiler at the Coronado Generating Station in Arizona to an existing SCR reactor that had previously been constructed at Coronado Unit 2.[340] It will be a shared SCR system, although it must be noted that the Coronado Unit 1 SCR was designed as a split (two towers within one

[337] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, , available at https://www.onepetro.org/conference-paper/SPE-66501-MS.

[338] *See* May 25, 2018 Permit Application for Altlantic Coast Pipeline LLC, Buckingham Compressor Station, at pdf page 129 (Design Summary), which is available for download at https://www.deq.virginia.gov/Programs/Air/BuckinghamCompressorStationAirPermit/BuckinghamCompressorStationArchivedDocuments.aspx.

[339] *See,* e.g., Buzanowski, Mark A. and Sean P. McMenamin, Peerless Mfg. Co., Automated Exhaust Temperature Control for Simple Cycle Power Plants, available at https://www.powermag.com/automated-exhaust-temperature-control-for-simple-cycle-power-plants/. *See also* Mitsubishi Hitachi Power Systems (MHPS) webpage on SCR systems for simple cycle turbines at https://amer.mhps.com/scr-for-simple-cycle-gas-turbines.html.

[340] *See* January 6, 2020, SRP Newsroom, SRP Selects Operation Plan for Coronado Generating Station, Units 1 and 2 to Run on Existing Selective Catalytic Reduction until 2032, available at https://media.srpnet.com/srp-selects-operation-plan-for-coronado-generating-station/.

reactor) SCR system. So, according to SRP, each unit will have its own SCR within one reactor. Such an approach seems like it could be a viable, more cost effective control option for co-located combustion turbines at compressor stations.

One further reason that Harvest Four Corners identified for SCR not being feasible was due to the electricity needs of the SCR. Harvest Four Corners states that it "does not anticipate that the current electricity availability at Kutz will be sufficient to support the substantial energy burden associated with SCR control" and that "[i]nstallation of this control will require the facility to expand its current power generation."[341] The site has two onsite combustion turbine generators in Units 19 and 20. The Title V Permit states that each of these two generators cannot exceed 2400 kilowatts, and also states that only one unit can operate at any given time.[342] This condition was apparently imposed pursuant to a NSR Permit 0301M9. If this condition was imposed to allow a project to net out of PSD review, then the operational limits cannot be relaxed without the units obtaining a permit as though construction had not yet commenced.[343] But if the units install BACT level controls (SoLoNOx plus SCR), then the burden of obtaining a PSD permit for the units in order to allow both units to produce the needed electricity to operate SCRs may not be substantial. According to EPA's cost spreadsheet for the similar size units to Units 1-6 and 19-20 of the Kutz Canyon Gas Plant, the electricity usage for SCR at the turbines operating at maximum capacity would be approximately 20 kW per hour. Assuming very conservatively that the power for a cooling air skid might double these power needs to 40 kW per hour, the total electricity need for 8 SCR systems (if all combustion turbines being evaluated in this four-factor analysis were equipped with SCR) would very conservatively be 320 kW. If 2400 kW is the maximum capacity of each of Units 19 and 20, this power need reflects 13% of one of the Units 19 or 20 generating units. Given that both generating units are currently not allowed to operate simultaneously under the terms of the permit, it appears that the plant currently has the generating capacity to address worst case electricity needs of SCR systems on each of the eight combustion turbines if the permit was revised to allow for simultaneous operation of both Units 19 and 20.[344]

For all of the reasons discussed above, SCR should not have been excluded from review as a possible NOx control option for Units 1-6 and Units 19-20 at the Kutz Canyon Gas Plant, both by itself and in combination with SoLoNOx.

As discussed above, an SCR installation by itself should be able to reduce emissions to at least 15 ppmv at 15% O_2.[345] That NOx rate reflects a 40% reduction in NOx emissions compared to

[341] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-5.
[342] Title V Operating Permit P097-R3 for Kutz Canyon Processing Plant at A26, Condition A205.C.
[343] *See* 40 C.F.R. 52.21(r)(4).
[344] As previously stated, the ability to allow both Units 19 and 20 to operate simultaneously Depends on the reasons that these operational limitations were imposed at Units 19 and 20. If imposed as "synthetic minor" limits or to allow other projects at the facility to net out review, relaxations in those operational restrictions can be allowed if all regulatory requirements including PSD permitting requirements are addressed.
[345] *See* March 2020 NPCA Oil and Gas Four-Factor Report at 75.

the 25 ppm expected NOx rate with SoLoNOx at Units 1-6 and Units 19-20. Further, a 15 ppmv NOx rate reflects a 78% reduction in NOx from Harvest Four Corners' claimed baseline NOx rate for each unit of 67.61 ppm. Based on the fact that the combustion turbines at the Eunice Gas Plant (Units 17A, 18B, 19A, 25A, and 26A) evaluated for SCR by DCP Midstream are of similar size as the Kutz Canyon Units 1-6 and 19-20 combustion turbines, one would expect SCR to have a similar cost effectiveness. As shown in Table 9 above, the cost effectiveness SCR at the DCP Eunice Gas Plant turbines ranged from $2,600/ton to $3,800/ton (assuming a 4.7% interest rate and 25-year life). Thus, one would expect the similar (or same) model turbine and similar size units at Kutz Canyon to have a similar cost effectiveness of SCR to achieve 15 ppmv at 15% O_2, with the exception of units that are not operated at similar levels as the Eunice turbines such as Kutz Canyon Unit 4.

Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[346] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[347] NMED should require Harvest Four Corners to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

C. Clark HRA-8 Two-Stroke Lean-Burn RICE (Units 16-18) of Kutz Canyon Gas Plant

Units 16, 17, and 18 are Clark HRA-8 two-stroke lean-burn refrigerant compressor engines that were constructed in prior to 1973, each with a nameplate capacity of 830 hp and a site-rated capacity of 723 hp.[348] These units each have an hourly NOx limit of 37.1 lb/hr and an annual NOx limit of 162.0 tpy.[349]

1. Evaluation of Baseline NOx Emissions

Harvest Four Corners' four-factor submittal includes baseline NOx emissions (in tpy) based on 2016 emission inventory calculations; no information is provided on operating hours for these engines. NMED should request more information on the units' current hours of operation and

[346] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.
[347] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.
[348] Title V Operating Permit P1097-R3 for Kutz Canyon Processing Plant at A6-A7.
[349] *Id.* at A9.

actual NOx emissions. The baseline emission rates for these units, based on 2016 emission inventory calculations, and the allowable NOx emission rates are shown in the table below.[350]

Table 23 Harvest Four Corners Kutz Canyon Processing Plant 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [tpy]	NOx Baseline Emissions [tpy]
16	723	162.0	151.37
17	723	162.0	89.63
18	723	162.0	87.5

Without information on operating hours it's not possible to know if baseline NOx emissions from units 17 and 18 are lower than permitted rates because these units operated fewer hours in 2016 or if their hourly emission rates were lower.

According to the May 2019 permit application for the Kutz Canyon Processing Plant, NOx emissions for these units were determined, "using stack test and manufacturer's data."[351] The permitted rates for units 17 and 18—that are based on stack test and manufacturer data—are significantly higher than the NOx emission rates that the company's four-factor cost effectiveness analysis is based upon, meaning NOx reductions estimates for the various control options considered may be underestimated if 2016 operation is not reflective of operation in current and future years. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on a more comprehensive estimate of operating hours and emission rates (e.g., in g/hp-hr or hr/yr) expected in 2028.

2. Use of Low Emission Combustion Technology

Harvest Four Corners describes the LEC control technologies for these 2SLB Clark engines as "Clean Burn Technology (CBT)."[352] According to EPA, "[t]he term "clean-burn" technology is a registered trademark of Cooper Energy Systems and refers to engines designed to reduce NOx by operating at high air-to-fuel ratios."[353] It's not entirely clear what specific technologies are being proposed for the Clark engines at the Kutz Canyon Gas Processing Plant. Harvest Four Corners' submittal discusses, generally, the use of high energy ignition system, turbocharger, and AFRC technologies.[354] EPA described LEC retrofit kits designed to achieve extremely lean

[350] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant Appendix B.
[351] *See* May 2019 Permit Revision Application to NSR Permit 0301-M10 for Kutz Canyon Processing Plant, Section 6 Page 2.
[352] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-6.
[353] EPA AP-42 Chapter 3, Section 3.2 (July 2000) at 3.2-2.
[354] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-7.

air-to-fuel ratios – in order to minimize NOx emissions – as encompassing the following specific retrofit technologies:

- Redesign of cylinder head and pistons to improve mixing (on smaller engines)
- Precombustion chamber (on larger engines)
- Turbocharger
- High energy ignition system
- Aftercooler
- Air-to-fuel ration controller (AFRC)[355]

In order to effectively evaluate a company's assessment of LEC a more precise description of LEC technologies, and associated achievable emission rates is needed. Harvest Four Corners states that Clean Burn Technology is estimated to achieve an 80 to 93% reduction in NOx emissions, depending on engine and loading.[356] Harvest Four Corners assumes an 80% NOx reduction in its four-factor analysis for these engines.

The allowable NOx emission rate for these 723 hp engines, at 37.1 lb/hr, is equivalent to 23.3 g/hp-hr. An 80% reduction in NOx emissions would achieve a NOx level of over 4 g/hp-hr. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[357]

For reference, the following sources of information regarding NOx emission rates specific to Clark engines – both uncontrolled and with LEC technology – are provided here:

- EPA's 2000 RICE Update includes NOx emissions test data for specific engines, including Clark Model TLA-6, 2-stroke, lean-burn, 2,000 hp RICE retrofitted with LEC. According to EPA, six engines retrofitted by a third-party vendor had NOx emission rates ranging from 0.8–1.4 g/bhp-hr, with a mean of 1.0 g/bhp-hr.[358]

- An evaluation by a technical group for the Pipeline Research Council International looked at three of the most representative make / models of 2-stroke lean burn compressor engines: (1) 2,250 hp Cooper GMVH-10; (2) 2,000 hp Clark TLA-6; and (3) 2,500 hp Cooper GMW-10. According to a technical report by the Ozone Transport Commission (OTC) describing this evaluation, "[t]he evaluation concluded that there

[355] EPA, Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500-0508, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance, August 2016, Appendix A at 5-3, *available at:* https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0500-0508 [hereinafter referred to as "2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls"].
[356] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-7, citing EPA's 1993 Alternative Control Techniques document for RICE.
[357] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.
[358] EPA 2000 RICE Update at 4-8.

were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring."[359]

For the units at the Kutz Canyon Processing Plant, a controlled NOx emission rate of 2 g/hp-hr from the uncontrolled allowable NOx emission rate (that is based on stack test and manufacturer data) represents a 91% emissions reduction, which is in the range presented in Harvest Four Corners' four-factor submittal of 80 to 93%.

Harvest Four Corners presents cost effectiveness of LEC controls for these units that range from $1,021–$1,767 per ton.[360] The capital cost estimates of $1 million and annual operating and maintenance cost estimates of $40,000 per year are provided by Harvest Four Corners.[361] These capital cost estimates are a little higher, at $186/hp, compared to other capital cost estimates for LEC controls at other similar engines.[362]

Harvest Four Corners assumes NOx emissions reductions of 80% despite stating that the Clean Burn technologies it would employ are capable of reducing NOx emissions up to 93%.[363] And achieving NOx emission rates of 2 g/hp-hr—as shown by other companies in their four-factor analyses for similar engines at similar costs—would correspond to 91% NOx reductions.[364] These greater emissions reductions would result from control of units that are operating at levels closer to permitted levels (which are, again, based on stack test and manufacturer data) and would mean that the LEC controls would be even more cost effective than what is shown in Harvest Four Corners' original four-factor analysis.

[359] Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, p. 24, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf [hereinafter referred to as "2012 OTC Report"].

[360] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 3-2.

[361] *Id.* Appendix B. Note, these capital cost estimates are in line with other company analyses for similar engines, e.g., Targa's original Four-Factor analysis for Clark HBA-8 engines used capital cost estimates of $950,000. Also, EPA's 2000 RICE Update (p. 5-2) included capital cost estimates for third-party retrofit of a Clark Model HSRA, 2SLB 1,000 hp 8-cylindar engine at a pipeline station of $710,000

[362] *See, e.g.*, November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant cost data for Clark engines at just under $140/hp. *See also* November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant cost data for Clark engines, also under $140/hp.

[363] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-7.

[364] *See* November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 3-3 and November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Monument Gas Plant at 3-2, assuming controlled NOx rates of 2 g/hp-hr for Clark engines.

With respect to the life assumed for LEC control, Harvest Four Corners assumed a 20-year period.[365] This assumption appears to be based on EPA's guidance default for SCR.[366] It's possible that LEC controls can last 25 years, as stated in other cost effectiveness analyses submitted to NMED for LEC controls.[367]

Also, Harvest Four Corners uses an interest rate of 5.5% which is likely high and therefore underestimates annualized costs of control for these engines.[368] As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. Revising Harvest Four Corners cost effectiveness analyses to address some of these issues, including assuming 1) a 4.7% interest rate (instead of 5.5%), 2) a 25-year life of LEC (instead of an assumed 20-year life), and 3) emissions reductions of 91% from baseline emissions, improves cost effectiveness of these controls even further, as shown in the table below.

Table 24. Cost Effectiveness of LEC at Uncontrolled Kutz Canyon Gas Processing Plant Units 16, 17, and 18 to Reduce NO_x Levels to 2 g/hp-hr, Assuming 91% Reductions in NOx Emissions, a 4.7% Interest Rate, and a 25-Year Life of Controls, 2019 $

Unit	Size [hp]	Capital Cost of LEC to Reduce NOx from Baseline Emissions	Annual O&M Costs [2019$]	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (91% NOx Reduction)	Annual Baseline Emissions, tpy	NOx Removed, tpy	Cost Effectiveness of LEC, $/ton
16	723	$1,000,000	$40,000	$134,399	151	138	$790/ton
17	723	$1,000,000	$40,000	$134,399	90	82	$1,334/ton
18	723	$1,000,000	$40,000	$134,399	88	80	$1,367/ton

Harvest Four Corners determined that LEC technology is a technically feasible option for the 2SLB RICE units at the Kutz Canyon Gas Processing Plant and the cost analysis provided in its four-factor analysis, and revised here, confirms this control would be very cost effective. Harvest Four Corners expresses concern that the addition of these controls may be "operationally detrimental" due to the need for a third-party installation. However, no additional specific examples of operational impacts are identified or explained that would necessarily preclude retrofit of these engines. Just because there may be operational issues to

[365] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant Appendix B.
[366] *Id.*
[367] See 2019 Four-Factor submittals for Roswell Compressor Station and Jal No. 3 which both assume 25-year life of controls for LEC.
[368] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant Appendix B.

overcome does not mean that the technology is not feasible or that the resulting emissions reductions are not warranted.

3. Use of SCR

Harvest Four Corners did not evaluate SCR for Units 16, 17, and 18 primarily because it claimed that it was not technically feasible for these engines.[369] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[370]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[371] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[372] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

IX. El Paso Natural Gas Company LLC - Pecos River Compressor Station

The Pecos River Compressor Station is a natural gas compressor station located approximately 12 miles south/southeast of Malaga, New Mexico in Eddy County. It is owned/operated by El

[369] *Id.* at 2-8.
[370] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[371] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[372] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

Paso Natural Gas Company (EPNG). The facility consists of three GE Frame 3 Regenerative Cycle Turbines that each have a capacity of 7,150 hp.[373]

In EPNG's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Natural Gas-Fired Regenerative Cycle Turbine (Units A-01, A-02, and A-03)[374]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[375] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

EPNG used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[376] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[377] The current bank prime rate is 3.25%.[378] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[379] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[380] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

[373] Title V Operating Permit P129R3 for Pecos River Compressor Station at 3.
[374] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 1-2.
[375] *Id.*
[376] *Id.* at 8-6.
[377] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[378] https://www.federalreserve.gov/releases/h15/.
[379] https://fred.stlouisfed.org/series/DPRIME.
[380] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

B. GE Regenerative Cycle Turbines (Units A-01, A-02, and A-03) of Pecos River Compressor Station

As stated above, the three turbines evaluated for controls are GE Frame 3 Regenerative Cycle Turbines with capacity of 7,150 hp. These units were all manufactured in 1953.[381] Under the terms of the permit, the units are each subject to the following hourly and annual emission limits of NOx: 53.1 lb/hr and 232.6 tpy.[382]

EPNG evaluated one control option for these turbines aside from the good combustion practices which the company indicated were currently being utilized at the units. The other combustion control type of controls considered by EPNG included a Lean Head End (LHE) combustion liner, dry low NOx combustors, water/steam injection, but El Paso claimed that based on communications with GE, none of these controls were an option for the Pecos River Compressor Station turbines.[383] Thus, the company only evaluated SCR for the turbines. The following provides comments on the company's four-factor analysis of SCR.

1. Baseline Emissions for the Units A-01, A-02, and A-03 Combustion Turbines.

EPNG states that its cost effectiveness analyses for SCR were based on actual emissions using 2016 stack test data and actual hours of operation from the 2016 emission inventory submittal.[384] In its cost data sheets in Section 8.0 of its four-factor analysis, the company provided summaries of the 2016 test data and the 2016 annual NOx tons per year from each unit, from which the actual operating hours could then be calculated.[385] NMED and EPNG should review other stack tests for these units to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on an estimate of emissions expected in 2028.

2. Evaluation of SCR for the Regenerative Cycle Turbines at Pecos River Compressor Station

EPNG evaluated SCR to achieve 70% reduction in NOx emissions, assuming a 20-year life of SCR.[386] With respect to the lifetime of an SCR, EPA's Control Cost Manual indicates that the life of an SCR at a gas turbine used in an industrial setting like a compressor station.[387] Thus, to be consistent with EPA's current Control Cost Manual chapter on SCR, a 25-year life of SCR should have been assumed.

[381] Title V Operating Permit P129R3 for Pecos River Compressor Station at 5.
[382] *Id.*
[383] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 3-1.
[384] *Id.* at 3-1.
[385] *Id.* at Appendices C and D.
[386] *Id.*, Section 8.0 (at pdf page 31, 36, and 41.
[387] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

EPNG only assumed 70% control with SCR at Units A-01, A-02, and A-03 and cites to an older EPA Fact Sheet on SCR.[388] A review of that EPA fact sheet, which appears to be from 2003, shows that EPA assumed SCR could achieve 70-90% NOx control, and EPA assumed 85% control in its example cost effectiveness analysis of the 2003 Fact Sheet. In EPA's June 2019 updated chapter on selective catalytic reduction in its Control Cost Manual, EPA states that "[t]heoretically, SCR systems can be designed for NOx removal efficiencies [of] close to 100 percent. In practice, commercial coal-, oil-, and natural gas-fired SCR systems are often designed to meet control targets of over 90 percent."[389] EPNG did not provide any other justification for assuming only 70% control with SCR at the Pecos River Compressor station turbines. Indeed, ninety percent control has been the benchmark of SCR NOx removal efficiency expected with SCR including at natural gas-fired combustion turbines.[390] As discussed in NPCA's Oil and Gas Four-Factor Report, in a 2000 analysis of SCR cost effectiveness from an uncontrolled gas turbine, NESCAUM estimated that a 15 ppmvd NOx rate reflective of 90% NOx control (from uncontrolled NOx rates) could be achieved with SCR.[391]

EPNG used the SCR cost spreadsheet that EPA has made available with the Control Cost Manual to estimate SCR costs for its combustion turbines.[392] However, EPNG stated that the exhaust system would require significant modifications to install the catalyst, requiring the stack to be moved and additional ducting.[393] EPNG also states that it believes there is insufficient room within the existing building that houses the turbines, and thus has included costs to modify the turbine housing in the cost analysis.[394] Presumably, to account for some of this, EPNG applied a 1.5 retrofit factor in EPA's SCR cost spreadsheet, and also EPNG also included an additional $2.5 million would be required per combustion turbine for building modifications. However, as previously stated above, there have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints and retrofit difficulties. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new foundations to make way for the SCR reactor.[395] EPA's SCR cost spreadsheet has an option to indicate whether the SCR installation is a new installation or a retrofit, and SPNG selected "retrofit." EPA's SCR chapter in its Control Cost Manual already provides for a 25% increase in cost above the cost of SCR at a new greenfield coal-fired boiler,

[388] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 3-1.
[389] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 5.
[390] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand Curve Reset, prepared for New York Independent System Operator, Inc., at 5 and at 11-12, available at: http://files.brattle.com/files/7644_independent_evaluation_of_scr_systems_for_frametype_combustion_turbines.pdf.
[391] NESCAUM 2000 Status Report at III-21 through III-24 and at III-40 (see references 11, 16, 9, 14, and 15).
[392] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 3-1.
[393] *Id.*
[394] Id.
[395] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, , available at https://www.onepetro.org/conference-paper/SPE-66501-MS.

which is reflected in EPA's SCR cost spreadsheet, because EPA's spreadsheet calls for use of a "0.8" retrofit factor for an SCR installation at a new facility and a "1" retrofit factor for an average SCR retrofit.[396] Further, given that most gas turbines that have retrofitted an SCR reactor likely were not planned or designed for an SCR reactor to be installed, the average retrofit costs that EPA's SCR cost spreadsheet calculates likely take into account some of the difficulties like the need to move the exhaust stack to install the SCR, which would be required for most if into all SCR retrofits to gas turbines.[397] Thus, EPNG was not justified in using both a 1.5 retrofit factor in the SCR cost spreadsheet and also adding $2.5 million in capital costs per unit for compressor building modifications.

With respect to the compressor building modifications, there is one entry made by EPNG into the EPA cost spreadsheet that ultimately defines the size of the SCR reactor, and that is the "base case fuel gas volumetric flow rate factor" which is in terms of ft^3/min-MMBtu/hr. EPNG used a fuel gas volumetric flow rate factor of 35,103.70 ft^3/min-MMBtu/hr for Unit A-01, 50,483.81 ft^3/min-MMBtu/hr for Unit A-02, and 45,807.42 ft^3/min-MMBtu/hr for Unit A-03, which they state is "[c]alculated based on the estimated actual annual fuel consumption and maximum heat input rate."[398] These numbers seem very high in comparison to the values EPA uses for coal-fired boilers for which EPA defines as a constant for fuel type regardless of unit size or actual gas throughput.[399] EPNG's fuel gas volumetric flow rate factors for each combustion turbine are roughly a factor of 100 higher than the fuel gas volumetric flow rate factors used by EPA in its SCR cost spreadsheet for coal-fired boilers. Given that the fuel gas volumetric flow rate factor is used to determine the size of SCR reactor required, it is imperative that NMED ensure that an accurate fuel gas volumetric flow rate factor for natural gas-fired combustion turbines is used in the SCR cost spreadsheet. Presumably, EPNG relied on the reactor size calculations of the spreadsheet to estimate the cost of $2.5 million per SCR installation for modifying the compressor building.

With respect to the cost to modify the compressor building, it appears that EPNG included the $2.5 million per SCR to modify the compressor building with the capital costs of SCR in determining total annual costs of the control.[400] This reflects a 65% increase in the capital cost of SCR that was calculated using a 1.5 retrofit factor. However, while the life of the SCR might be only 25 years, the life of the modifications to the compressor building would likely last as long as the compressor station is in operation, which has been 65 years so far "without any significant deterioration in operating efficiency [of the combustion turbines],[401] and EPNG anticipates that the life of the turbines will be longer than the SCR. Thus, EPNG's approach significantly increases the capital cost and thus the cost effectiveness of SCR for building

[396] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 66.
[397] *See* EPA Control Cost Manual, Section 1, Chapter 2 – Cost Estimation: Concepts and Methodology, at 27.
[398] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at pdf page 32, pdf page 37, and pdf page 42.
[399] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 59, Table 2.6.
[400] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 2-6.
[401] *Id.* at 5-2.

modifications that will have a useful life much longer than the 25 years that EPA assumes for SCRs at industrial facilities.

To attempt to address some of these issues, as well as to revise the cost effectiveness to reflect a 4.7% interest rate and a 25-year life, EPA's SCR cost spreadsheets were used to calculate SCR cost to meet a NOx emission rate of 15 ppmv (reflective of 82 to 86% NOx removal at the Pecos River turbines)[402] assuming a 25-year life and a 4.7% interest rate. No retrofit factor was used in EPA's cost spreadsheets for the reasons previously described, but an analysis was done adding in the company's projected $2.5 million capital cost to the total SCR capital costs. Although the life of the modified compressor building would be much longer than 25 years, the $2.5 million was amortized at the same 25-year life as the SCR. No other changes were made to any of EPNG's inputs to the SCR spreadsheet. The results of these analyses are provided below.

Table 25. Cost Effectiveness of SCR at Pecos River Compressor Station Units A-01, A-02, and A-03 Combustion Turbines, Using a 25-year Life, 4.7% Interest Rate, Retrofit Factor of 1, and EPNG's Assumptions for all Other Inputs

Unit	Assumed NOx Removal Efficiency to meet 15 ppm NOx rate	Capital Cost of SCR (2018 $)	Annual O&M Costs	NOx Removed from 2016 Baseline, tpy	Cost Effectiveness of SCR (2018 $), $/ton	Cost Effectiveness of SCR with Building Modifications (2018 $), $/ton
A-01	82%	$2,535,199	$33,780	42	$5,007/ton	$9,104/ton
A-02	86%	$2,535,199	$43,109	82	$2,676/ton	$4,775/ton
A-03	86%	$2,535,199	$48,533	101	$2,230/ton	$3,934/ton

The above table provides cost effectiveness for SCR by itself at Units A-01, A-02, and A-03 as well as SCR plus the EPNG's estimated $2.5 million capital cost per SCR to modify the compressor building. As the table shows, including EPNG's estimated cost to modify the compressor building for each SCR installation significantly increases the cost effectiveness of SCR. For the reasons stated above, it is imperative that NMED ensure that the costs to modify the compressor building were appropriately estimated. Regardless, for at least Units A-02 and A-03 which operated more than Unit A-01 in 2016, SCR should still be considered cost effective even with $2.5 million in costs per SCR to modify the building. And if 2016 operating hours were lower than typical operation for Unit A-03, SCR should be considered cost effective for that unit as well.

[402] This was determined by converting EPNG's stated uncontrolled lb/MMBtu NOx rates to ppm NOx rates using the conversions of EPA's 1993 ACT for Gas Turbines (*See* EPA, 1993 ACTfor Gas Turbines at Appendix A which has conversion equations for natural gas-fired combustion turbines) and determining the percent NOx reduction efficiency to achieve a 15 ppmv NOx limit (equivalent to ~0.060 lb/MMBtu).

EPNG expressed concerns with the ammonia reagent used in an SCR system.[403] As discussed in the NPCA Oil and Gas Four-Factor Report, the primary concerns with ammonia releases are when anhydrous ammonia is used for the reagent.[404] EPNG assumed 29% aqueous ammonia in its SCR analyses.[405] When aqueous ammonia, or urea, is used, the hazards from transporting and storing pressurized ammonia don't apply. SCR has been installed at numerous industrial facilities across the U.S. There are well-established protocols and procedures for safely transporting, storing, and using anhydrous ammonia at facilities that use that reagent in their SCR systems.

X. DCP Midstream - Linam Ranch Gas Plant

The Linam Ranch Gas Plant is a natural gas processing plant located about seven miles west of Hobbs, New Mexico in Lea County. The plant is owned/operated by DCP Midstream LP. According to the Title V permit for the plant, the facility processes natural gas by removing hydrogen sulfide, water, and carbon dioxide from field gas and separates natural gas liquids from the field gas stream.[406] NMED's Statement of Basis for the plant's Title V permit describes the plant as follows: "The plant consists of an Inlet Receiving System, Amine Treater, Acid Gas Injection Well, Inlet Compression and Dehydration System, Cryogenic/Turbo Expander Plant with external Propane Refrigeration, Residual Compression, and Product Sales for Residue Gas, NGL Liquids, Stabilized Oil, Slop Oil, and Molten Liquid Sulfur."[407] The plant include Fuel Gas Systems, Instrument and Starting Air Systems, a Heat Medium (Hot Oil) System, Cooling Towers, Process Flare, Acid Gas Flare, and Drain Systems. Processing operations at the plant include chemical reaction processes, thermodynamic processes, and physical processes."[408]

According to the Title V permit, the Linam Ranch Gas Plant includes several 2-stroke lean burn RICE, several natural gas-fired turbines, boilers, a heater, gas sweetening equipment (amine unit, sulfur recovery unit (SRU) incinerator, acid gas and SRU flares), and other emission units.[409] In DCP Midstream's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Clark TLA-6 2-stroke lean-burn RICE: Units 6-11
- Solar Centaur Turbines: Units 29, 30, 31, and 32B.[410]

[403] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 5-1.
[404] March 2020 NPCA Oil and Gas Four-Factor Report at 80. *See also* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 15.
[405] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at pdf page 32, pdf page 37, and pdf page 42.
[406] Title V Operating Permit P094-R2 for Linam Ranch Gas Plant at 3.
[407] NMED Statement of Basis – Narrative, Title V Permit, Linam Ranch Gas Plant, March 2015, at 1.
[408] NMED Statement of Basis – Narrative, Title V Permit, for Permit Nos. 0044-M-10-M10R6 and P086-R3, at 1.
[409] Title V Operating Permit P094-R2 for Linam Ranch Gas Plant at 7-8.
[410] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Linam Ranch Gas Plant at 1-2.

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[411] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

DCP Midstream used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[412] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[413] The current bank prime rate is 3.25%.[414] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[415] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[416] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

B. Clark TLA Two-Stroke Lean Burn RICE (Units 6-11) of the Linam Ranch Gas Plant

Units 6 and 7 are Clark TLA-6 two-stroke lean-burn RICE that were constructed in 1974, each with a capacity of 2,000 hp.[417] Units 6 and 7 each have an hourly NOx limit of 39.3 lb/hr; units 6-11 have a combined annual NOx limit of 566 tpy.[418]

Units 8 through 11 are Clark HBA-6 two-stroke lean-burn RICE that were constructed in 1951, each with a capacity of 1,267 hp.[419] Units 8 through 11 each have an hourly NOx limit of 47.5 lb/hr; units 6-11 have a combined annual NOx limit of 566 tpy.[420]

[411] *Id.*
[412] *Id.* at Section 8.0 Supporting Documentation.
[413] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[414] https://www.federalreserve.gov/releases/h15/.
[415] https://fred.stlouisfed.org/series/DPRIME.
[416] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.
[417] Title V Operating Permit P094-R2 for Linam Ranch Gas Plant at 7.
[418] *Id.* at 9.
[419] *Id.* at 7.
[420] *Id.* at 9.

1. Use of Low Emission Combustion Technology

DCP Midstream determined that, "…clean burn technology retrofits are physically possible yet deemed technically infeasible for the engines at Linam. The aforementioned available clean burn control technologies are incapable of being retrofit on the existing 70-year-old engines on site."[421] It's true that Units 8 through 11 are 69 years old but units 6 and 7 are newer units and, in fact, units of similar ages to all of these units at Linam Ranch have demonstrated LEC retrofit technology to reduce NOx emissions. For example, Targa's Eunice and Monument gas plants operate Clark engines of similar vintage to the ones at Linam Ranch and submitted four-factor analyses to NMED for Clean Burn technology retrofits, which Targa deemed to be feasible control options.[422]

More generally, the following additional information regarding NOx emission rates specific to Clark TLA model engines – both uncontrolled and with LEC technology – are provided here:

- EPA's 2000 RICE Update includes NOx emissions test data for specific engines, including Clark Model TLA-6, 2-stroke, lean-burn, 2,000 hp RICE retrofitted with LEC. According to EPA, six engines retrofitted by a third-party vendor had NOx emission rates ranging from 0.8–1.4 g/bhp-hr, with a mean of 1.0 g/bhp-hr.[423]

- An evaluation by a technical group for the Pipeline Research Council International looked at three of the most representative make / models of 2-stroke lean burn compressor engines: (1) 2,250 hp Cooper GMVH-10; (2) 2,000 hp Clark TLA-6; and (3) 2,500 hp Cooper GMW-10. According to a technical report by the Ozone Transport Commission (OTC) describing this evaluation, "[t]he evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring."[424]

- In 2002, EPA collected data on emission rates of lean burn engines that have been retrofitted with LEC, including data from several state agencies for specific engine

[421] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Linam Ranch Gas Plant at 2-9.
[422] Targa's Eunice Gas Plant operates several Clark BA-6 and HBA-T8 2SLB RICE constructed in 1984 and capable of being retrofit with LEC technology. Targa's Monument Gas Plant operates several Clark RA-6, RA-8, and HRA-8 2SLB RICE constructed in 1956 and 1969 and capable of being retrofit with LEC technology.
[423] EPA 2000 RICE Update at 4-8.
[424] Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, p. 24, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf [hereinafter referred to as "2012 OTC Report"].

models.[425] Test results for 20 Clark TLA engines ranged from 0.4 to 2.9 g/hp-hr, with an average controlled NOx rate of 1.5 g/hp-hr.[426]

The above references don't specify the age of the engines retrofit with LEC technology but NMED should require DCP Midstream to further explore additional third-party vendor options for retrofitting these units.

A recent Interstate Natural Gas Association of America (INGAA) Report provides some information on Clark TLA engine stock components and retrofit modification / upgrade options.[427] Examples from this report include: upgrading stock turbocharger and stock intercooler systems; upgrading stock low pressure direct fuel systems to high pressure fuel injection and control systems; and upgrading controls for the stock fuel system.[428] Based on the information in this report, Clark TLA model engines come equipped with a single turbo, an intercooler system, and a low pressure direct fuel system. The INGAA report evaluated controls for various regulatory scenarios that would achieve NOx emission levels in the 1–3 g/hp-hr range.[429]

LEC retrofit costs specific to Clark TLA model engines are reported in the INGAA report, ranging from $300–$600 per hp, for upgrades to the scavenging, intercooler, and fuel systems.[430] The INGAA report doesn't specify what year the cost data are from so we assume it reflects the timeframe of the report, or 2017$. Using these cost data, we can estimate the cost effectiveness of retrofitting Units 6 through 11 at the Linam Gas Plant. Retrofit cost estimates using INGAA's cost estimate would range from $600,000–$1,200,000 for the 2,000 hp units 6 and 7 and $380,000–$760,200 for the 1,267 hp units 8 through 11, in 2017$. Using the Chemical Engineering Plant Cost Indices, these costs would increase to $640,000–$1,275,000 and $400,000–$800,000, in 2018$.[431] It's not clear if operating costs are included in these INGAA cost estimates; to be conservative, annual operating costs of the LEC controls are assumed to be 15% of capital costs.[432]

[425] *See* EPA Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call (October 2003) at 15, *available at:* http://www.valleyair.org/workshops/postings/2011/8-18-11-rule4702/R4702%20APPF.pdf

[426] *Id.* Table 4.

[427] INGAA, Report No. 2016-6, *Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOx Control for Natural Gas Transmission and Storage Compressor Drivers* (December 2017), *available at:* https://www.ingaa.org/File.aspx?id=33789.

[428] *Id. See, e.g.,* Table 6 at 18.

[429] *Id.* at 23.

[430] *Id.*

[431] Based on multiplying the cost estimate from the 2017 INGAA report by the ratio of the CEPCI indices for 2018 to 2017 (603.1/567.5).

[432] This assumption is consistent with cost data provided for the October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, however it results in much higher O&M costs than those used in Targa's (Eunice, Monument, and Saunders Gas Plants) and Harvest Four Corners' (Kutz Canyon Gas Plant) four-factor analyses—which ranged from $40,000/yr to $100,000/yr—and than those used for ETC Texas Pipeline's Jal No. 3 Gas Plant, which assumed O&M costs would be 13% of capital costs.

EPA has examined source test data from large natural gas-fired lean burn engines and has affirmed that these data support an uncontrolled emission rate from these engines, generally, of 16.8 g/hp-hr.[433] More specifically, these source test data include individual data for three Clark TLA engines with uncontrolled emission rates of 16 g/hp-hr and two Clark TLA-10 engines with uncontrolled emission rates of 7 g/hp-hr.[434] The allowable hourly NOx emission rates for the units at Linam Ranch are equivalent to 9 g/hp-hr (for units 6 and 7) and 17 g/hp-hr for units 8 through 11. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[435] Retrofitting LEC technology on the units at Linam Ranch to achieve a controlled NOx rate of 2 g/hp-hr reflects a 78-88% emissions reduction from the sources' allowable NOx rates. Baseline NOx emissions for these units at Linam Ranch were not provided in DCP Midstream's four-factor submittal.
The cost effectiveness of retrofitting these engines with LEC to meet a 2 g/hp-hr NOx emissions rate, based on uncontrolled emission rates (no higher than what is permitted for this source), is presented in the table below. Since the operating schedule for these engines at the Linam Gas Plant is unknown we present cost effectiveness for 2,000 and 4,000 operating hours per year; the permitted annual NOx emission rate cap for these units of 566 tons per year indicates that the units likely wouldn't operate much more than 4,000 hours per year, on average. Note, this analysis uses an interest rate of 4.7%, reflective of current and likely near future interest rates.[436] Further note, the LEC controls are assumed to last 25 years, consistent with other cost effectiveness analyses submitted to NMED for LEC controls.[437]

[433] *See* EPA Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call (October 2003) at 5, *available at:* http://www.valleyair.org/workshops/postings/2011/8-18-11-rule4702/R4702%20APPF.pdf.
[434] *Id*. at 6 and 7.
[435] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.
[436] As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.
[437] See 2019 Four-Factor submittals for Roswell Compressor Station and Jal No. 3 which both assume 25-year life of controls for LEC.

Table 26. Cost Effectiveness of LEC at Uncontrolled Linam Gas Plant Units 6 through 11 to Reduce NO_x Levels to 2 g/hp-hr, Assuming a 4.7% Interest Rate and a 25-Year Life, 2018$

Unit	Capital Cost of LEC to Reduce NOx from Uncontrolled Rate	Annual O&M Costs (assume 15% of Capital Costs)	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (78-88% NOx Reduction)	NOx Removed, tpy operating 2,000 hr/yr	Cost Effectiveness of LEC operating 2,000 hr/yr, $/ton	NOx Removed, tpy operating 4,000 hr/yr	Cost Effectiveness of LEC operating 4,000 hr/yr, $/ton
6	$640,000–$1,275,000	$96,000–$191,000	$140,000–$280,000	31	$4,521/ton—$9,042/ton	62	$2,260/ton–$4,521/ton
7	$640,000–$1,275,000	$96,000–$191,000	$140,000–$280,000	31	$4,521/ton—$9,042/ton	62	$2,260/ton–$4,521/ton
8	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	41	$2,138/ton—$4,277/ton	83	$1,069/ton–$2,138/ton
9	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	41	$2,138/ton—$4,277/ton	83	$1,069/ton–$2,138/ton
10	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	41	$2,138/ton—$4,277/ton	83	$1,069/ton–$2,138/ton
11	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	41	$2,138/ton—$4,277/ton	83	$1,069/ton–$2,138/ton

LEC at these units would be even more cost effective than what is shown if retrofits at these engines could meet even lower NOx emission levels, less than 2 g/hp-hr. DCP Midstream indicated that retrofitting engines at the Linam Gas Plant is physically possible and NMED should require that the company solicit specific vendor quotes in order to assess the cost effectiveness of reducing NOx emissions from these engines, as has been done by other companies in New Mexico with similar engines.

2. Use of SCR

DCP Midstream did not evaluate SCR for Units 6 through 11 primarily because it claimed that it was not technically feasible for these engines.[438] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be

[438] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Linam Ranch Gas Plant at 2-9.

summarily dismissed as not feasible for these engines, particularly because DCP Midstream has not found LEC to be a cost effective NOx reduction strategy for these units.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[439]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[440] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[441] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

C. Solar Centaur Natural Gas-Fired Combustion Turbines (Units 29, 30, 31, and 32B) of the Linam Ranch Gas Plant.

The combustion turbines evaluated at the Linam Ranch Gas Plant are Solar combustion turbines of the following models, horsepower capacities, and manufacture date:[442]

Unit 29	Solar T-70	77.6 MMBtu/hr	1995
Unit 30	Solar Taurus T-70	73.95 MMBtu/hr	1995
Unit 31	Solar T4700	36.8 MMBtu/hr	1995
Unit 32B	Solar T4000	36.2 MMBtu/hr	1979

The units are all subject to NOx limits in 40 C.F.R. Part 60, Subpart GG, but those specific limits are not detailed in the Title V permit.[443] Under the terms of the permit, the units are also subject to the following hourly and annual emission limits of NOx.

[439] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[440] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[441] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[442] *See* Title V Operating Permit P094-R2 for Linam Ranch Gas Plant at 8.
[443] *Id.* at 10.

Table 27. Limits from DCP Midstream Title V Permit for the Linam Ranch Plant Combustion Turbines[444]

Combustion Turbine Unit ID	NOx limit, lb/hr	NOx limit, tpy
29	11.8	51.8
30	11.3	49.3
31	26.0	114
32B	23.7	103.9

DCP Midstream evaluated two control options for these combustion turbines: Solar's SoLoNOx combustion system and SCR.

1. Baseline Emissions for Units 29, 30, 31, and 32B.

DCP Midstream states that its cost effectiveness analyses for SoLoNOx and SCR were based on 2016 turbine operating hours multiplied by the permitted potential to emit rate (lb/hr).[445] However, the company did not provide the operating hours or this calculation of 2016 emissions in its four-factor analysis. The company also provided analyses of cost effectiveness of controls "[u]sing the actual emissions testing data (NSPS KKKK) for these turbines, rather than [potential to emit]."[446] However, the company provided no data in its four-factor analyses as to what the actual emission testing results were. Further confusing the matter is that, based on a review of the permit, the turbines are not subject to NSPS KKKK. Instead, all of the units are subject to NSPS Subpart GG.[447] A review of Title V permit application data for the Linam Ranch Gas Plant on the NMED's Emissions Analysis Tool did not find any other emissions testing data available for these units. NMED must make available whatever test data is being relied on to reflect actual emissions of these five combustion turbines if NMED intends to rely on the cost effectiveness analyses provided in a footnote of DCP Midstream's four-factor analysis. NMED should present information on the test data so the circumstances of the stack tests can be reviewed.

According to DCP Midstream's four-factor analysis, its 2016 emission inventory is based on its actual operating hours multiplied by its hourly NOx emission limit.[448] Given that this is how DCP Midstream reports actual emissions for the combustion turbines to NMED and in the absence of testing documentation to ensure that the test data DCP relies on for its alternative baseline analysis reflects actual emissions at all levels of operation of the combustion turbines, it seems most appropriate to use the data that DCP has been using for its emission inventory. NMED should require that DCP identify the operating hours of each unit that it has assumed for the combustion turbines.

[444] *Id.* at 9.
[445] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Linam Ranch Gas Plant at 3-11, fn 23.
[446] *Id.*
[447] Title V Operating Permit P094-R2 for DCP Midstream Linam Ranch Gas Plant at 6, Table 103.A.
[448] *Id.* at 3-11.

2. Evaluation of SoLoNOx for the Combustion Turbines at 29, 30, 31, and 32B.

DCP Midstream states that SoLoNOx can achieve an "overall reduction efficiency of 55%-80%...for the turbines located at this facility using this technology in comparison to permitted [potential to emit]."[449] Specifically, DCP Midstream evaluated SoLoNOx to meet a 15 ppm NOx rate at Units 29 and 30 and a 25 ppm NOx rate at Units 31 and 32B.[450]

In terms of the life of SoLoNOx controls in the cost effectiveness analyses, DCP's analysis assumed a 20 year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[451] In the table below, DCP Midstream's cost effectiveness analyses of SoLoNOx were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate.

Table 28. Revised Cost Effectiveness of SoLoNOx at Units 29, 30, 31 and 32B of the DCP Midstream Linam Ranch Gas Plant, to Reflect a 4.7% Interest Rate and a 25 Year Life

Unit	DCP's Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	DCP's Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25 Year Life
29	$605,743	$21,278/ton	$602,950	$20,642/ton
30	$618,799	$23,829/ton	$616,006	$23,720/ton
31	$269,048	$3,100/ton	$248,594	$2,865/ton
32B	$268,805	$12,765/ton	$248,151	$11,794/ton

The cost effectiveness of SoLoNOx at Units 29 and 30 are very high, because according to DCP Midstream's four-factor submittal, the units' current NOx rates are 33-35 ppm, and thus SoLoNOx to reduce the units' NOx emissions to 15 ppm will only reduce emissions by 55-57%. For Unit 31, SoLoNOx is much more cost effective at $2,865/ton, as the company's four-factor submittal shows that SoLoNOx at Unit 31 would reduce NOx by 78%. For Unit 32B, the cost effectiveness is higher despite SoLoNOx being projected to reduce NOx by 76% because the unit had low actual emissions in 2016 (which appears to be due to low operating hours). NMED should ensure that the 2016 emissions and operational data that is being relied on for the cost effectiveness analyses is reflective of historical operations and projected operations in 2028 before discounting a highly effective control as not cost effective.

[449] *Id.* at 2-4.
[450] *Id.* at pdf page 29, pdf page 34, pdf page 39, and pdf page 44.
[451] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

3. Evaluation of SCR for Units 29, 30, 31, and 32B of the DCP Midstream Linam Ranch Gas Plant.

DCP Midstream evaluated SCR as a technically feasible control option for the Solar Centaur gas combustion turbines of Units 29, 30, 31, and 32B of the DCP Midstream Linam Ranch Gas Plant. DCP Midstream used EPA's SCR cost spreadsheet made available with EPA's Control Cost Manual.[452]

DCP Midstream only assumed 70% control could be achieved with SCR at Units 29, 30, 31, and 32B, even though the company indicated that SCR could achieve up to 90% control.[453] As presented NPCA's Oil and Gas Four-Factor Report, NESCAUM assumed 90% control with SCR in its 2000 Status Report to control small gas turbines down to 15 ppmv.[454] However, for Units 29 and 30, a 15 ppm NOx rate with SCR only reflects 55-57% control. As discussed in Section I.C.2 above, NOx rates as low as 3.75 ppm have been permitted for gas turbines with SoLoNOx and SCR.[455] Thus, to reflect the capabilities of SCR at Units 29 and 30, a much lower NOx emissions rate should have been evaluated for these units. For this report, the EPA's SCR cost spreadsheet was thus used with almost all of the same data inputs as used by DCP Midstream, but assuming a NOx rate equivalent to about an 85% NOx reduction would be met at the units (approximately a 5 ppm NOx emission rate at Units 29 and 30 and 15 ppmv NOx emission rate at Units 31 and 32B). The only other changes made to DCP's SCR spreadsheet inputs were to assume a longer life of the SCR of 25-years[456] and a 4.7% interest rate (instead of DCP's assumed 20-year life of SCR and 5.5% interest rate). The table below provide the estimated cost effectiveness of SCR to achieve 85-87% control at Units 29, 30, 31, and 32B of the DCP Midstream Linam Ranch Gas Plant.

[452] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Linam Ranch Gas Plant at 3-12.
[453] *Id.* at 2-6.
[454] NPCA March 2020 Oil and Gas Four-Factor Report at 74-75. *See also* NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15), available at http://www.nescaum.org/documents/nox-2000.pdf/view.
[455] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.
[456] EPA's Control Cost Manual indicates that SCR at industrial units has a life of 25-years. *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

Table 29. Cost Effectiveness of SCR to Achieve ~85% NOx Reduction (5 ppmv at Units 19 and 20 and 15 ppmv at Units 21 and 22B) at the Linam Ranch Gas Plant, Assuming a 25-Year Life of SCR and a 4.7% Interest Rate

Linam Ranch Unit #	Capital Cost of SCR	Annual Operational and Maintenance Costs of SCR	Annualized Cost of SCR to Achieve 85-87% NOx control	NOx Emission Reductions, tpy	Cost Effectiveness of SCR to Achieve 85-87% Control (at 4.5% interest rate and 25 year life)
19	$3,029,516	$50,364	$261,605	44	$5,991/ton
20	$2,935,376	$47,267	$252,025	39	$6,395/ton
21	$1,864,898	$34,660	$165,705	97	$1,706/ton
22B	$1,845,408	$18,703	$148,406	24	$6,195/ton

As shown by a comparison of Table 29 to Table 28 above, SCR at the Linam Ranch Gas Plant Units 19, 20, 21, and 22B is actually more cost effective than SoLoNOx at the units and SCR can achieve greater levels of NOx reductions. SCR could be even more cost effective if there are opportunities to share an SCR between two or more combustion turbines.
Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[457] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[458] NMED should require DCP Midstream to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

XI. ETC Texas Pipeline – Jal No. 3 Gas Plant

The ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant is located in Lea County. NMED has described the facility processes as follows:

> The function of the facility is to treat and process natural gas. The facility consists of natural gas compression units, amine-sweetening units, a sulfur unit, an acid

[457] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.
[458] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.

gas reinjection system, various storage tanks, fugitive emissions, and three flares.[459]

According to the permit, the plant includes several 2-stroke and 4-stroke lean-burn reciprocating internal combustion engines (RICE), boilers, heaters, amine sweetening units, vapor recover unit and thermal oxidizer, flares, and tanks.[460] In ETC Texas Pipeline's four-factor submittal, the company evaluated air pollution controls for the following emission units:

- Cooper-Bessemer 2SLB RICE GMV-10T5: Units 4A and 5A.[461]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[462] The following provides a review of the company's four-factor analyses.

A. Units 4A and 5A: Cooper-Bessemer GMV-10T5 2-Stroke Lean-Burn RICE

Units 4A and 5A are two-stroke lean-burn RICE that were constructed in 1948, each with a capacity of 1,100 hp.[463] The units each have an hourly NOx limit of 27.9 lb/hr and an annual NOx limit of 122.0 tpy.[464] The operating hours for these units, based on 2016 emissions inventory data are 560 hours per year for unit 4A and 4,290 hours per year for units 5A.[465]

1. Use of Low Emission Combustion Technology

ETC Texas Pipeline describes units 1A, 2A, and 3A as the same Cooper-Bessemer GMV-10T5 engines but currently operating with low emission control technology.[466] These engines were retrofit in 2007 by Cameron Compression Systems including new power cylinder heads, gas ignitors, a high efficiency turbocharger, and guaranteeing a controlled NOx emission rate of 2 g/hp-hr.[467]

ETC Texas Pipeline assumes a controlled NOx emission rate from LEC retrofits on units 4A and 5A of 1 g/hp-hr and estimates this represents an 81–89% reduction from baseline NOx emission rates that are based on the 2016 emissions inventory.[468] The permitted maximum hourly NOx emission rate of 27.9 lb/hr for these units is significantly higher than the 2016 emissions

[459] Title V Operating Permit P090-R3 for Jal #3 Gas Plant at A3.
[460] *Id.* at A7–A9.
[461] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at 2 and Appendix B.
[462] *Id.* at 2.
[463] Title V Operating Permit P090-R3 for Jal #3 Gas Plant at A7.
[464] *Id.* at A10.
[465] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant Appendix B.
[466] *Id.* at 2.
[467] *Id.* at 4 and Appendix A (*see* pdf page 26).
[468] *Id.* at 5.

inventory data used for baseline emissions, especially for unit 5A. The allowable hourly NOx emission rate is equivalent to 11.5 g/hp-hr for these 1,100 hp engines. The source's Title V renewal application provided details on the basis for the uncontrolled NOx emission rate as stack test data, with data provided for all five Cooper-Bessemer GMV-10TF engines. The stack test data for units 4A and 5A are shown in the table below, along with the baseline emissions used in the four-factor analysis (that are based on 2016 emissions inventory calculations):

Table 30. ETC Texas Pipeline Jal No. 3 Gas Plant 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Stack Test Data from Title V Permit Application [g/hp-hr]	NOx Baseline Emissions from August 2016 EI [g/hp-hr]
A4	1,100	27.9	11.5	6.2–6.8	9.4
A5	1,100	27.9	11.5	7.2–8.2	5.1

Assuming a controlled NOx emission rate for LEC of 1 g/hp-hr, emissions reductions range from 84–89% for unit A4 and from 81–88% for units A5. ETC Texas Pipeline assumed 89% control for unit A4 and 81% control for unit A5. If unit A5 operates at a higher emission rate than in 2016—one that is more reflective of the emission rate from the stack testing completed for the source's Title V Renewal Application—then the emissions reductions would be greater than what was assumed in the four-factor analysis.

It's possible that the controlled emission rate with LEC for these specific engines could be even lower that 1 g/hp-hr. For reference, the following additional sources of information regarding NOx emission rates specific to Cooper-Bessemer GMV model engines – both uncontrolled and with LEC technology – are provided here:

- EPA's 2000 RICE Update includes NOx emissions test data for specific engines, including Cooper-Bessemer GMV-10C, 2-stroke, lean-burn, 1,100 hp RICE retrofitted with LEC. Tested at 0.61 g/bhp-hr.[469]

- An evaluation by a technical group for the Pipeline Research Council International looked at three of the most representative make / models of 2-stroke lean burn compressor engines: (1) 2,250 hp Cooper GMVH-10; (2) 2,000 hp Clark TLA-6; and (3) 2,500 hp Cooper GMW-10. According to a technical report by the Ozone Transport Commission (OTC) describing this evaluation, "[t]he evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring."[470]

[469] EPA 2000 RICE Update at 4-8.
[470] 2012 OTC Report at p. 24.

LEC controls at unit 5A would be even more cost effective if the baseline emission rate is more in line with the stack test data provided in the source's Title V Renewal Application (i.e., reflective of 88% control).

ETC Texas Pipeline states that units 4A and 5A are backup engines that operate, on average, 25-50% of the time each year.[471] The four-factor analysis is based on operating hours from the 2016 emissions inventory of 560 hours for unit 4A and 4,290 hours for unit 5A, or 6% and 50% operation, respectively. Therefore, the cost effectiveness of LEC controls at unit 4A would be more favorable than what is shown in the four-factor analysis for operation between 25-50%. Revising ETC Texas Pipeline's cost effectiveness analyses to address some of these issues, including assuming 1) 88% control of NOx at unit 5A, and 2) unit 4A operating 50% of the year, results in more favorable cost effectiveness of these controls, as shown in the table below.

Table 31. Cost Effectiveness of LEC at Uncontrolled Jal No. 3 Gas Plant Units 4A and 5A to Reduce NO_x Levels to 1 g/hp-hr, Assuming 89% Control (Unit 4A) and 88% Control (Unit 5A) and Unit 4A Operating 50% of the Year, 2019 $

Unit	Size [hp]	Capital Cost of LEC (vendor quote)	Annual O&M Costs (13% of Capital Costs)	Total Annualized Costs of LEC to Reduce NOx to 1 g/hp-hr (88-89% NOx Reduction)	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC, $/ton
4A	1,100	$798,355	$103,786	$135,720	4,380	45	$3,042/ton
5A	1,100	$798,355	$103,786	$135,720	4,290	37	$3,624/ton

Note, the cost effectiveness of LEC controls would be more favorable for both units if they were able to meet controlled emission rates below 1 g/hp-hr, which, as discussed earlier, has been demonstrated for other LEC retrofits for similar engines.

2. Use of SCR

ETC Texas Pipeline also evaluated SCR as a control for the two-stroke lean burn engines at Jal No. 3. The company did identify concerns with applicability of SCR to the two-stroke lean burn units including reagent injection control, exhaust temperature requirements, variations in the exhaust NO/NO_2 ratio, and engine oil carryover harming the SCR catalyst.[472] In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by

[471] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at 2.
[472] *Id.* at 4.

reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[473]

Irrespective of the company's concerns with applicability of SCR to the lean burn engines, ETC Texas Pipeline did conduct a cost effectiveness evaluation for SCR at Units 4A and 5A assuming a target NOx emission rate of 1 g/hp-hr.[474] Specifically, the company estimated the cost effectiveness of SCR at Unit 4A, which in its base emissions only operated 560 hours per year, as $28,561/ton, and at Unit 5A, which operated 4290 hours in its base emissions, at $7,517/ton.[475]

ETC Texas Pipeline appears to have used a 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines to estimate capital costs for SCR.[476] Specifically, the NESCAUM formula which was based on only one case study for a RICE unit to "approximate" SCR capita costs for lean burn RICE is as follows:

$310,000 + ($72.7 x hp)[477]

This NESCAUM equation is twenty years old and is likely based on cost data from the 1990's. SCR has been implemented on numerous source types over the past twenty years, and the much wider-scale implementation and innovation in catalyst design has lowered the cost of SCR.[478] Yet, ETC Texas Pipeline's analysis escalated the capital costs developed with the above equation from the 2000 NESCAUM report by assuming the NESCAUM cost equation was based on 1994 costs and escalating to 2019, using the differences in the Consumer Price Index between 1994 and 2019.[479] EPA's Control Cost Manual cautions against escalating costs more than five years due to the potential for significant inaccuracies in price estimates.[480]
EPA currently has a spreadsheet available to estimate the capital and operating costs for SCR. While the spreadsheet was developed for fossil fueled fired boilers, it can be used as an estimate for SCR at other natural gas-fired sources and, in fact, has been used oil and gas companies for several four-factor analyses submitted to NMED. Unfortunately, ETC Texas Pipeline did not include the necessary information to use the EPA SCR cost spreadsheet to estimate SCR costs for the Units 4A and 5A engines. NMED should ask the company to use the EPA spreadsheet rather than the NESCAUM formula and escalate the cost 25 years to current dollars.

[473] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[474] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at 2.
[475] *Id.* at Appendix B.
[476] *Id.* at 8. *See also* December 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines at III-30.
[477] *Id*.
[478] See EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.
[479] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at Appendix B.
[480] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.

In addition, the company's assumed annual operations and maintenance cost, estimated to be 20% of the total capital cost, is arbitrary and unjustified. In particular, ETC Texas Pipeline's annual operations and maintenance costs have no connection to the operating capacity of Units 4A and 5A. As a comparison, in Section XIX.A.2. below, we provide an SCR cost estimate using the EPA cost spreadsheet for the Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[481] For the two units at Roswell Compressor No. 9, that are 4500 hp each and that operate at 11% to 41% of available hours, the operation and maintenance costs to achieve 90% NOx reduction were roughly $26,000/year. See Table 46 in Section XIX.A.2. below.

If we assume that the operation and maintenance expense at Units 4A and 5A are the same as the larger units at Roswell Compressor No. 9 – i.e., $26,000 per year rather than ETC Texas Pipeline's assumed $134,973 per year, the cost effectiveness of SCR at Units 4A and 5A at Jal No. 3 decrease to $10,191/ton at Unit 4 A and $2,459/ton at Unit 5A. Thus, a more appropriate annual operations and maintenance cost make SCR very cost effective particularly at Unit 5A which operates more than Unit 4A.

For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal. NMED should request that ETC Texas Pipeline submit a refined analysis of SCR cost effectiveness using the EPA SCR cost spreadsheet.

B. SO2 Emissions from Thermal Oxidizer

ETC Texas Pipeline also evaluated controls for thermal oxidizer which combust the acid gas stream from its amine units.[482] We address that analysis in Section XXIII of this report.

XII. Davis Gas Processing Denton Gas Plant

The Denton Gas Plant is a natural gas processing plant in which the H2S is removed from the natural gas in an amine unit and then the gas is processed through a cryogenic unit to condense natural gas liquids.[483] The plant is located about 11 miles east of Lovington, New Mexico in Lea County. It is owned/operated by Davis Gas Processing. The plant consists of an amine unit, dehydrator regenerator, four-stroke rich burn RICE units, heaters, and tanks, but SO2 emissions from flaring of acid gases are the primary source of air emissions from the plant.[484] Thus, the four-factor analysis for this facility focused on the amine unit and the acid gas flare (Unit No. 007)Amine unit and flare.[485] Comments on the company's four-factor analysis are provided in Section XXIII further below, in comments on amine units and flaring emissions.

[481] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 5.
[482] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at 7.
[483] 5/10/2017 Title V Operating Permit No. P079-R3 for Davis Gas Processing Denton Gas Plant at 4.
[484] *Id.* at A6 to A8.
[485] November 2019 Four-Factor Analysis for Denton Gas Plant at 2-1.

XIII. El Paso Natural Gas Company – Washington Ranch Storage Facility

The El Paso Natural Gas Company, LLC. (EPNG) Washington Ranch Storage Facility is located in Eddy County and was identified by NMED as one of the sources contributing to regional haze at Carlsbad Caverns National Park Class I area.[486] NMED has described the facility processes as follows:

> The function of the facility is to compress and inject pipeline quality natural gas into underground storage wells and withdraw the gas for delivery into the pipeline.[487]

According to the permit, the plant includes two 2-stroke lean-burn reciprocating internal combustion engines (RICE), a 4-stroke rich-burn auxiliary engine, a glycol dehydrator and reboiler, a heater, a flare, and a diesel water pump engine.[488] In EPNG's four-factor submittal, the company evaluated air pollution controls for the following emission units:

- Cooper-Bessemer 2SLB RICE 12Q155HC2: Units A-01 and B-02.[489]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[490] The following provides a review of the company's four-factor analyses.

A. Units A-01 and B-02: Cooper-Bessemer 12Q155HC2 2-Stroke Lean-Burn Compressor Engines

Units A-01 and B-02 are 2-stroke lean-burn RICE that were constructed in 1982, each with a capacity of 4,500 hp.[491] The units each have an hourly NOx limit of 27.3 lb/hr and an annual NOx limit of 119.5 tpy.[492]

[486] November 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Washington Ranch Storage Facility at 3.
[487] Title V Operating Permit P064-R3 for Washington Ranch Storage Facility at 3.
[488] *Id.* at 5-6.
[489] November 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Washington Ranch Storage Facility at 4.
[490] *Id.* at 4.
[491] Title V Operating Permit P064-R3 for Washington Ranch Storage Facility at 5.
[492] *Id.* at 6.

1. Use of Low Emission Combustion Technology

EPNG describes a "layered approach" strategy for Clean Burn technology applied to the two engines reviewed in its four-factor analysis, A-01 and B-02.[493] Specifically, EPNG states that these units are already equipped with a turbocharger, advanced ignition system, pre-combustion chambers, high pressure fuel injection systems, and an Automatic Balancing Platform.[494] According to EPNG these Clean Burn technologies, based on manufacturer guidance, result in NOx emission rates of 0.5–2.75 g/hp-hr, or 27–82% reduction in NOx emissions.[495] Based on the information provided on the different Clean Burn technologies available for these engines it's possible that there are additional technologies that could be employed to ensure the NOx emission rates are closer to 0.5 g/hp-hr. For example, it's not clear if the pre-combustion chamber installed on units A-01 and B-02 is a "closed loop ePCC," which corresponds to emission rates of 0.5 g/hp-hr.[496] And it's also not clear if the Automatic Balancing Platform is considered "Advanced TER Control" or "Transient Control," the latter of which would result in emission rates around 0.5 g/hp-hr.[497] In EPA's Alternative Control Techniques document for RICE it reports achievable emission levels for retrofit low-emission designs for a Cooper-Bessemer 16Q155HC engine of 1.8 g/hp-hr.[498] And more recently, EPA has described layered combustion as demonstrated control techniques for 2-stroke lean-burn engines, achieving a NOx emission rate of 0.5 g/hp-hr.[499]

Units A-01 and B-02 have an allowable NOx emission rate of 27.3 lb/hr, or 2.75 g/hp-hr for these 4,500 hp units. And the source's Title V Permit Renewal Application specifies that these permit limits are based on the design for the low emission conversion.[500] NMED should require additional LEC retrofit techniques be evaluated in order to assess the cost effectiveness of further reducing NOx emissions from these engines to a level closer to 0.5 g/hp-hr. Reducing emissions to this level would achieve an additional 82% reduction in NOx emissions from these compressor engines. If these engines operate frequently it could be cost effective to update the Clean Burn technology on these engines, resulting in potentially significant NOx emissions

[493] November 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Washington Ranch Storage Facility at 8.
[494] *Id.*
[495] *Id.*
[496] *Id.* Note, Hoerbiger's Layered Approach Strategy for Clean Burn Technologies (Figure 3) illustrates varying prechamber (PCC) technologies, including "ePCC" and "closed loop ePCC." Hoerbinger's website describes this technology as Electronic Pre-Chamber Check (ePCC) Valves, *see* https://www.hoerbiger.com/en-3/pages/102
[497] *Id.*
[498] EPA 1993 Alternative Control Techniques Document for RICE at 5-68.
[499] 2016 EPA Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS (Docket ID No. EPA-HQ-OAR-2015-0500), Appendix A at 5-5, *available at:* https://19january2017snapshot.epa.gov/sites/production/files/2015-11/documents/assessment_of_non-egu_nox_emission_controls_and_appendices_a_b.pdf [hereinafter referred to as "CSAPR TSD for Non-EGU NOx Emissions Controls"].
[500] September 2013 Title V Permit Renewal Application El Paso Natural Gas Company, LLC Washington Ranch Storage Facility Section 6, Page 2.

reductions. At continuous operation these units have the potential to emit 120 tons per year of NOx each; an 82% reduction using layered combustion to meet a 0.5 g/hp-hr NOx emission rate would prevent almost 200 tons per year of NOx emissions from both units, when operating continuously.

2. Use of SCR

EPNG did not evaluate SCR for Units A-01 and B-02 primarily because it claimed that it was not technically feasible for variable load engines of this type.[501] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly because EPNG has not found LEC to be a cost effective NOx reduction strategy for these units.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[502]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[503] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[504] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

[501] November 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Washington Ranch Storage Facility at 7.
[502] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[503] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[504] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

XIV. Enterprise Blanco Compressor C & D

The Blanco C & D Compressor Station is a natural gas compressor station located about one mile northeast of Bloomfield, New Mexico in San Juan County.[505] It is owned/operated by Enterprise Field Services LLC.

The Title V operating permit for the facility indicates that the plant includes several natural gas-fired turbines, flares, and tanks.[506] In Enterprise's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- GE 5221W combustion turbines (Units T-C01 and T-C02)
- GE M5322B combustion turbine (Unit T-D01)[507]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[508] The following provides a review of the company's four-factor analyses. The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

Enterprise used an 8.38% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[509] This is an unreasonably high interest rate for cost effectiveness analyses. EPA's Control Cost Manual indicates that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[510] The current bank prime rate is 3.25%.[511] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[512] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. However, in a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[513] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate

[505] Title V Operating Permit P218-R2M1 for Blanco C&D Compressor Station at 3.
[506] *Id.* at 7.
[507] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at 1-2.
[508] *Id.*
[509] *Id.* at Section 8.0 Supporting Documentation.
[510] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[511] https://www.federalreserve.gov/releases/h15/.
[512] https://fred.stlouisfed.org/series/DPRIME.
[513] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

(and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. Enterprise's use of an 8.38% interest rate is unreasonably high and overstates the cost effectiveness of pollution controls evaluated in the four-factor analyses.

B. GE Combustion Turbines: Units T-C01 and T-C02 and T-D01

Units T-C01 and T-C02 at the Blanco C&D Compressor Station are each 22,280 hp natural gas-fired turbines that are listed in the Title V permit as constructed before June 1989.[514] The units each have a NOx emissions limit of 80.0 lb/hr and 350.4 tpy.[515] For these units, Enterprise identified water or steam injection as viable combustion controls for NOx but claimed that dry low NOx combustors were not available for retrofit to these types of gas turbines.[516] Unit T-D01 is a GE M5322B combustion turbine of 32,550 hp capacity that is identified in the Title V permit as being constructed before October 1987.[517] Unit T-D01 has NOx limits of 143.3 lb/hr and 628 tpy.[518] For this unit, Enterprise identified water or steam injection or dry low NOx combustors as feasible controls.[519] Enterprise claimed that SCR installation was not possible for any of these gas turbines, due to the size estimates of the SCR.[520] Presumably, Enterprise is claiming issues of retrofit difficulty. There is no question that SCR is technically feasible for natural gas-fired combustion turbines, including those used at compressor stations.

1. Evaluation of Baseline NOx Emissions.

According to the company's cost analysis for water/steam injection, Unit T-C01 has an actual NOx emission rate of 36.92 lb/hr (57.7 ppm), Unit T-C02 has an actual NOx emission rate of 51.56 lb/hr (83.2 ppm), and Unit T-D01 has an actual NOx emission rate of 49.32 lb/hr (65.0 ppm) based on 2016 stack test data.[521] These actual emission rates are much lower than the units' allowable NOx emission rates so, either the 2016 stack test data was not performed while the engines were operating at maximum capacity or the allowable NOx emission rates have been set unreasonably high. In addition, while both Units T-C01 and T-C02 are the same model and same horsepower, one unit's NOx rate (T-C01) is listed by Enterprise as 31% lower than the NOx rate of T-C02. That does not make sense, if such emission rates are reflective of test data at maximum or close to maximum capacity. NMED should present information on the 2016 stack test data so the circumstances of the stack tests can be reviewed. In addition, NMED and Enterprise should review other stack tests for these units to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. If testing is only done sporadically, such as once every five years, then it is

[514] Title V Operating Permit P218-R2M1 for Blanco C&D Compressor Station at 7.
[515] *Id.* at 8.
[516] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at 2-2 to 2-4.
[517] Title V Operating Permit P218-R2M1 for Blanco C&D Compressor Station at 7.
[518] *Id.* at 8.
[519] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at 2-2 to 2-4.
[520] *Id.* at 2-4.
[521] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at Section 8.0.

questionable that such stack test data truly reflect an accurate projection of emissions expected over the lifetime of the controls being evaluated, especially given that the emission rates are so much lower than the units' allowable pound per hour emission rates. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on an estimate of emissions expected in 2028.

2. Evaluation of Water Injection and Steam Injection for NOx Control

Enterprise only assumed 15% NOx reduction from water or steam injection.[522] While Enterprise cites to EPA's AP-42 emission factor documentation for the 15% control with water or steam injection, EPA's AP-42 states that such controls can achieve 60% or higher NOx removal.[523] EPA's 1993 Alternative Control Techniques Document for NOx emissions from Stationary Gas Turbines, which EPA's AP-42 documentation cites to, states that NOx rates in the range of 25 to 42 ppmv can be achieved with water or steam injection as gas-fired combustion turbines.[524] If the uncontrolled emissions of Units T-C01, T-C02, and T-D01 are truly in the range of 57.7 to 83.2 ppm as indicated in Enterprise's four-Factor analyses (assuming this is parts per million by volume at 15% oxygen, which NMED should confirm), water injection to meet a NOx rate of 25-42 ppm reflects 27% to 70% NOx removal. NMED must require that Enterprise evaluate water or steam injection for these units reflective of the NOx rates that have historically been achieved with water or steam injection.

With respect to the life assumed of water or steam injection, Enterprise only assumed a 15-year life of these controls.[525] Enterprise did not provide any justification for assuming such a short life of water or steam injection. As discussed in NPCA's March 2020 report, the life of water or steam injection should be the life of the combustion turbines. In NPCA's March 2020 report, we assumed a 25-year life of water or steam injection.[526]

In terms of Enterprise's costs for water injection or steam injection, the company's capital costs seem very high for the size turbines, based on a comparison to the 1999 Department of Energy report entitled "Cost Analyses of NOx Control Alternatives for Stationary Gas Turbines," which is cited in several EPA and State documents on the costs of NOx controls at gas turbines.[527] In that 1999 DOE report, the costs of water or steam injection for a gas turbine that is larger than Units T-C01 and T-C02 and slightly smaller than T-D01, a GE LM2500 turbine which is of 22.7 megawatt capacity or about 30,400 hp, the capital cost in 1999 dollars of water injection was

[522] *Id.*
[523] EPA, AP-42 Emission Factor Documentation, at 3.1-6.
[524] *See* EPA. Alternative Control Techniques Document – NOx Emissions form Stationary Gas Turbines, EPA-453/R-93-007, January 1993, at 2-5 [hereinafter EPA 1993 Gas Turbine ACT].
[525] November 2019 Regional Haze Four-Factor Analysis for Blanco C&D Compressor Station at 6-1.
[526] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 64.
[527] Bill Major, ONSITE SYCOM Energy Corporation, and Bill Powers, Powers Engineering, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, prepared for U.S. Department of Energy, November 5, 1999, available at: https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf [hereinafter "1999 DOE Report"].

estimated to be $1,083,175.[528] Although EPA's Control Cost Manual advises against escalating costs more than five years because it can lead to inaccuracies in price estimation,[529] just using the Chemical Engineering Plant Cost Indices between 1999 and 2018, the DOE's 1999 costs of water injection for a larger GE LM2500 gas turbine would increase to $1.67 million.[530] Using a different cost index specific to oil refineries, the Nelson-Farrar index, the 1999 costs of water injection increase from $1.0 million to $1.88 million as of 2016 (the most recent annual Nelson-Farrer cost index found online).[531] Yet, Enterprise's capital cost estimate for water injection at T-C01 and T-C02 was $6.1 million, more than three times the escalated capital costs from the 1999 DOE report based on either the CEPCI index or the Nelson-Farrar index. Thus, Enterprise's capital cost estimate of water injection for a smaller capacity gas turbine at these units seem very high, and its capital costs for steam injection are $2 million higher than its costs for water injection. Further, the inspection and operating costs of water injection, which Enterprise stated would be $1,238,327 per year,[532] are not explained or documented and seem unreasonably high. NMED must request more details and support for these cost estimates of water injection and of steam injection at these units.

We addressed just some of these issues to revise Enterprise's cost effectiveness analyses to reflect 1) a 4.7% interest rate (instead of 8.38%), 2) a 25-year life of water or steam injection (instead of an assumed 15-year life), 3) a controlled NOx rate with water or steam injection of 25 ppmvd at 15% O_2. With the revisions listed in items 1 through 3 above, Enterprise's cost effectiveness of water or steam injection reduced from approximately $57,000 to $110,000/ton of NOx removed to $14,000 to $51,000/ton, and it is important to note that no changes were made to Enterprise's apparently inflated capital and operating costs of water or steam injection.

In its identification of energy and non-air quality environmental impacts of compliance, Enterprise did not list water use as an adverse environmental impact, but it is an issue to be concerned with for water injection.[533] That is why dry low NOx combustion, if available (which Enterprise claims is not available for the Units T-C01 and T-C02 turbine models) or selective catalytic reduction (SCR) are more preferable choices for NOx control from gas-fired turbines in New Mexico.

3. Evaluation of Dry Low NOx Combustion at Unit T-D01

Enterprise did evaluate dry low NOx combustors for the GE M5322B unit (Unit T-D01), but claimed that dry low NOx combustors could only achieve a NOx rate of 35 ppmv at this unit, or

[528] *Id.*, Appendix A at A-4.
[529] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.
[530] Based on multiplying the 1999 cost estimate for water injection from the 1999 DOE report by the ratio of the CEPCI indices for 2018 to 1999 (603.1/390.6).
[531] Based on multiplying the 1999 cost estimate for water injection from the 1999 DOE report by the ratio of Nelson-Farrar indices for 2016 to 1999 (2598.7/1497.2).
[532] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 8-2 to 8-3.
[533] *See* March 6, 2020 NPCA Oil and Gas Four-Factor Report at 67-68.

a NOx reduction efficiency of 46%. This is a high NOx rate and a low NOx removal efficiency to assume with dry low NOx combustors. As discussed in NPCA's March 2020 Oil and Gas Four-Factor Report, such controls can achieve NOx removal efficiencies of 80-95% with typical NOx emission rates in the range of 9-15 ppm.[534] In a 1999 Department of Energy Report on the costs of NOx controls for gas combustion turbines, the highest NOx emission rate evaluated with dry low NOx combustors was 25 ppm.[535] Thus, Enterprise's cost effectiveness analysis for dry low NOx combustors assumed an unreasonable low level of NOx reduction with this control.

In terms of the life of dry low NOx combustion controls in the cost effectiveness analyses, Enterprise's analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[536]

In the table below, Enterprise's cost effectiveness analyses of dry low NOx combustors were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate. In addition, two lower NOx rates were evaluated: 25 ppm and 15 ppm.

Table 32. Revised Cost Effectiveness of Dry Low NOx Combustors at Unit T-D01 of the Blanco C&D Compressor Station, to Reflect a 4.7% Interest Rate and a 25 Year Life[537]

NOx Emission Rate Evaluated, ppm	NOx Removal Efficiency Evaluated	Annual Cost of Dry Low NOx Combustors (at 4.7% interest and 25 Year Life)	NOx Emissions Reduced, tpy	Cost Effectiveness
35[538]	46%	$609,798	91.04	$6,694/ton
25	62%	$609,798	121.46	$5,021/ton
15	77%	$609,798	151.82	$4,017/ton

Dry low NOx combustors at Unit T-D01 are much more cost effective than water or steam injection and, based on historical assumed NOx emission rates with these controls which range between 15 to 25 ppm (or even as low as 9 ppm), such controls should be able to reduce NOx emissions at Unit T-D01 by 62 to 77% or maybe more.

[534] March 2020 NPCA Oil and Gas Four-Factor Report at 69.
[535] *Id.* *See also* Bill Major, ONSITE SYCOM Energy Corporation, and Bill Powers, Powers Engineering, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, prepared for U.S. Department of Energy, November 5, 1999, 2-10, available at: https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf.
[536] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.
[537] The company's capital and operational and maintenance costs were not revised for this analysis. Only the interest rate was reduced from 8.38% to 4.7% and the life of controls was revised from 20 to 25 years.
[538] This in the NOx rate evaluated by Enterprise for dry low NOx combustors at Unit T-D01.

4. Evaluation of SCR for the Gas Turbines at Blanco C&D Compressor Station

Enterprise did not evaluate SCR for the gas turbines at the Blanco C&D Compressor Station, stating that it was "not possible to install these units at the Blanco facility" due to "the amount of buffer space needed to maintain accessibility to equipment and to avoid compromising worker safety."[539] While the facility and gas turbines may not have been originally designed to have space to accommodate SCR, that is typically the case with most SCR retrofits. As such, there have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints. For example, for many large coal-fired power plants, SCR reactors have been elevated above the air preheaters. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new foundations to make way for the SCR reactor.[540] Thus, before NMED accepts a very brief claim of retrofit difficulty of SCR at any emissions unit being evaluated for reasonable progress controls, it is imperative that NMED ask Enterprise for a site plan and photos that shows whatever space constraints are being claimed. Moreover, NMED must ask Enterprise to consult with SCR vendors for options for SCR installation at the gas turbines of the Blanco C&D Compressor Station.

If any of the combustion turbines are in close proximity to another turbine, that provides opportunities for a shared SCR reactor which could help with retrofit space issues as well as with costs. NMED must require all possibilities for SCR installation be evaluated and documented by Enterprise. The state must not simply discount this highly effective NOx control based on a claim of some retrofit difficulty.

In terms of the costs of SCR control, NPCA's March 2020 Oil and Gas Four-Factor Report showed the cost effectiveness in 1999 dollars for SCR achieving about 90% NOx reductions would range from $2000/ton to $3400/ton for a 5 MW combustion turbine (~6800 hp engine) depending on the operating capacity factor, and costs decrease for larger turbines like Units 17 and 19 which are approximately 19500 hp engines.[541] For much larger combustion turbines of 75 MW generating capacity (~100,500 hp), cost effectiveness of SCR was significantly lower in the range of $560-$850/ton depending on operating capacity factor.[542]

To get an idea of the costs for SCR at Units T-C01, T-C02, and T-D01 in current dollars, one can use EPA's SCR cost spreadsheet made available as part of EPA's Control Cost Manual. It is difficult to estimate an actual cost effectiveness because it is not clear what the 2016 actual annual fuel throughput was at each unit, which is necessary for estimating annual operations and maintenance costs for SCR. However, a 2017 Title V Permit Application for Blanco C & D

[539] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at 2-4.
[540] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, , available at https://www.onepetro.org/conference-paper/SPE-66501-MS.
[541] *See* NPCA March 2020 Oil and Gas Four-Factor Report at 75.
[542] *Id.*

compressor stations does have information to enable an estimate of the capital cost of SCR. A review of the EPA SCR cost spreadsheet shows that the capital cost of SCR is based primarily on two factors: maximum hourly heat input to the unit in MMBtu/hr and the site elevation.[543] A 2017 Title V Permit Application for Blanco C&D compressor stations has the maximum hourly heat input to each unit as well as other data, although some of the other data is not legible in the copy of the document on NMED's Emissions Analysis Tool website.[544] Specifically, the hourly heat input to Units T-C01 and T-C02 is identified as 283 MMBtu/hr and the hourly heat input to Unit T-D01 appears to be 311.18 MMBtu/hr.[545]
The site elevation is listed as 5605 feet.[546]

Enterprise's claimed baseline NOx emission rates of 57.2 ppm, 87.3ppm, and 65.0 ppm for Units T-C01, T-C02, and T-C03 were utilized and assumed to be reflective of ppm by dry volume at 15% oxygen. As previously discussed, NMED should ensure that this 2016 test data reflects operations at maximum operating capacity and ensure that these emission rates are a reasonable projection of NOx emissions as of 2028. The company's actual NOx rates were converted to lb/MMBtu emission rates using a conversion formula from EPA's 1993 Alternative Control Techniques Document for Stationary Gas Turbines.[547] Enterprise's ppm NOx baseline rates thus were converted to 0.231 lb/MMBtu for Unit T-C01, 0.334 lb/MMBtu for Unit T-C02, and 0.341 lb/MMBtu for Unit T-D01. With this data, unit-specific information was input into EPA's SCR cost spreadsheet to estimate cost effectiveness of SCR at these units. For Units T-C01 and T-C01, the average exhaust gas temperature of the bypass stacks of 625 degrees Fahrenheit was used and for Unit T-D01 the exhaust gas temperature of 904 degrees Fahrenheit was used.[548] Two different SCR control levels were assumed: a 15 ppmvd NOx rate, which reflects 74% to 82% NOx removal at the Blanco C&D combustion turbines, and a 90% control efficiency from current uncontrolled actual NOx rates at each turbine. With Enterprise's 2016 actual annual NOx emissions and its reported ppm NOx emissions and the reported heat value of the fuel, actual annual gas consumption rates were estimated for each unit for input into the SCR cost spreadsheet. Capital costs were annualized applying a cost recovery factor using a 4.7% interest rate, and a 25-year life which EPA has identified as typical for SCR systems used at industrial boilers.[549] One reagent type was evaluated: 29% aqueous ammonia. The results of these analyses are provided in the table below.

[543] *See* equations in "Cost Estimate" tab, cell B19 (Total Capital Investment), which in turn points to cells G19 and H19, which in turn are based on "Data Inputs" tab cells C10 and C24.
[544] June 27, 2017 Application for Significant Modification, Title V Operating Permit P218-R2, Enterprise Field Services LLC – Blanco C&D Compressor Station, at pdf pages 34-35.
[545] *Id.*
[546] *Id.* at 35. Note the site elevation for Units T C-01 and T-C01 is not legible, but it is assumed that each C and D compressor station are at the same elevation.
[547] *See* EPA, Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993, Appendix A which has conversion equations for natural gas-fired combustion turbines.
[548] *Id.* at pdf page 34-35.
[549] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

Table 33. Cost Effectiveness of SCR at Blanco C&D Compressor Stations Units T-C01, T-C02, and T-D01 Combustion Turbines, Using EPA's SCR Cost Calculation Spreadsheet for Boilers (2018 $)

Unit	Assumed NOx Removal Efficiency with SCR	Capital Cost SCR	Annual Operational and Maintenance Cost	Total Annualized Costs	NOx Reduced, tpy	Cost Effectiveness
T-C01	74.0%	$7,536,749	$155,039	$676,647	119	$5,693
T-C01	90.0%	$7,536,749	$161,977	$683,585	144	$4,731
T-C02	82.0%	$7,536,749	$160,398	$682,006	180	$3,787
T-C02	90.0%	$7,536,749	$164,425	$686,034	198	$3,472
T-D01	77.0%	$8,016,420	$159,735	$714,374	153	$4,684
T-D01	90.0%	$8,016,420	$166,270	$720,909	178	$4,044

The cost estimates of SCR based on EPA's boiler SCR cost spreadsheet project costs for SCR that are significantly lower than the other NOx control evaluated by Enterprise – water or steam injection or dry low NOx combustion for Unit T-D01, for which capital costs were projected to range from $6.6 to $8.2 million.[550] Given that SCR can achieve much higher levels of control at much lower costs than water or steam injection, NMED must require Enterprise to more fully evaluate the ability to install SCR at Unit 17 and/or 18 . Ninety percent control should be readily achievable with SCR at these units to meet a NOx emission rate of 5 to 8 ppmv (0.0231 to 0.0334 lb/MMBtu). Before allowing Enterprise to dismiss SCR due to claims that it is not feasible to locate one or more SCR reactors at Units T-C01, T-C02, and T-D01, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at the units, including any options for shared SCR reactors between Units T-C01 and T-C02. SCR can be a very effective method for reducing NOx emissions from the Blanco C & D compressor station gas turbines and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for the Blanco C & D Compressor Station.

XV. Harvest Pipeline – San Juan Gas Plant

The Harvest Pipeline Company San Juan Basin Gas Plant is a facility that extracts and processes natural gas liquids and residue gas products from field gas via a cryogenic process. It is located about 2 miles northeast of Bloomfield, New Mexico. The facility consists of several combustion turbines, a diesel generator, heaters, a thermal oxidizer, and a flare.[551] It is located adjacent to the Blanco Compressor Stations of EPNG (Blanco C&D) and El Paso Field Services (Blanco A).[552]

[550] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at 8-1 to 8-3.
[551] *Id.* at A6.
[552] Title V Permit No. P124-R3 for San Juan Basin Gas Plant, at A3.

In fact, the three Blanco Compressor Stations and the San Juan Gas Plant are all considered one source under the New Source Review program by NMED.[553]

In Harvest Pipeline's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Rolls Royce 155 Natural Gas Turbines (Units 1-4)
- Solar Centaur T4501 Natural Gas Turbines (Units 4-7).[554]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[555] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

Harvest Pipeline used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[556] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[557] The current bank prime rate is 3.25%.[558] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[559] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[560] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

[553] 10/10/2018 Statement of Basis for San Juan Gas Plant, Permit Nos. 0613-M8 and P124-R3 at 2.
[554] November 2019 Regional Haze Four-Factor Analysis for Harvest San Juan Gas Plant at 1-2.
[555] *Id.*
[556] *Id.* at Appendix B Cost Analysis Calculations.
[557] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[558] https://www.federalreserve.gov/releases/h15/.
[559] https://fred.stlouisfed.org/series/DPRIME.
[560] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

B. Rolls-Royce 155 Combustion Turbines: Units 1-4 at San Juan Gas Plant

Units 1-3 of the San Juan Gas Plant are Rolls-Royce Natural Gas Turbines that were manufactured in the mid-1980's.[561] The turbines have a permitted capacity of 15000 hp each, although they have a manufacture rated capacity of 23,800 hp.[562] Unit 4 is a rotating spare for Units 1 – 3, which operates only when Units 1, 2, or 3 are down for repair.[563] The turbines have catalytic oxidation for carbon monoxide and volatile organic compound (VOC) control.[564] The units are each subject to a NOx limit of 56.3 lb/hr and 246.4 tpy.[565] The units are also subject to a NOx limit of 150 ppmv at 15% O_2 pursuant to 40 C.F.R. Part 60, Subpart GG.[566]

For these units, Harvest Pipeline did not evaluate any additional NOx pollution controls. The company stated that it contacted Siemens, the company that currently owns the Rolls-Royce Avon gas turbine and compressor business, and that Siemens stated that neither dry low NOx combustion nor water or steam injection was an available control option for retrofit to the mid-1980's era Rolls-Royce turbines at the San Juan Gas Plant.[567] Siemens indicated that SCR is available for the turbine model, yet Harvest Pipeline did not evaluate SCR. The following provides comments on SCR applicability for the Rolls-Royce turbines.

1. Evaluation of SCR at the Rolls-Royce Turbines (Units 1-4)

Although, according to the four-factor analysis for the San Juan Gas Plant, Siemens claimed that SCR was an available technology for the Rolls-Royce turbines, Harvest Pipeline did not evaluate SCR technology for the turbines. The company claimed that the high exhaust temperature of the turbines (1250 degrees Fahrenheit according to the four-factor analysis) and concerns about space and power usage made SCR not feasible for the Rolls-Royce turbines.[568] SCR should not have been so readily discounted as a pollution control for the Rolls-Royce turbines. With respect to space limitations, as discussed in Section I.B.3. above, most SCR retrofits have space limitations, because the facility was not likely designed to have space to accommodate SCR. There have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints. For example, for many large coal-fired power plants, SCR reactors have been elevated above the air preheaters. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new

[561] Title V Permit No. P124-R3 for San Juan Basin Gas Plant, at A6.
[562] *Id.*
[563] November 2019 Regional Haze Four-Factor Analysis for Harvest San Juan Gas Plant at 1-3.
[564] *Id.* at A7.
[565] *Id.*
[566] *Id.* at A8.
[567] *Id.* at 2-3 to 2-4.
[568] *Id.* at 2-5 to 2-6.

foundations to make way for the SCR reactor.[569] Thus, before NMED accepts a very brief claim of retrofit difficulty of SCR at any emissions unit being evaluated for reasonable progress controls, it is imperative that NMED ask Harvest Pipeline for a site plan and photos that shows whatever space constraints are being claimed, and that NMED ask the company to consult with SCR vendors for options for SCR installation at the gas turbines.

Depending on the proximity of the gas turbines, it is possible that one SCR reactor could be used by more than one combustion turbine. This would reduce costs and potentially be easier to install at the site. NMED should require all possibilities for SCR installation be evaluated and documented by Enterprise. The state must not simply discount this highly effective NOx control based on a claim of some retrofit difficulty.

Regarding the company's stated exhaust temperature of 1,271 degrees Fahrenheit, NMED should determine if this is the sustained temperature of the gas turbines or the maximum temperature of the exhaust expected from the turbines. It must be noted that this exhaust temperature of 1,271 degrees Fahrenheit claimed in the four-factor analysis is much higher than the exhaust temperatures of the units cited in the February 2017 Title V permit application for the San Juan Gas Plant. Specifically, the 2017 permit application listed the exhaust temperature of Units 2 and 3 of 370 degrees Fahrenheit and the Unit 1, Unit 2 bypass, and Unit 3 bypass exhaust temperature as 750 degrees Fahrenheit.[570] Thus, NMED must ensure the accuracy of any stated claims about SCR being infeasible due to exhaust gas temperatures before allowing SCR to be eliminated as a control option. In addition, there are options for dealing with high exhaust temperature of simple cycle turbines to enable the use of SCR. The Buckingham Compressor Station which is proposed to be constructed in Virginia would be equipped with Solar turbines with SoLoNOx, SCR, and cooling air skids.[571] Essentially, the cooling air skids provide for the injection of tempering air at the turbine discharge (upstream of the SCR) to cool the exhaust temperature to the optimal temperature of the SCR catalyst.[572]

Further, if the Rolls-Royce turbines truly have exhaust temperatures of 1,271 degrees Fahrenheit, that is another reason why NMED should investigate routing more than one combustion turbine exhaust to a common SCR. The routing of turbine exhausts from multiple turbines to one SCR reactor will allow for some cooling of the exhaust before it enters the SCR. As previously discussed, SRP is planning to route the flue gas from one boiler at the Coronado

[569] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, , available at https://www.onepetro.org/conference-paper/SPE-66501-MS.
[570] February 2017, New Mexico Application to Renew Permit P-124-R2, San Juan Gas Plant, Submitted by Conoco Phillips Company, at pdf page 39 (San Juan Basin Gas Plant, Turbine Exhaust Emissions Calculations).
[571] *See* May 25, 2018 Permit Application for Altlantic Coast Pipeline LLC, Buckingham Compressor Station, at pdf page 129 (Design Summary), which is available for download at https://www.deq.virginia.gov/Programs/Air/BuckinghamCompressorStationAirPermit/BuckinghamCompressorStationArchivedDocuments.aspx.
[572] *See,* e.g., Buzanowski, Mark A. and Sean P. McMenamin, Peerless Mfg. Co., Automated Exhaust Temperature Control for Simple Cycle Power Plants, available at https://www.powermag.com/automated-exhaust-temperature-control-for-simple-cycle-power-plants/. *See also* Mitsubishi Hitachi Power Systems (MHPS) webpage on SCR systems for simple cycle turbines at https://amer.mhps.com/scr-for-simple-cycle-gas-turbines.html.

Generating Station in Arizona to an existing SCR reactor that had previously been constructed at the coal-fired power plant Coronado Unit 2. Such an approach seems like it could be a viable, more cost effective, control option for co-located combustion turbines at compressor stations.

To estimate the cost effectiveness of SCR for the Rolls-Royce combustion turbines, EPA's SCR cost spreadsheet was used along with the turbine operational data presented in the company's February 2017 Title V Permit Application.[573] Because Harvest Pipeline did not evaluate any emissions controls for the Rolls-Royce units, there was no information in the four-factor analysis on actual emissions and/or actual operating hours for the units. Thus, this SCR cost effectiveness analysis had to be based on an allowable emissions baseline. The uncontrolled NOx rate for input into the spreadsheet was estimated by dividing the allowable hourly emission rate of 56.30 by the hourly fuel consumption of the turbines of 123.2 MMBtu/hr,[574] for an uncontrolled NOx rate of 0.457 lb/MMBtu. Consistent with other SCR analyses presented herein and in NPCA's March 2020 Oil and Gas Four-Factor Report, it was assumed that SCR could achieve a NOx emission rate of 15 ppmv at 15% O_2,[575] which converts to 0.06 lb/MMBtu. That NOx rate reflects an 87% reduction across the SCR system from the lb/MMBtu allowable NOx emission rate. To reflect a lower capacity factor than potential to emit, an analysis was also done assuming the unit operated at 70% of maximum annual fuel throughput. Consistent with all other SCR cost analyses provided herein, a 25-year life of SCR and a 4.7% interest rate was used. The results of this cost effectiveness analysis are provided in the table below.

Table 34. Cost Effectiveness of SCR to Achieve ~87% NOx Reduction (15 ppmv at 15% O_2) at Unit 1, 2, and 3 of the San Juan Gas Plant, Assuming a 25-Year Life of SCR and a 4.7% Interest Rate

Annual Capacity Factor	Capital Cost of SCR	Annual Operational and Maintenance Costs of SCR	Annualized Cost of SCR	NOx Emission Reductions, tpy	Cost Effectiveness of SCR
100%	$4,388,725	$98,826	$403,662	214	$1,884/ton
70%	$4,388,725	$79,310	$387,146	150	$2,562/ton

Harvest Pipeline also indicated that the electricity currently available at the San Juan facility is sufficient to power SCR systems at the Rolls-Royce units, and stated that "[i]nstallation of [SCR] will require the facility to expand its current power generation."[576] Based on electricity calculations of EPA's SCR cost spreadsheet, if SCR systems were operated for each unit and each unit was operated at 100% of maximum capacity, the electricity needs would be 71.91 kW per hour per unit for an hourly demand need of 0.216 MW. NMED should ask Harvest Pipeline

[573] February 2017, New Mexico Application to Renew Permit P-124-R2, San Juan Gas Plant, Submitted by Conoco Phillips Company, at pdf page 39 (San Juan Basin Gas Plant, Turbine Exhaust Emissions Calculations).
[574] *Id.*
[575] *See* March 2020 NPCA Oil and Gas Four-Factor Report at 75.
[576] November 2019 Regional Haze Four-Factor Analysis for Harvest San Juan Gas Plant at 2-6.

for more information on its current levels of power generation and/or power supply and to estimate what would be necessary to increase the power generation at the site or to the site to accommodate SCR systems. If one SCR reactor could be shared between the three combustion turbines, that could not only reduce the cost of SCR and allow for a less complicated retrofit, but it could also reduce the energy needs of SCR.

Thus, NMED must not allow Harvest Pipeline to discount SCR for the Rolls-Royce units. It is a highly effective NOx control that the turbine manufacturer (Siemens) states is an available retrofit for the existing turbines. NMED must require a thorough evaluation of SCR to reduce NOx emissions from the Rolls-Royce turbines.

C. Solar Centaur T4501 Natural Gas Turbines (Units 4-7)

Units 4-7 of the San Juan Gas Plant are Solar Centaur turbines model T4501 with a permitted capacity of 3735 hp that were each manufactured in 1986.[577] The units each have NOx limits of 15.9 lb/hr and 69.8 tpy.[578] The units are also each subject to a NOx limit of 150 ppmv at 15% O_2 pursuant to 40 C.F.R. Part 60, Subpart GG.

Harvest Pipeline evaluated the following pollution controls for these units:

- SoLoNOx Combustion Technology
- SCR.

The following provides comments on Harvest Pipeline's analyses of these controls.

1. Evaluation of SoLoNOx for Units 4-7 at San Juan Gas Plant

Harvest Pipeline states that SoLoNOx is available for the existing Solar Centaur combustion turbines at Units 4-7, but it would require the units to be uprated to model Centaur T4701 to support the SoLoNOx technology.[579] Harvest Pipeline states that such controls could reduce NOx to 25 ppm, a reduction of 65-75% from 2016 hourly NOx rates.[580]
In terms of the life of SoLoNOx controls in the cost effectiveness analyses, Harvest Pipeline's analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[581] In the table below, Harvest Pipeline's cost effectiveness analyses of SoLoNOx were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate.

[577] Title V Permit No. P124-R3 for San Juan Basin Gas Plant, at A6.
[578] *Id.* at A7.
[579] November 2019 Regional Haze Four-Factor Analysis for Harvest San Juan Gas Plant at 2-3.
[580] *Id.*
[581] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

Table 35. Revised Cost Effectiveness of SoLoNOx at Units 4-7 of the Harvest Pipeline San Juan Gas Plant, to Reflect a 4.7% Interest Rate and a 25-Year Life

Unit	Harvest Pipeline's Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	Harvest Pipeline's Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25 Year Life
4	$69,637	$1,952/ton	$61,274	$1,717/ton
5	$69,637	$2,412/ton	$61,274	$2,122/ton
6	$69,637	$1,894/ton	$61,274	$1,667/ton
7	$69,637	$1,500/ton	$61,274	$1,319/ton

Thus, the cost effectiveness of SoLoNOx at the Units 4-7 Solar Centaur Combustion Turbines should be in the range of $1,319/ton to $2,122/ton assuming a more appropriate 25-year life at lower interest rate. These controls should be considered quite cost effective by NMED.

2. Evaluation of SCR for Units 4-7 of the San Juan Gas Plant.

Harvest Pipeline evaluated SCR as a technically feasible control option for the Units 4-7 Solar Centaur gas combustion turbines, using EPA's SCR cost spreadsheet made available with EPA's Control Cost Manual.[582] However, Harvest Pipeline only assumed a 25 ppm NOx rate could be met with SCR, which only reflects 65% to 76% NOx reduction efficiency with SCRAs presented NPCA's Oil and Gas Four-Factor Report, NESCAUM assumed 90% control with SCR in its 2000 Status Report to control small gas turbines down to 15 ppmv.[583] SCR at the San Juan Gas Plant Units 4-7 should be able to at least achieve a 15 ppmv NOx limit, which reflects 79% to 85% control at each unit.

Harvest Pipeline presented cost effectiveness data for SCR at Units 4-7, but the costs appear to be significantly inflated. The company assumed a $4,000,000 capital cost of SCR that it purportedly obtained from the manufacturer, which is Solar Turbines.[584] It is not clear that Solar Turbines is a vendor for SCR systems. The company also apparently used the EPA cost spreadsheet for the direct annual costs including operating and maintenance costs.[585] Yet, when the inputs used by Harvest Pipeline for each unit are independently input in the EPA SCR cost spreadsheet, the annual operation and maintenance costs are shown to be much lower than assumed by Harvest Pipeline, and the capital cost of SCR is shown to be much lower than $4,000,000 per unit. For example, when one enters into the EPA spreadsheet the same

[582] November 2019 Regional Haze Four-Factor Analysis for San Juan Gas Plant, Appendix C.
[583] NPCA March 2020 Oil and Gas Four-Factor Report at 74-75. *See also* NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15), available at http://www.nescaum.org/documents/nox-2000.pdf/view.
[584] November 2019 Regional Haze Four-Factor Analysis for San Juan Gas Plant at 3-2.
[585] *Id.*

information in the data input page for Unit 4 provided in the San Juan Gas Plant Four-Factor Report, the resulting calculation of operations and maintenance costs are $10,703 per year plus $2,718 in administrative charges for a total of $13,421 per year, whereas Harvest Pipeline assumed annual operating and mainatenance costs of $122,869 per year, costs that are nine times higher than calculated with EPA's cost spreadsheet. In addition, the EPA SCR cost spreadsheet calculates the capital cost of SCR at $1.5 million for the unit rather than Harvest Pipeline's claimed $4 million cost, a value that is 2.7 times what the EPA SCR cost spreadsheet calculated.

In the table below, we recalculated cost effectiveness of SCR at Units 4-7 of the San Juan Gas Plant. For this analysis, we used EPA's SCR cost spreadsheet with the same inputs as identified in Harvest Pipeline's Four Factor report.[586] However, for the controlled level of NOx, an emission rate of 15 ppmv was assumed to be met (reflective of 0.10 lb/MMBtu and NOx removal efficiencies in the range of 79% to 85%. For the reasons previously described in this report, an interest rate of 4.7% and a 25-year life of SCR were assumed. The table below presents the results of this analysis.

Table 36. Cost Effectiveness of SCR at San Juan Gas Plant Units 4, 5, 6 and 7 Combustion Turbines to Meet 15 ppmv NOx Rate, Using EPA's SCR Cost Calculation Spreadsheet for Boilers (2018 $)

Unit	Assumed NOx Removal Efficiency with SCR	Capital Cost SCR	Annual Operational and Maintenance Cost	Total Annualized Costs	NOx Reduced, tpy	Cost Effectiveness
4	82%	$1,501,589	$20,793	$126,820	41	$3,059/ton
5	79%	$1,495,807	$21,342	$126,972	44	$2,869/ton
6	82%	$1,465,046	$21,012	$124,523	44	$2,839/ton
7	85%	$1,475,477	$22,001	$126,230	52	$2,405/ton

The above table shows that SCR, based on EPA's cost algorithms, can be cost effective at Units 4, 5, 6 and of the San Juan Gas Plant.

Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[587] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for

[586] *Id.* in Appendix B, pdf pages 27, 31, 35, and 39 of the report.

[587] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.

such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[588] NMED should require Harvest Pipeline to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

XVI. Oxy USA WTP -Indian Basin Gas Plant

The Oxy USA WTP (Oxy) Indian Basin Gas Plant is a gas sweetening plan (removing hydrogen sulfide and CO_2 from raw natural gas to make commercial natural gas) and also extracts natural gas products (propane and butane) from natural gas.[589] The facility is located 15 miles west of Carlsbad, New Mexico in Eddy County.[590] The emission units at the plant include an amine unit, heaters, turbine generators and turbine compressors, boilers, and flares.[591]

In Oxy's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Natural Gas Simple Cycle Solar Centaur 40-4002 Turbines (Units ES-06/07 & ES-08/09)
- Natural Gas Simple Cycle Solar Centaur 40-4702 Turbine (Unit ES-10/11)
- Amine Gas Treating Units.[592]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[593] The following provides a review of the company's four-factor analyses. Comments on the four-factor analysis for the amine gas treating units are provided further below in Section XXIII.

A. Interest Rate Used in Cost Analyses.

Oxy used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[594] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest

[588] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.
[589] Title V Operating Permit No. P103-R3, OXY USA WTP Limited Partnership Indian Basin Gas Plant, 11/1/2019, at A3.
[590] *Id.*
[591] *Id.* at A7-A8.
[592] November 2019 Regional Haze Four-Factor Analysis for Oxy Indian Basin Gas Plant at 1-2.
[593] *Id.*
[594] *Id.* at Appendix B Cost Analysis Calculations.

rate.[595] The current bank prime rate is 3.25%.[596] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[597] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[598] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

B. Natural Gas Simple Cycle Solar Centaur 40-4002 Turbines (Units ES-06/07, ES-08/09, and ES-10/11)

The combustion turbines evaluated for controls at the Indian Basin Gas Plant are all Solar Centaur turbines that were manufactured in 1980.[599] The turbines have a permitted capacity of 4000 hp (Units ES-06/07 and ES-08/09) and 4700 hp (Unit ES-10/11).[600] The units each are either routed to a heat recovery generator or a bypass stack.[601] Units ES-06/07 and ES-08/09 are each subject to a NOx limit of 15.4 lb/hr and 67.4 tpy, and Unit ES-10/11 is subject to a 23.7 lb/hr NOx limit and 104.0 tpy.[602]

Oxy only evaluated one control technology for the combustion turbines: SoLoNOx combustion technology. Oxy did not evaluate SCR. Yet, SCR is a technically feasible control technology for combustion turbines.

1. Evaluation of SoLoNOx for Solar Centaur Turbines at Indian Basin Gas Plant

Oxy states that SoLoNOx is available for the existing Solar Centaur combustion turbines, but it would require the 4002 turbines at Units ES-06/07 and ES-08/09 to be uprated to model 4702 to support the SoLoNOx technology.[603] Oxy states that such controls could reduce NOx to 25

[595] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[596] https://www.federalreserve.gov/releases/h15/.
[597] https://fred.stlouisfed.org/series/DPRIME.
[598] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.
[599] Title V Operating Permit No. P103-R3, OXY USA WTP Limited Partnership Indian Basin Gas Plant, 11/1/2019, at A7.
[600] *Id.*
[601] *Id.*
[602] *Id.* at A10.
[603] November 2019 Regional Haze Four-Factor Analysis for Indian Basin Gas Plant at 2-3.

ppm.[604] Based on a comparison to Oxy's reported recent testing data for the units, SoLoNOx would reduce NOx by 75% at Units ES-06/07 and ES-08/09 and by 84% at Unit ES-10/11. It also must be noted that Oxy's capital cost estimates for installation of SoLoNOx at Units ES-06/07 and ES-08/09 (Solar Centaur T4002 turbines) are significantly higher than the costs to upgrade the same model turbines at Kutz Canyon Gas Plant. Specifically, Units 1-6 at Kutz Canyon Gas Plant are the same model turbines (Solar Centaur T4002) and would also need to be uprated to model T4702 with the installation of SoLoNOx.[605] Yet, Harvest Four Corners identified the capital cost for SoLoNOx at Units 1-6 of the Kutz Canyon facility as $467,400 with annual operations and maintenance costs of $22,500[606] whereas Oxy identified the capital cost for SoLoNOx at the same model turbines at Units ES-06/07 and ES-08/09 three times as much at $1,510,295 and with a higher operations and maintenance cost of $30,407 per year.[607]

While Oxy submitted supplemental information to NMED in a February 2020 submittal, the supplemental information appears to be for a different turbine model and also is from four years ago. Specifically, in response to NMED's request for the vendor specifications for the SoLoNOx costs and emission rate guarantee, Oxy submitted a sheet on "Predicted Emission Performance" for SoLoNOx at a Centaur 40-4700S turbine with a NOx emission rate of 42 ppmvd and submitted cost data as confidential business information for a "similar unit that was installed at the facility."[608] Yet, the turbines being reviewed in this four-factor analysis are of a different model and of a model for which a 25 ppm NOx emission rate was evaluated for SoLoNOx. NMED must collect more current cost information as to why SoLoNOx at the combustion turbines currently being evaluated for controls at Indian Basin Gas Plant would cost three times as much at the Indian Basin Solar Centaur T4002 gas turbines compared to the Kutz Canyon Solar Centaur T4002 gas turbine

In terms of the life of SoLoNOx controls in the cost effectiveness analyses, Oxy's analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[609] In the table below, we revised Oxy's cost effectiveness analyses of SoLoNOx were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate.

[604] *Id.*
[605] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Gas Plant at 2-3.
[606] *Id.* at Appendix B (pdf 30 of document).
[607] November 2019 Regional Haze Four-Factor Analysis for Indian Basin Gas Plant at Appendix B (pdf pages 21-22 of document).
[608] February 2020 Four-Factor Addendum for Oxy Indian Basin Gas Plant at pdf page 3 and at Appendix A. Cost data in Appendix B is not publicly available.
[609] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

Table 37. Revised Cost Effectiveness of SoLoNOx at Units ES-06/07, ES-08/09, and ES-10/11 of the Indian Basin Gas Plant, to Reflect a 4.7% Interest Rate and a 25-Year Life

Unit	Oxy's Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	Oxy's Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25 Year Life
ES-06/07	$156,787	$3,809/ton	$134,367	$3,265/ton
ES-08/09	$156,787	$4,132/ton	$134,367	$3,542/ton
ES-10/11	$147,290	$1,834/ton	$127,096	$1,582/ton

Thus, the cost effectiveness of SoLoNOx at the Solar Centaur turbines based on Oxy's capital cost of SoLoNOx should be in the range of $1,582/ton to $3,542/ton assuming a more appropriate 25-year life at lower interest rate. However, assuming that the costs of SoLoNOx are instead the same as the capital and operating and maintenance costs for SoLoNOx (including uprating of the turbines) of the same model turbine (Solar T4002) at the Kutz Canyon plant, the cost effectiveness of SoLoNOx at Units ES-06/07 and 08/09 would be $1,328/ton at Unit ES-06/07 and $1,441/ton at Unit ES-08/09. It is thus imperative that NMED determine why Oxy's cost estimates for SoLoNOx at these units are so much more expensive as the costs for controls (and turbine uprates) at the same model turbines as Units 1-6 of the Kutz Canyon Gas Plant.

2. Evaluation of SCR for the Solar Centaur Combustion Turbines at the Indian Basin Gas Plant

Oxy did not evaluate SCR as a control option for any of the combustion turbines at Indian Basin Gas Plant. Oxy acknowledged that Solar Turbines indicated that SCR is an available technology for the Solar Centaur turbines at Indian Basin Gas Plant, but Oxy determined that the additional power demands of SCR make the controls infeasible because the power at the plant would "need to be upgraded significantly and re-designed in order to power the SCR controls."[610] If the power at the plant would need to be upgraded to accommodate SCR, that should be evaluated as part of the cost of SCR rather than deem the control as technically infeasible. Further, NMED should request information from Oxy to determine whether the power would need to be upgraded for SCR systems at just one combustion turbine, or if the company's claim of power supply upgrades apply to SCR systems installed at all three combustion turbines. SoLoNOx at Unit ES-10/11 is very cost effective and will reduce NOx by 84%. Thus, it is likely SCR is the better control choice just for units ES-06/07 and ES-08/09, for which SoLoNOx has higher cost effectiveness values and will only result in 75% control. NMED should request that Oxy look into the option of shared SCR reactor for these two units, which could reduce electricity needs as well as reduce costs of control.

SCR would be more effective at reducing NOx at the Solar Centaur combustion turbines than SoLoNOx. As presented NPCA's Oil and Gas Four-Factor Report, NESCAUM assumed 90%

[610] November 2019 Regional Haze Four-Factor Analysis for Indian Basin Gas Plant at 2-4.

control with SCR in its 2000 Status Report to control small gas turbines down to 15 ppmv.[611] SCR at Units ES-06/07 and ES-08/09 of the Indian Basin Gas Plant should be able to at least achieve a 15 ppmv NOx limit, which reflects 85% NOx control at each unit.

Based on the fact that the combustion turbines at its Eunice Gas Plant (Units 17A, 18B, 19A, 25A, and 26A) evaluated for SCR by DCP Midstream are of similar size as the Indian Basin Gas Plant turbines, one would expect SCR to have a similar cost effectiveness. As shown in Table 9 above, the cost effectiveness SCR at the DCP Eunice Gas Plant turbines ranged from $2,600/ton to $3,800/ton (assuming a 4.7% interest rate and 25-year life). Thus, one would expect the similar (or same) model turbine and similar size units at Indian Basin Gas Plant combustion turbines to have a similar cost effectiveness of SCR to achieve 15 ppmv at 15% O_2.

Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[612] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[613] NMED should require Oxy to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

XVII. Enterprise South Carlsbad Compressor Station

The Enterprise South Carlsbad Compressor Station is a natural gas compressor station and dew point plant.[614] According to a January 2020 NMED Statement of Basis for a Title V Permit modification,[615] after compression, the gas is sent to an amine unit to remove CO2. Water is then removed from the treated gas from the amine unit by routing through a glycol dehydrator. Salable hydrocarbons are then removed. The compressed gas then has liquids removed in a three-phase separator. Dry gas is sent into a pipeline for transport. The gas stream from the three-phase separator is used as turbine fuel along with other fuel if needed from the discharge residue gas stream or the gas stream from the condensate stabilizer. The facility is located

[611] NPCA March 2020 Oil and Gas Four-Factor Report at 74-75. *See also* NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15), available at http://www.nescaum.org/documents/nox-2000.pdf/view.
[612] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.
[613] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.
[614] NMED Statement of Basis, Title V Minor Modification, Enterprise Fields Services, LLC, South Carlsbad Compressor Station, 1/10/2020, at 1.
[615] *Id.*

about 2.8 miles northwest of Loving, New Mexico in Eddy County.[616] The plant consists of two compressors driven by natural gas-fired combustion turbines, a glycol reboiler, an amine heater, tanks, and a flare, among other air emissions sources.[617]

In Enterprise's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Solar Centaur T4702 Turbines (Units 1 and 2).[618]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[619] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

Enterprise used an 8.38% interest rate in the cost analyses for the controls evaluated in its 4-factor analyses.[620] This is an unreasonably high interest rate for cost effectiveness analyses. EPA's Control Cost Manual indicates that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[621] The current bank prime rate is 3.25%.[622] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[623] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. However, in a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[624] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. Enterprise's use of an 8.38% interest rate is unreasonably high and overstates the cost effectiveness of pollution controls evaluated in the four-factor analyses.

[616] Title V Permit No. P130-R3 issued 3/8/18 for South Carlsbad Compressor Station at A3.
[617] *Id.* at A6-A7.
[618] November 2019 Regional Haze Four-Factor Analysis for South Carlsbad Compressor Station at 1-2.
[619] *Id.*
[620] *Id.* at Section 8.0 Supporting Documentation.
[621] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[622] https://www.federalreserve.gov/releases/h15/.
[623] https://fred.stlouisfed.org/series/DPRIME.
[624] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

B. Solar Centaur T4702 Turbines (Units 1 and 2)

The combustion turbines evaluated for controls at the South Carlsbad Compressor Station are both model T4702 Solar Centaur turbines that were manufactured in 2004.[625] The turbines have a permitted capacity of 4328 hp and a heat input of 42.8 MMBtu/hr.[626] The units each power a compressor engine.[627] The units are each subject to a NOx limit of 27.0 lb/hr and 90.8 tpy.[628]

Enterprise only evaluated one control technology for the combustion turbines: SoLoNOx combustion technology. Enterprise did not evaluate SCR. Yet, SCR is a technically feasible control technology for combustion turbines.

1. Evaluation of SoLoNOx for Solar Centaur Model T4702 Turbines

Enterprise states that SoLoNOx is available for the existing Solar Centaur model T4702 combustion turbines and that the controls could reduce NOx to 25 ppm.[629] Oxy states that such controls could reduce NOx to 25 ppm.[630] According to Enterprise's Four-Factor Analysis, SoLoNOx would reduce NOx by 64% at Unit 1 and by 66% at Unit 2.[631]
In terms of the life of SoLoNOx controls in the cost effectiveness analyses, Enterprise's analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[632] In the table below, we revised Enterprise's cost effectiveness analyses of SoLoNOx were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate.

Table 38. Revised Cost Effectiveness of SoLoNOx at Units 1 and 2 of the South Carlsbad Compressor Station, to Reflect a 4.7% Interest Rate and a 25 Year Life

Unit	Enterprise's Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	Enterprise's Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25 Year Life
1	$178,387	$8,584/ton	$130,180	$6,265/ton
2	$178,387	$6,629/ton	$130,180	$4,838/ton

[625] Title V Permit No. P130-R3 issued 3/8/18 for South Carlsbad Compressor Station at A6
[626] *Id.*
[627] *Id.*
[628] *Id.* at A9.
[629] November 2019 Regional Haze Four-Factor Analysis for South Carlsbad Compressor Station at 2-2.
[630] *Id.*
[631] *Id.* at 3-1.
[632] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

Thus, the cost effectiveness of SoLoNOx at the Solar Centaur T4702 turbines should be in the range of $4,800/ton to $6,200/ton assuming a more appropriate 25-year life at lower interest rate. The cost effectiveness of SoLoNOx at Units 1 and 2 of the South Carlsbad Compressor Station are much higher than the cost effectiveness of SoLoNOx at Unit ES-10/11 of the Indian Basin Gas Plant, despite the turbine models being the same Solar Centaur T4702 model. It appears this is due to the low 2016 emission rates of the Units 1 and 2 at the South Carlsbad Compressor Station. As discussed in Section I.B.1. of this report, it is imperative that NMED ensure that the emissions considered as baseline emission for cost effectiveness analyses be a reasonable estimate of current and future NOx emissions. The 2016 emissions reported by Enterprise for Units 1 and 2 are less than half of the NOx emission limits for the units, despite the units both operating 8,544 hours in 2016 (or 97.2% of the available hours in a year). These low 2016 NOx emissions either reflect the need to reduce the allowable emission limits for the units to more accurately reflect current emissions levels or the 2016 emissions data may not have been measured when the units were operating at maximum capacity. If the baseline NOx emissions are going to make the difference for NMED as to whether a pollution control is cost effective or not (especially if that pollution control is considered to be cost effective for other similar size or same model turbines, then NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on an accurate estimate of emissions expected in 2028.

2. Evaluation of SCR for the Solar Centaur T4702 Turbines at the South Carlsbad Compressor Station

Enterprise did not evaluate SCR as a control option for the Units 1 and 2 combustion turbines. Enterprise states the South Carlsbad facility was designed and constructed without plans for installation of SCR, and that based on size estimated provided by CECO-Peerless, Enterprise determined that it is "not possible" to install SCR at Units 1 and 2 of the South Carlsbad Compressor Station.[633]

While the facility and gas turbines may not have been originally designed to have space to accommodate SCR, that is typically the case with most SCR retrofits. As such, there have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints. For example, for many large coal-fired power plants, SCR reactors have been elevated above the air preheaters. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new foundations to make way for the SCR reactor.[634] Thus, before NMED accepts a very brief claim of retrofit difficulty of SCR at any emissions unit being evaluated for reasonable progress controls, it is imperative that NMED ask Enterprise for a site plan and photos that shows whatever space constraints are being

[633] November 2019 Regional Haze Four-Factor Analysis for South Carlsbad Compressor Station at 2-3.
[634] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, , available at https://www.onepetro.org/conference-paper/SPE-66501-MS.

claimed, and that NMED ask Enterprise to consult with SCR vendors for options for SCR installation at the gas turbines of South Carlsbad Compressor Station. In addition, there may be other options for the location of the SCR system. Depending on the proximity of the gas turbines, it is possible that one SCR reactor could be used by both Units 1 and 2, which would reduce costs and potentially be easier to install at the site. NMED must require all possibilities for SCR installation be evaluated and documented by Enterprise. The state must not simply discount this highly effective NOx control based on a claim of some retrofit difficulty.

SCR would be more effective at reducing NOx at the South Carlsbad combustion turbines than SoLoNOx. As presented NPCA's Oil and Gas Four-Factor Report, NESCAUM assumed 90% control with SCR in its 2000 Status Report to control small gas turbines down to 15 ppmv.[635] That would reflect a 78% reduction in NOx emissions at Units 1 and 2. However, because SCR can achieve NOx reductions of 90%, SCR could be even more effective at reducing NOx from these units.

Based on the fact that the combustion turbines at its Eunice Gas Plant (Units 17A, 18B, 19A, 25A, and 26A) evaluated for SCR by DCP Midstream are of similar size as the South Carlsbad Compressor Station turbines, one would expect SCR to have a similar cost effectiveness. As shown in Table 9 above, the cost effectiveness SCR at the DCP Eunice Gas Plant turbines ranged from $2,600/ton to $3,800/ton (assuming a 4.7% interest rate and 25-year life). Thus, one would expect the similar (or same) model turbine and similar size units at Indian Basin Gas Plant combustion turbines to have a similar cost effectiveness of SCR to achieve 15 ppmv at 15% O_2.

Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[636] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[637] NMED should require Enterprise to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

[635] NPCA March 2020 Oil and Gas Four-Factor Report at 74-75. *See also* NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15), available at http://www.nescaum.org/documents/nox-2000.pdf/view.

[636] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.

[637] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.

XVIII. El Paso Natural Gas Company – Blanco Compressor Station A

The El Paso Natural Gas Company, LLC. (EPNG) Blanco Compressor Station A is located in San Juan County. NMED has described the facility processes as follows:

The Blanco Compressor Station A is a natural gas compressor station that compresses natural gas for the purpose of transportation to another facility or a major transportation pipeline.[638]

According to the permit, the plant includes 14 2-stroke lean-burn reciprocating internal combustion engines (RICE).[639] In EPNG's four-factor submittal, the company evaluated air pollution controls for these units:

- Cooper-Bessemer 2SLB RICE GMV10-TF: Units A01 through A14.[640]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[641] The following provides a review of the company's four-factor analyses.

A. Units A01 through A14: Cooper-Bessemer GMV10-TF 2-Stroke Lean-Burn Compressor Engines

Units A01 through A14 are 2-stroke lean-burn RICE that were constructed in 1953, each with a capacity of 943 hp.[642] The units each have an hourly NOx limit of 21.9 lb/hr and an annual NOx limit of 95.97 tpy.[643]

1. Use of Low Emission Combustion Technology

EPNG presents three options for reducing NOx emissions from these compressor engines, with varying low emission combustion (LEC) control techniques to meet NOx emission levels of 3 g/hp-hr, 1 g/hp-hr, and 0.5 g/hp-hr. Uncontrolled NOx emissions (tpy) are based on 2016 emissions. The 2016 actual emissions for these units and the allowable NOx emission rates are shown in the table below.[644]

[638] Title V Operating Permit P048-R3 for Blanco Compressor Station A at 4.
[639] *Id.* at 6-7.
[640] October 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Blanco Compressor Station A at 5.
[641] *Id.* at 3.
[642] Title V Operating Permit P048-R3 for Blanco Compressor Station A at 6-7.
[643] *Id.* at 8.
[644] October 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Blanco Compressor Station A at 5.

Table 39. EPNG Blanco Compressor Station A 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	Allowable NOx Emissions [tpy]	2016 NOx Emissions [tpy]
A01	943	95.97	73.711
A02	943	95.97	0.025
A03	943	95.97	54.915
A04	943	95.97	1.093
A05	943	95.97	3.081
A06	943	95.97	0.613
A07	943	95.97	65.341
A08	943	95.97	0.019
A09	943	95.97	27.382
A10	943	95.97	0.019
A11	943	95.97	48.253
A12	943	95.97	0.016
A13	943	95.97	82.061
A14	943	95.97	0.019

It appears that many of these units operate infrequently, with several emitting less than 1 tpy in 2016. NMED should request more information on the typical operating schedules for these engines to ensure that EPNG's four-factor analysis is based on usage that is expected in 2028.

EPNG's four-factor analysis is based on detailed cost estimates for retrofitting these units with LEC technologies; control costs include capital costs and net annual costs (annual recurring costs).[645] EPNG does not provide any details on the source of the cost information included in the four-factor analysis; we assume they represent current costs (2019$). These cost estimates are high, at $138—$217/hp, compared to other capital cost estimates for LEC controls at other similar engines.[646] EPNG presents cost effectiveness, in dollars per ton of NOx reduced, ranging from $32K/ton to as high as $2.9M/ton.[647] However, these cost effectiveness figures do not take into account the annualized costs over the lifetime of the controls, they are simply the total per unit capital cost divided by the NOx emissions reductions from 2016 emissions. The following three tables present the cost effectiveness based on EPNG's capital cost estimates—for Options 1, 2, and 3—annualized over the life of the controls. Note, this updated analysis uses an interest rate of 4.7%, reflective of current and likely near future interest

[645] *Id.* at 4 and 10.
[646] *See, e.g.,* Four-Factor analyses for Saunders Gas Plant (Cooper-Bessemer 2SLB RICE at $90-$138/hp), Roswell Compressor Station No. 9 (Cooper-Bessemer 4SLB RICE at $90/hp), and Jal No. 3 (Cooper-Bessemer 2SLB RICE at $123/hp).
[647] *Id.*

rates.[648] Further note, the LEC controls are assumed to last 25 years, consistent with other cost effectiveness analyses submitted to NMED for LEC controls.[649]

Table 40. Cost Effectiveness of LEC at Uncontrolled Blanco Compressor Station A Units A01 through A14 for Option 1 (3 g/hp-hr), Assuming a 4.7% Interest Rate and a 25-Year Life

Unit	Capital Cost of LEC to Reduce NOx Option 1 3 g/hp-hr [assuming 2019$]	Total Annualized Costs	NOx Removed, tpy Based on 2016 Source Data	Cost Effectiveness of LEC at 3 g/hp-hr [2019$], $/ton
A01	$1,884,728	$129,734	52.718	$2,461
A02	$1,884,728	$129,734	0.018	$7,207,430
A03	$1,884,728	$129,734	39.275	$3,303
A04	$1,884,728	$129,734	0.782	$165,900
A05	$1,884,728	$129,734	2.204	$58,863
A06	$1,884,728	$129,734	0.439	$295,521
A07	$1,884,728	$129,734	46.732	$2,776
A08	$1,884,728	$129,734	0.014	$9,266,695
A09	$1,884,728	$129,734	19.584	$6,624
A10	$1,884,728	$129,734	0.014	$9,266,695
A11	$1,884,728	$129,734	34.511	$3,759
A12	$1,884,728	$129,734	0.012	$10,811,145
A13	$1,884,728	$129,734	58.690	$2,210
A14	$1,884,728	$129,734	0.014	$9,266,695

Table 41. Cost Effectiveness of LEC at Uncontrolled Blanco Compressor Station A Units A01 through A14 for Option 2 (1 g/hp-hr), Assuming a 4.7% Interest Rate and a 25-Year Life

Unit	Capital Cost of LEC to Reduce NOx Option 2 1 g/hp-hr [assuming 2019$]	Total Annualized Costs	NOx Removed, tpy Based on 2016 Source Data	Cost Effectiveness of LEC at 1 g/hp-hr [2019$], $/ton
A01	$2,975,000	$204,782	66.713	$3,070
A02	$2,975,000	$204,782	0.022	$9,308,261
A03	$2,975,000	$204,782	49.701	$4,120
A04	$2,975,000	$204,782	0.989	$207,059
A05	$2,975,000	$204,782	2.789	$73,425
A06	$2,975,000	$204,782	0.555	$368,976
A07	$2,975,000	$204,782	59.138	$3,463

[648] As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

[649] See 2019 Four-Factor submittals for Roswell Compressor Station and Jal No. 3 which both assume 25-year life of controls for LEC.

Unit	Capital Cost of LEC to Reduce NOx Option 2 1 g/hp-hr [assuming 2019$]	Total Annualized Costs	NOx Removed, tpy Based on 2016 Source Data	Cost Effectiveness of LEC at 1 g/hp-hr [2019$], $/ton
A08	$2,975,000	$204,782	0.017	$12,045,984
A09	$2,975,000	$204,782	24.783	$8,263
A10	$2,975,000	$204,782	0.017	$12,045,984
A11	$2,975,000	$204,782	43.673	$4,689
A12	$2,975,000	$204,782	0.015	$13,652,116
A13	$2,975,000	$204,782	74.271	$2,757
A14	$2,975,000	$204,782	0.017	$12,045,984

Table 42. Cost Effectiveness of LEC at Uncontrolled Blanco Compressor Station A Units A01 through A14 for Option 3 (0.5 g/hp-hr), Assuming a 4.7% Interest Rate and a 25-Year Life

Unit	Capital Cost of LEC to Reduce NOx Option 3 0.5 g/hp-hr [assuming 2019$]	Total Annualized Costs	NOx Removed, tpy Based on 2016 Source Data	Cost Effectiveness of LEC at 0.5 g/hp-hr [2019$], $/ton
A01	$2,804,837	$193,069	70.212	$2,750
A02	$2,804,837	$193,069	0.023	$8,394,291
A03	$2,804,837	$193,069	52.308	$3,691
A04	$2,804,837	$193,069	1.041	$185,465
A05	$2,804,837	$193,069	2.935	$65,781
A06	$2,804,837	$193,069	0.584	$330,597
A07	$2,804,837	$193,069	62.240	$3,102
A08	$2,804,837	$193,069	0.018	$10,726,039
A09	$2,804,837	$193,069	26.082	$7,402
A10	$2,804,837	$193,069	0.018	$10,726,039
A11	$2,804,837	$193,069	45.963	$4,201
A12	$2,804,837	$193,069	0.016	$12,066,794
A13	$2,804,837	$193,069	78.166	$2,470
A14	$2,804,837	$193,069	0.018	$10,726,039

For many of these units, LEC controls can be cost effective for reducing NOx emissions to emission rates as low as 0.5 g/hp-hr. NMED must request a revised four-factor analysis from EPNG for the Blanco Compressor Station A that includes the annualization of costs. Also, NMED should request additional information on the usage of these engines to determine if the units are consistently used as in 2016 or if usage varies from year to year. NMED must ensure that the cost effectiveness analyses for LEC evaluated for the company's four-factor analyses are based on a more comprehensive representation of emissions reduction and operating hours expected in 2028.

2. Use of SCR

EPNG did not evaluate SCR for Units A01 through A14 primarily because it claimed that it was not technically feasible for this engine type.[650] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly because EPNG has not found LEC to be a cost effective NOx reduction strategy for some of these units.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[651]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[652] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[653] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

XIX. Transwestern Pipeline Company Roswell Compressor No. 9

The Transwestern Pipeline Company (Transwestern) Roswell Compressor Station No. 9 is a natural gas compressor station located about 5 miles north of Roswell, New Mexico in Chaves

[650] October 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Blanco Compressor Station A at 9.
[651] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[652] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[653] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

County.[654] The plant consists of two natural gas-fired four-stroke lean-burn compressor engines compressors and a natural gas-fired rich burn engine used as a generator, as well as several tanks and other emissions sources.[655] The compressor station also has two electric-driven compressor engines with no associated air emissions.[656] In Transwestern's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Two Four-Stroke Lean-Burn RICE (Units 903 and 904).[657]

The rich burn generator engine is used as an emergency generator and operates less than 100 hours per year, and so was not evaluated for controls.[658] The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses. The following provides a review of the company's four-factor analyses.

A. Lean Burn Natural Gas-Fired Compressor Engines (Units 903 and 904)

The primary sources of NOx emissions at the Roswell Compressor Station No. 9 are two four-stroke lean burn natural gas-fired RICE (Units 903 and 904). The engines are both 4,500 hp Cooper-Bessemer LSV-16G compressor engines used for transportation of natural gas.[659] The engines were constructed in 1959, and are subject to allowable emission limits of 125 lb/hr and 547.5 tpy each.[660]

According to documentation submitted with the four-factor analysis, the 2016 emissions and operating hours used as baseline were as follows:

Table 43. Units 903 and 904 of Roswell Compressor Station No. 9 2016 Emissions and Operating Hours[661]

Unit No.	NOx Emission Rate, lb/hr	2016 Operating Hours	NOx Emissions, tpy
903	37.19 (Tested)	3,607	67.07
904	125 (PTE)	971	60.69

The source's Title V renewal application indicates that the allowable annual number of operating hours for Units 903 and 904 was increased from 6,620 to 8,760, which was the

[654] Title V Permit No. P154-R4, Roswell Compressor Station No. 9, 9/28/2018, at A3.
[655] *Id.* at A6.
[656] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[657] *Id.* at 2.
[658] *Id.*
[659] *Id.*
[660] Title V Permit No. P154-R4, Roswell Compressor Station No. 9, 9/28/2018, at A7.
[661] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, Appendix A at 1. Apparently, the company only had NOx emissions test data for Unit 903.

allowable number of hours in Permit No. P154-R2M1.[662] So presumably the 2016 operating hours are lower than what might be expected in current and future years for these units, especially for Unit 904. And, in fact, a review of the facility's NOx emissions from 2016 through 2019 show an increase in NOx emissions as shown in the table below.

Table 44. Roswell Compressor Station No. 9 NOx Emissions 2016-2019, as Presented in NMED's Emissions Analysis Tool

2016	2017	2018	2019
74.4 tons	185.5 tons	136.5 tons	436.8 tons

NOx emissions are over five times higher in 2019 than they were in 2016. And NOx emissions in all years since 2016 are significantly higher. And it is safe to assume that the bulk of those NOx increases are coming from the Units 903 and 904 lean burn compressor engines, because the only other sources of NOx emissions at the compressor station are Unit 921 (four-stroke rich burn emergency generator engine operating less than 100 hours per year) and two thermal oxidizers. These three NOx sources are limited to a combined total NOx emissions of 27.54 tons per year.[663] Even if we assume that these three units emitted NOx at their allowable emissions of 27.54 tons per year total, that means over 400 tons of NOx were emitted in 2019 by Units 903 and 904, rather than the 127.76 tons per year in total assumed in Transwestern's four-factor cost effectiveness analysis.[664] NMED must ensure that Transwestern's cost effectiveness analysis of controls is based on emissions expected in 2028. Given the significant increases in emissions since 2016 and the permitted increased levels of operation, 2016 emissions should not be used as baseline emissions in the company's cost effectiveness analysis for controls. Use of more recent data would result in more favorable cost effectiveness values because of the increased reduction in NOx that would occur from more recent emissions levels.

1. Evaluation of Low Emissions Combustion for Units 903 and 904

Transwestern assumes a controlled NOx emission rate from LEC retrofits on units 903 and 904 of 2.5 g/hp-hr.[665] For unit 903, Transwestern reports that this represents a 33% reduction from baseline NOx emission rates that are based on the 2016 emissions inventory.[666] For unit 904, Transwestern reports that this represents an 80% reduction from the unit's permitted NOx emission rate; according to Transwestern, "permitted hourly NO_X emission rates were used for Unit 904 in this analysis due to the 2016 emissions inventory showing lower NO_X emission rates

[662] February 1, 2017 Title V Operating Permit Renewal Application, Permit P154-R3M1 Transwestern Pipeline Company, LLC Roswell Compressor Station No. 9 Section 3 Page 2.
[663] *See* Title V Permit No. P154-R4, Roswell Compressor Station No. 9, 9/28/2018, at A8.
[664] Note, Transwestern's four-factor analysis is based on PTE emissions for unit 904. Even so, actual emissions in 2019 are much higher that what was used in the company's four-factor analysis.
[665] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Roswell Compressor Station No. 9 at 3 and Appendix A.
[666] *Id.* Appendix A.

than what was feasible to obtain by the engine vendor."[667] The permitted maximum hourly NOx emission rate of 125.0 lb/hr for these units is significantly higher than the 2016 emissions inventory data used for baseline emissions, even for unit 903. The allowable hourly NOx emission rate is equivalent to 12.6 g/hp-hr for these 4,500 hp engines. The source's Title V renewal application notes that the NOx emission factors are based on the permitted hourly rate in Permit No. P154-R2M1; it's not clear if the rates are based on stack testing or AP-42 emission factors but since all other emission factors (besides NOx) are identified as EPA AP-42 emission factors it's assumed that the permitted hourly rates are either based on stack tests or are source requested limits.[668] So for both units, emissions reductions to meet a controlled NOx rate of 2.5 g/hp-hr, based on a baseline emission rate that is reflective of the units' allowable emission rate, represents an 80% reduction in NOx emissions.

In January 2020, Transwestern submitted additional information in response to a request from NMED, including the specific technologies included in the quote from Cooper Machinery for LEC upgrades that lower NOx emissions to 2.5 g/hp-hr (e.g., precombustion chambers, turbocharger upgrades, larger intercoolers, etc.).[669]

It's possible that the controlled emission rate with LEC for these specific engines could be even lower that 2.5 g/hp-hr. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[670] EPA's Alternative Control Techniques document for RICE includes emissions test results for Clean Burn, low-emission retrofits (with a pre-combustion chamber) for LSV model dual-fuel engines demonstrating NOx emission rates of 2.0 g/hp-hr and as low as 1.27 g/hp-hr.[671] And, more generally, EPA's updated information on stationary RICE NOx emissions and control technologies concludes, for lean-burn engines, an emission rate of 2.0 g/bhp-hr is achievable for "new engines and most engines retrofitted with LEC technology."[672] Emissions reductions to meet a controlled NOx rate of 2 g/hp-hr, based on a baseline emission rate that is reflective of the units' allowable emission rate, represents an 84% reduction in NOx emissions.

Revising Transwestern's cost effectiveness analyses to reflect the quoted emissions reductions of 80% but based on potential operation at permitted levels for both units (not just for unit 904), results in more favorable cost effectiveness of these controls, as shown in the table below.

[667] *Id.* at 1 and Appendix A.
[668] February 1, 2017 Title V Operating Permit Renewal Application, Permit P154-R3M1 Transwestern Pipeline Company, LLC Roswell Compressor Station No. 9 pdf page 39.
[669] January 23, 2020 Additional Information for Four Factor Analysis Roswell Compressor Station at 2.
[670] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.
[671] *See* EPA 1993 Alternative Control Techniques Document for RICE at 5-82 and 5-83.
[672] *Id.* at 4-12.

Table 45. Cost Effectiveness of LEC at Uncontrolled Roswell Compressor Station No. 9 Units 903 and 904 to Reduce NO_x Levels to 2.5 g/hp-hr, Assuming 80% Control

Unit	Size [hp]	Capital Cost of LEC [current vendor quote, assuming 2019$]	Annual O&M Costs (15% of Capital Costs) [2019$]	Total Annualized Costs of LEC to Reduce NOx to 2.5 g/hp-hr (80% NOx Reduction) [2019$]	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC [2019$], $/ton
903	4,500	$1,800,000	$270,000	$342,000	3,607	180	$1,896/ton
904	4,500	$1,800,000	$270,000	$342,000	971	49	$7,044/ton

Note, the cost effectiveness of LEC controls would be more favorable for unit 904 at higher operating hours and would be more feasible for both units if they were able to meet controlled emission rates below 2.5 g/hp-hr, which, as discussed earlier, has been demonstrated for other LEC retrofits for similar engines. NMED should request that Transwestern research other available retrofit options from additional vendors that may be able to guarantee NOx emission rates less than 2.5 g/hp-hr.

2. Evaluation of SCR for Units 903 and 904

Although Transwestern identified concerns with utilization of SCR for the lean burn engines (which included reagent injection control, exhaust temperature requirements, variations in exhaust NO/NO2 ratio, and engine oil carryover), Transwestern evaluated SCR as a NOx control option for the Units 903 and 904 engines.[673] In the May 21, 2020 Review of SCR Claims for Lean Burn Engines report, these issues and methods to resolve these concerns were addressed.[674] Transwestern said as a result of its stated concerns, LEC is the preferred control. Yet, the company's cost analysis showed that SCR was more cost effective, and it can achieve 90% NOx reduction.[675]

Transwestern appears to have used EPA's SCR Chapter of its Control Cost Manual to either estimate annual operations and maintenance costs of SCR and used a formula from the December 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines to estimate capital costs for SCR.[676]

[673] *Id.* at 3-4.
[674] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[675] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 4-5 and Appendix A.
[676] December 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines at III-30.

Specifically, the NESCAUM formula which was based on only one case study for a RICE unit to "approximate" SCR capita costs for lean burn RICE is as follows:

$310,000 + ($72.7 x hp)[677]

This NESCAUM equation is twenty years old and is likely based on cost data from the 1990's. SCR has been implemented on numerous source types over the past twenty years, and the much wider-scale implementation and innovation in catalyst design has lowered the cost of SCR.[678] Yet, Transwestern's analysis escalated the capital costs developed with the above equation from the 2000 NESCAUM report by assuming the NESCAUM cost equation was based on 1994 costs and escalating to 2019, using the differences in the Consumer Price Index between 1994 and 2019.[679] EPA's Control Cost Manual cautions against escalating costs more than five years due to the potential for significant inaccuracies in price estimates.[680] EPA currently has a spreadsheet available to estimate the capital and operating costs for SCR. While the spreadsheet was developed for fossil fuel fired boilers, it can be used as an estimate for SCR at other natural gas-fired sources and, in fact, has been used oil and gas companies for several four-factor analyses submitted to NMED. Transwestern included the necessary information to be able to utilize the EPA SCR cost spreadsheet to estimate SCR costs for the Units 903 and 904 engines. Specifically, the company provided the hourly heat input in MMBtu/hr, the inlet NOx emission rate in lb/MMBtu, the engine fuel consumption in terms of Btu/hp-hr (with which the annual fuel consumption can be estimated based on the 2016 operating hours for each unit and each unit's rated horsepower of 4500), the flue gas flow rate in actual cubic feet per minute, and the SCR inlet temperature. The elevation for the location was estimated to be 3600 feet above sea level.

Using the unit-specific operating hours for 2016 and assuming 90% NOx reduction across the SCR, the cost effectiveness based on EPA's SCR spreadsheet is estimated as shown in the table below. Transwestern assumed a 25-year life of SCR, which was also assumed in the SCR cost effectiveness calculation presented below which is consistent with EPA's Control Cost Manual for the expected life of SCR at an industrial unit. For reasons discussed above in this report, a 4.7% interest rate was used rather than Transwestern's assumed 5.5% interest rate. (See, e.g., Section I.A. above).

[677] *Id*.
[678] See EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.
[679] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, Appendix A (pdf pages 15 and 17 of report).
[680] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.

Table 46. Estimated Cost Effectiveness of SCR Using EPA's SCR Cost Spreadsheet and 2016 Operational Data for Units 903 and 904 Cooper-Bessemer LSV-16G Compressor Engines at Roswell Compressor Station No. 9 (25-Year Life, 4.7% Interest Rate), 2018 $

Unit Number	Capital Cost	Operations and Maintenance Costs	Total Annual Costs	NOx Reduced from 2016 Emissions, tpy	Cost Effectiveness
903	$1,778,670	$25,746	$150,853	60	$2,449/ton
904	$1,832,960	$26,173	$128,846	55	$2,835/ton

In comparison, Transwestern's SCR cost estimates are much higher. The table below provides the company's SCR cost estimates for comparison to Table 46 above.

Table 47. Transwestern's Cost Effectiveness of SCR for Units 903 and 904 Cooper-Bessemer LSV-16G Compressor Engines at Roswell Compressor Station No. 9 (25-Year Life, 5.5% Interest Rate), 2019 $[681]

Unit Number	Capital Cost	Operations and Maintenance Costs	Total Annual Costs	NOx Reduced from 2016 Emissions, tpy	Cost Effectiveness
903	$1,100,282	$218,527	$262,538	60	$4,376/ton
904	$1,100,282	$255,446	$299,457	55	$5,445/ton

Interestingly, EPA's SCR cost spreadsheet estimates a much higher capital cost than Transwestern's escalation of NESCAUM's capital cost equation for RICE units. But what makes most of the differences in the cost estimates is Transwestern's operations and maintenance costs. A review of the company's cost data sheet found two significant errors that lead to the overstatement of operations and maintenance costs. First, an error was made in the calculation of catalyst volume by Transwestern, due to an error in the formula used for the NOx efficiency adjustment factor η_{adj}. The formula for η_{adj} in EPA's Control Cost Manual chapter for SCR is:

$$\eta_{adj} = 0.2869 + (1.058 \underline{x} \eta_{NOx})$$ [682]

However, Transwestern used the formula

$$\eta_{adj} = 0.2869 + (1.058 \mathbf{+} \eta_{NOx})$$ [683]

Transwestern's error resulted in a significant overestimate of the volume of catalyst, in which η_{adj} is a multiplier, which then resulted in an overestimate of annual catalyst replacement costs.

[681] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, Appendix A (pdf pages 13-14 of report).
[682] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 61 (Equation 2.23).
[683] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, Appendix A (pdf pages 16 and 18 of report).

In addition, Transwestern assumed 8,760 hours per year of operation in determining annual operations and maintenance costs which significantly overstated the costs of reagent, catalyst replacement, and labor.[684]

In summary, SCR is a more cost effective NOx control for the Units 903 and 904 engines at Roswell Compressor No. 9 compared to LEC which Transwestern estimated would have a cost effectiveness of $7,000/ton to $15,000/ton.[685]

XX. Transwestern Pipeline Mountainair Compressor Station

The Transwestern Pipeline Company (Transwestern) Mountainair Compressor Station is a natural gas compressor station located in Torrance County, New Mexico. NMED has described the facility processes as follows:

> The facility is a natural gas compressor station. The station is equipped with three 4,500- horsepower (hp) Cooper-Bessemer LSV-16SG compressor engines (701-703) and two 335- hp Ingersoll-Rand PSVG-6 generator engines (721-722), a pipeline condensate storage tank (T-006), and a mist extractor (MIST).[686]

In Transwestern's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Cooper-Bessemer 4SLB RICE LSV-16G: Units 701, 702, and 703.[687]

The rich burn generator engines are equipped with NSCR and are achieving 85% reduction in NOx emissions based on recent engine performance testing.[688] The selection of the 4SLB RICE units for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses. The following provides a review of the company's four-factor analyses.[689]

A. Lean Burn Natural Gas-Fired Compressor Engines (Units 701, 702, and 703)

The primary sources of NOx emissions at the Mountainair Compressor Station are three four-stroke lean-burn natural gas-fired RICE (Units 701, 702, and 703). The engines are each 4,500 hp Cooper-Bessemer LSV-16G compressor engines used for transportation of natural gas.[690]

[684] *Id.* at pdf pages 15-18.
[685] *Id.* at pdf page 13.
[686] Title V Permit No. P153-R3M1, Mountainair Compressor Station, 9/26/2016, at 3.
[687] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mountainair Compressor Station at 2.
[688] *Id.*
[689] *Id.* at 1.
[690] Title V Permit No. P153-R3M1, Mountainair Compressor Station, 9/26/2016, at 5-6.

The engines were constructed in 1960 (701 and 701) and 1967 (703), and are subject to allowable emission limits of 165.3 lb/hr and 724.2 tpy each.[691]

1. Baseline Emissions for Units 701, 702, and 703

According to documentation submitted with the four-factor analysis, the 2016 emissions and operating hours used as baseline were as follows:

Table 48. Units 701, 702, and 703 of Mountainair Compressor Station 2016 Emissions and Operating Hours[692]

Unit No.	2016 NOx Emission Rate, lb/hr	2016 Operating Hours	2016 NOx Emissions, tpy	NOx Allowable Emissions, tpy	NOx Allowable Emissions, lb/hr
701	59.07	1,535	45.34	724.2	165.3
702	98.03	3,116	152.73	724.2	165.3
703	100.86	4,586	231.27	724.2	165.3
TOTAL	258.0	9,237	429.34	2,172.6	495.9

The company's 2016 NOx emissions, used as baseline emissions, are significantly lower than the units' allowable emission limits of 165.3 lb/hr and 724.2 tpy each. And more recent actual emissions from the facility are also much higher.

In fact, the facility obtained a permit in 2016 that allowed for a three-fold increase in startup, shutdown, maintenance, and malfunction emissions because the facility was operating more due to increased volume of natural gas being processed at the facility.[693] Prior to 2016, NMED referred to the compressor station as a "peaking station."[694] A review of the facility's NOx emissions from 2016 through 2019 show a dramatic increase in NOx emissions as shown in the table below.

Table 49. Mountainair No. 7 Compressor Station NOx Emissions 2016-2019, as Presented in NMED's Emissions Analysis Tool

2016	**2017**	**2018**	**2019**
436.6 tons	449.2 tons	1,048.1 tons	932 tons

NOx emissions have more than doubled since 2016 at the Mountainair No. 7 Compressor Station. The most recent two year average NOx emissions are 990.05 tons compared to 436.6 tons of NOx emitted in the 2016 base year used in Transwestern's cost analysis. And it is safe

[691] *Id.*
[692] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mounatinair Compressor Station Appendix A at 1.
[693] *See* 9/26/2016 NMED Statement of Basis -Narrative for Title V Permit Significant Permit Modification for Mountainair No. 7 Compressor Station (Permit No. P153-R3M1) at 1.
[694] *Id.* at 3.

to assume that the bulk of those NOx increases are coming from the Units 701, 702, and 702 lean burn compressor engines, because the only other sources of NOx emissions at the compressor station are Units 721 and 722 (four-stroke rich burn generator engines) that are limited to a combined total NOx emissions of 90.9 tons per year.[695] If we assume that Units 721 and 722 emitted NOx at their allowable emissions of 90.9 tons per year total (which is not likely to occur),[696] that means at least 899.15 tons of NOx were emitted on average over 2018 to 2019 by Units 701, 702, and 703, rather than the 429.34 tons per year in total assumed in Transwestern's four-factor cost effectiveness analysis. NMED must ensure that Transwestern's cost effectiveness analysis of controls is based on emissions expected in 2028. Given the significant increases in emissions since 2016 and the permitted increased levels of operation, 2016 emissions should not be used as baseline emissions in the company's cost effectiveness analysis for controls. Use of more recent data would result in lower cost effectiveness values because of the increased reduction in NOx that would occur from more recent emissions levels.

2. Evaluation of Low Emissions Combustion for Units 701, 702, and 703

Transwestern assumes a controlled NOx emission rate from LEC retrofits on units 701, 702, and 703 of 2.5 g/hp-hr.[697] This represents a 58% (unit 701) and 75% (units 702 and 703) NOx emissions reduction from baseline NOx emission rates that are based on the 2016 emissions inventory.[698] The permitted maximum hourly NOx emission rate of 165.3 lb/hr for these units is significantly higher than the 2016 emissions inventory data used for baseline emissions. The allowable hourly NOx emission rate is equivalent to 16.7 g/hp-hr for each of these 4,500 hp engines. No test data are provided for these units and the source's recent Title V modification application does not specify the basis for the source's allowable NOx emission limits.[699] For both units, emissions reductions to meet a controlled NOx rate of 2.5 g/hp-hr, based on a baseline emission rate that is reflective of the units' allowable emission rate, represents an 85% reduction in NOx emissions.

It's possible that the controlled emission rate with LEC for these specific engines could be even lower that 2.5 g/hp-hr. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[700] EPA's

[695] *See* 9/26/2016 Title V Operating Permit No. P153-R3M1 for Mountainair Compressor Station (Station No. 7) at 3 and at 5-7.
[696] For example, in 2016, Units 701, 702, and 703 emitted 429.34 tons (based on what was reported for these units' 2016 emissions in the Mountainair No 7 Compressor Station Four-Factor Analysis in Appendix A). The total reported NOx emissions as shown in Table 49 above were 436.6 tons, which would mean Units 721 and 722 only emitted 7.26 tons of NOx in 2016.
[697] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mounatinair Compressor Station at 3 and Appendix A.
[698] *Id.* Appendix A.
[699] *See* March 3, 2016 Title V Operating Permit Application for Significant Modification, Permit P153-R3 Transwestern Pipeline Company, LLC Mountainair Compressor Station Section 6, Page 4.
[700] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.

Alternative Control Techniques document for RICE includes emissions test results for Clean Burn, low-emission retrofits (with a pre-combustion chamber) for LSV model dual-fuel engines demonstrating NOx emission rates of 2.0 g/hp-hr and as low as 1.27 g/hp-hr.[701] And, more generally, EPA's updated information on stationary RICE NOx emissions and control technologies concludes, for lean-burn engines, an emission rate of 2.0 g/bhp-hr is achievable for "new engines and most engines retrofitted with LEC technology."[702] Emissions reductions to meet a controlled NOx rate of 2 g/hp-hr, based on a baseline emission rate that is reflective of the units' allowable emission rate, represents an 88% reduction in NOx emissions. Revising Transwestern's cost effectiveness analyses to reflect higher baseline emission levels that are more in line with recent NMED actual emissions data, results in more favorable cost effectiveness of these controls, as shown in the table below. This revised analysis assumes baseline emissions that are reflective of more recent NMED emissions data (e.g., 899.15 tons per year for units 701, 702, and 703 based on 2018-2019 actual emissions and assuming units 721 and 722 concurrently operated at permitted allowable levels during that time). These annual emissions are distributed equally across units 701, 702, and 703 since 2018-2019 operating hours are not known. The table below presents cost effectiveness assuming an 85% reduction in NOx emissions, which reflect reducing hourly allowable NOx emission rates to a level of 2.5 g/hp-hr.

Table 50. Cost Effectiveness of LEC at Uncontrolled Mountainair Compressor Station Units 701, 702, and 703 to Reduce NO_x Levels to 2.5 g/hp-hr, Based on 2018-2019 Baseline Emission Levels Evenly Distributed Across Units 701, 702, and 703

Unit	Size [hp]	Total Annualized Costs of LEC to Reduce NOx to 2.5 g/hp-hr [2019$]	NOx Removed, tpy	Cost Effectiveness of LEC [2019$], $/ton
701	4,500	$342,000*	255	$1,341/ton
702	4,500	$342,000*	255	$1,341/ton
703	4,500	$342,000*	255	$1,341/ton

*Quote from Cooper Machinery Services 10/17/19

Note, if units 701, 702, and 703 operate with the same distribution as in 2016 (i.e., with unit 701 operating roughly 15% of the time, unit 702 operating 35% of the time, and unit 703 operating 50% of the time), the cost effectiveness would range from $900–$3,000/ton. And the cost effectiveness of LEC controls would be even more favorable, under any operating scenario, if LEC at these units were able to meet controlled emission rates below 2.5 g/hp-hr, which, as discussed earlier, has been demonstrated for other LEC retrofits for similar engines. NMED should request that Transwestern research other available retrofit options from additional

[701] *See* EPA 1993 Alternative Control Techniques Document for RICE at 5-82 and 5-83.
[702] *Id.* at 4-12.

vendors that may be able to guarantee NOx emission rates less than 2.5 g/hp-hr for these engines.

3. Use of SCR

Transwestern also evaluated SCR as a control for the four-stroke lean burn engines at Mountainair Compressor Station (Units 701, 702, and 703). The company did identify concerns with applicability of SCR to the two-stroke lean burn units including reagent injection control, exhaust temperature requirements, variations in the exhaust NO/NO_2 ratio, and engine oil carryover harming the SCR catalyst.[703] In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[704]

Irrespective of the company's concerns with applicability of SCR to the lean burn engines, Transwestern did conduct a cost effectiveness evaluation for SCR at Units 701, 702, and 703 assuming a target NOx emission rate of 0.060 to 1.02 g/hp-hr which purported reflects 90% reduction from current NOx emission levels.[705] Specifically, the company estimated the cost effectiveness of SCR at Unit 701 as $6,596/ton, at Unit 702 as $2,114/ton, and at Unit 703 as $1,372/ton.[706] The company's analyses show that SCR is more cost effective than LEC. Yet, these cost effectiveness values are in error and true cost effectiveness of SCR would be even lower, as discussed below.

One reason the cost effectiveness values are likely lower is because Transwestern relied on 2016 emissions as baseline emissions, but 2016 emissions were much lower than more recent years' emissions as discussed earlier.

Transwestern appears to have used a 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines to estimate capital costs for SCR.[707] Specifically, the NESCAUM formula which was based on only one case study for a RICE unit to "approximate" SCR capita costs for lean burn RICE is as follows:

$$\$310{,}000 + (\$72.7 \times hp)$$[708]

[703] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mountainair Compressor Station at 3.
[704] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[705] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mountainair Compressor Station at Appendix A.
[706] *Id.* at Appendix B.
[707] *Id.* at 8. *See also* December 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines at III-30.
[708] *Id*.

This NESCAUM equation is twenty years old and is likely based on cost data from the 1990's. SCR has been implemented on numerous source types over the past twenty years, and the much wider-scale implementation and innovation in catalyst design has lowered the cost of SCR.[709] Yet, Transwestern's analysis escalated the capital costs developed with the above equation from the 2000 NESCAUM report by assuming the NESCAUM cost equation was based on 1994 costs and escalating to 2019, using the differences in the Consumer Price Index between 1994 and 2019.[710] EPA's Control Cost Manual cautions against escalating costs more than five years due to the potential for significant inaccuracies in price estimates.[711]

EPA currently has a spreadsheet available to estimate the capital and operating costs for SCR. While the spreadsheet was developed for fossil fueled fired boilers, it can be used as an estimate for SCR at other natural gas-fired sources and, in fact, has been used oil and gas companies for several four-factor analyses submitted to NMED. Transwestern included the necessary information to be able to utilize the EPA SCR cost spreadsheet to estimate SCR costs for the Units 701-703 engines. Specifically, the company provided the hourly heat input in MMBtu/hr, the inlet NOx emission rate in lb/MMBtu, the engine fuel consumption in terms of Btu/hp-hr (with which the annual fuel consumption can be estimated based on the 2016 operating hours for each unit and each unit's rated horsepower of 4500), the flue gas flow rate in actual cubic feet per minute, and the SCR inlet temperature. The elevation for the location was estimated to be 6,519 feet above sea level (the elevation of the city of Mountainair, New Mexico)

.

Using the unit-specific operating hours for 2016 and assuming 90% NOx reduction across the SCR, the cost effectiveness based on EPA's SCR spreadsheet is estimated as shown in the table below. Transwestern assumed a 25-year life of SCR, which was also assumed in the SCR cost effectiveness calculation presented below which is consistent with EPA's Control Cost Manual for the expected life of SCR at an industrial unit. For reasons discussed above in this report, a 4.7% interest rate was used rather than Transwestern's assumed 5.5% interest rate. (See, e.g., Section I.A. above).

[709] See EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.

[710] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mountainair Compressor Station at Appendix B.

[711] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.

Table 51. Estimated Cost Effectiveness of SCR Using EPA's SCR Cost Spreadsheet and 2016 Operational Data for Units 701, 702, and 703 at Mountainair Compressor Station No. 7 (25-Year Life, 4.7% Interest Rate), 2018 $

Unit Number	Capital Cost	Operations and Maintenance Costs	Total Annual Costs	NOx Reduced from 2016 Emissions, tpy	Cost Effectiveness
701	$1,996,770	$22,760	$162,886	41	$3,989/ton
702	$1,996,397	$36,662	$176,761	137	$1,286/ton
703	$1,886,138	$44,591	$177,098	208	$850/ton

In comparison, Transwestern's SCR cost estimates are much higher. The table below provides the company's SCR cost estimates for comparison to Table 51 above.

Table 52. Transwestern's Cost Effectiveness of SCR for Units 701, 702, and 703 at Mountainair Compressor Station No. 7 (25-Year Life, 5.5% Interest Rate), 2019 $[712]

Unit Number	Capital Cost	Operations and Maintenance Costs	Total Annual Costs	NOx Reduced from 2016 Emissions, tpy	Cost Effectiveness
701	$1,100,282	$225,152	$269,152	40.81	$6,596/ton
702	$1,100,282	$246,513	$290,525	137.46	$2,114/ton
703	$1,100,282	$241,474	$285,485	208.14	$1,372/ton

Interestingly, EPA's SCR cost spreadsheet estimates a much higher capital cost than Transwestern's escalation of NESCAUM's capital cost equation for RICE units. But what makes most of the differences in the cost estimates is Transwestern's operations and maintenance costs. A review of the company's cost data sheet found two significant errors that lead to the overstatement of operations and maintenance costs. First, an error was made in the calculation of catalyst volume by Transwestern, due to an error in the formula used for the NOx efficiency adjustment factor η_{adj}. The formula for η_{adj} in EPA's Control Cost Manual chapter for SCR is:

$$\eta_{adj} = 0.2869 + (1.058 \underline{\mathbf{x}} \eta_{NOx})$$ [713]

However, Transwestern used the formula

$$\eta_{adj} = 0.2869 + (1.058 \mathbf{+} \eta_{NOx})$$ [714]

[712] October 2019 Regional Haze Four-Factor Analysis for Mountainair Compressor Station No. 7, Appendix A (pdf page 12 of report).
[713] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 61 (Equation 2.23).
[714] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, Appendix A (pdf pages 14, 16, and 18 of report).

Transwestern's error resulted in a significant overestimate of the volume of catalyst, in which η_{adj} is a multiplier, which then resulted in an overestimate of annual catalyst replacement costs.

In addition, Transwestern assumed 8,760 hours per year of operation in determining annual operations and maintenance costs which significantly overstated the costs of reagent, catalyst replacement, and labor.[715]

With these deficiencies in Transwestern's cost analysis along with its use of 2016 emissions to define the NOx emissions reduced with SCR, Transwestern's cost effectiveness values for SCR are greatly overstated. While the increased hours of operation would mean increased operational costs, the capital cost of SCR would remain the same. And the annual reduction in NOx emissions would be much greater (i.e., 90% control from 2018-2018 average NOx emissions versus 90% control from the much lower 2016 NOx emissions). Thus, with more recent NOx emissions used as baseline, SCR will be even more cost effective than shown above.

In summary, SCR is a more cost effective NOx control for the Units 701, 702, and 703 compared to LEC, which Transwestern estimated would have a cost effectiveness of $1,961/ton to $13,002/ton.[716] However, if more recent emissions data are used, the cost effectiveness of LEC would also be much lower than estimated by Transwestern at $1,341/ton.

XXI. Transwestern Pipeline Company – Corona Compressor Station

The Transwestern Pipeline Company, LLC. (Transwestern) Corona Compressor Station was not a facility for which NMED requested a four-factor analysis, yet the facility has a Q/d value (based on 2014 emissions) of 5.9. The closest Class I area to the plant is the White Mountains Wilderness, which is 60 kilometers away, according to the NMED Emissions Analysis Tool. The Corona Compressor Station is located in Lincoln County. NMED has described the facility processes as follows:

> The function of the facility is to compress natural gas. This facility receives natural gas from an upstream compressor station which goes through an inlet separator. The gas is then compressed by two (2) natural gas fired RICE compressors (units 801 and 802) and is sent to the next downstream compressor station. Two Waukesha generator engines supply electrical power to the station.[717]

According to the permit, the plant includes two 2-stroke lean-burn compressor engines, two 4-stroke rich-burn RICE, and two tanks.[718]

[715] *Id.* at pdf pages 15-18.
[716] *Id.* at pdf page 12.
[717] Title V Operating Permit P151-R3 for Corona Compressor Station at A3.
[718] *Id.* at A5.

A. Units 801 and 802: Cooper-Bessemer V-250 2-Stroke Lean-Burn Compressor Engines

Units 801 and 802 are Cooper-Bessemer V-250 2-stroke lean-burn RICE constructed in 1967 (801) and 1968 (802), each with a capacity of 5,000 hp.[719] The units each have an hourly NOx limit of 205.5 lb/hr and an annual NOx limit of 900 tpy.[720]

1. Use of Low Emission Combustion Technology

The uncontrolled allowable NOx emission rates for units 801 and 802 of 205.5 lb/hr are equivalent to 18.6 g/hp-hr for these 5,000 hp engines. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with low emission combustion (LEC) technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[721] In 2002, EPA collected data on emission rates of lean burn engines that have been retrofitted with LEC, including data from several state agencies for specific engine models.[722] Test results for eight Cooper-Bessemer V-250 engines ranged from 1.6 to 3.4 g/hp-hr, with an average controlled NOx rate of 2.9 g/hp-hr.[723] And, overall, EPA calculated the weighted average for installation of LEC technology retrofit on all of the large IC engines in the dataset to be 2.9 g/bhp-hr.[724] At this controlled emission rate, NOx emissions reductions for units 801 and 802 would be 84%. These emissions reductions could prevent up to 1,500 tons per year of NOx emissions from these two units, combined, for operation at permitted annual levels. NMED should request a four-factor analysis for these units to evaluate the cost effectiveness of controlling NOx emissions from these units with LEC to 2.9 g/hp-hr.

2. Use of SCR

SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[725]

[719] *Id.*
[720] *Id*. at A7.
[721] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.
[722] *See* EPA Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call (October 2003) at 15, *available at:* http://www.valleyair.org/workshops/postings/2011/8-18-11-rule4702/R4702%20APPF.pdf.
[723] *Id.* Table 4.
[724] *Id.* at 25.
[725] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.

If LEC is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[726] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[727] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should consider SCR as a potentially viable control option for lean burn engines in a company's analysis of available controls to achieve reasonable progress towards the national visibility goal.

B. Units 821 and 822: Waukesha F3520GU 4-Stroke Rich-Burn RICE

Units 821 and 822 are Waukesha F3520GU 4-stroke rich-burn RICE constructed in 1967, each with a capacity of 418 hp.[728] The units each have an hourly NOx limit of 18.5 lb/hr and a combined annual NOx limit of 83.4 tpy.[729]

1. Use of Non-Selective Catalytic Reduction

The uncontrolled allowable NOx emission rates for units 821 and 822 of 18.5 lb/hr are equivalent to 20.1 g/hp-hr for these 418 hp engines. NPCA's March 2020 Oil and Gas Four-Factor Report provides an analysis of the cost effectiveness of NSCR to reduce NOx emissions from rich-burn RICE by 94%.[730] This cost analysis is laid out below, as applied to these two specific units at the Corona Compressor Station.

EPA describes NSCR and potential controlled emission rates in its Alternative Control Techniques document for RICE:

> Catalyst vendors quote NOx emission reduction efficiencies of 90 to 98 percent. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 0.3 to 1.6 g/hp-hr….[731,732]

[726] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[727] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[728] *Id.* at A5.
[729] *Id*. at A7.
[730] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 17-20 and Table 7 at 26.
[731] EPA 1993 Alternative Control Techniques Document for RICE at 2-10 to 2-11.
[732] Note, employing NSCR to reduce NOx emissions from EPA's uncontrolled emission rate of 15.8 g/bhp-hr to 1.0 g/bhp-hr corresponds to a NOx emission reduction efficiency of 94%. This control efficiency is used in the analysis presented here as a reasonable achievable emission rate but certainly not the lowest possibility.

A cost effectiveness analysis of NSCR was performed in 2010 for EPA, to help determine national impacts associated with EPA's final rule for Reciprocating Internal Combustion Engine National Emission Standards for Hazardous Air Pollutants (RICE NESHAP).[733] The analysis, performed by E^C/R Incorporated, was based on 2009 cost data for retrofitting NSCR on existing 4SRB engines from industry groups, vendors, and manufacturers of RICE control technology. E^C/R Incorporated performed a linear regression analysis[734] on the data set to determine the following linear equation for annual cost, which includes annual operating and maintenance costs plus annualized capital costs based on a 7% interest rate and 10-year life of controls:

NSCR Annual Cost = $4.77 x (hp) + $5,697 (2009$)

The capital cost equation for retrofitting an air-to-fuel ratio controller (AFRC) and NSCR on a 4SRB engine was determined by E^C/R Incorporated to be, as follows:

NSCR Capital Cost = $24.9 x (hp) + $13,118 (2009$)

These relationships are derived from a data set that includes engines ranging in size from 50–3,000 hp.

The E^C/R document does not explain why it assumed a 10-year life of controls for estimating the annualized capital costs. The life of a RICE unit is generally much longer than ten years, and is often at least thirty years.[735] The assumed 10-year life was not based on the catalyst replacement timeframe, because the E^C/R operating costs took into account the cost for replacing the catalyst every three years, as well as replacing the thermocouple every 7.5 years, the crankcase filters every three months, the oxygen sensor on a quarterly basis, and rotating the catalyst for cleaning annually.[736] Thus, the assumed 10-year life of an NSCR system seems arbitrary. In cost analyses done in 2000 for EPA, an equipment life of NSCR of fifteen years was assumed.[737] The state of Colorado also recently assumed a 15-year life of NSCR for RICE

[733] Memo from E^C/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010), *available at*: https://www.epa.gov/sites/production/files/2014-02/documents/5_2011_ctrlcostmemo_exist_si.pdf.

[734] *Id.* The report notes that the linear equation has a correlation coefficient (R) of 0.7987, concluding that it "shows an acceptable representation of cost data."

[735] *See, e.g.*, EPRI, 20 Power Companies Examine the Role of Reciprocating Internal Combustion Engines for the Grid, *available at*: https://eprijournal.com/start-your-engines/. The authors also note that, in reviewing permits for gas processing facilities and compressor stations in New Mexico, it is not uncommon to have engines that were constructed from the 1950's to 1970's still operating at such facilities.

[736] Memo from E^C/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010), at 4 and at 11, 13, and 15.

[737] *See* August 11, 2000, E.H. Pechan & Associates, Inc., NOx Emissions Control Costs for Stationary Reciprocating Internal Combustion Engines in the NOx SIP Call States, at 5 and at A-2, *available at*: https://www3.epa.gov/ttn/ecas/regdata/cost/pechan8-11.pdf. *See also* EPA, Regulatory Impact Analysis for the NOx SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).

units.[738] Given that EPA assumed a selective catalytic reduction (SCR) system at an industrial fossil fuel-fired boiler has a life of 20-25 years,[739] it seems very likely that NSCR would have a useful life of at least fifteen years if not longer. For the purpose of the NSCR cost analyses presented here, a 15-year life of the NSCR system was assumed.

In addition, a lower interest rate than 7% is assumed in determining annualized costs of controls for this report. As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

The table below shows the cost effectiveness of NSCR and an AFRC achieving 94% NOx reduction efficiency and operating at 2,000 hours per year and 8,000 hours per year, based on these cost equations from EPA's 2010 RICE NESHAP, adjusted to reflect a 4.7% interest rate and 15-year life of controls.

Note that lower NOx emission limits may be possible that reflect a higher NOx removal efficiency than the 94% assumed in the table below and the costs of employing NSCR to meet these lower limits will be even more cost effective than what is shown here.

Table 53. Cost Effectiveness to Reduce NOx Emissions from 4SRB RICE with NSCR and an AFRC, Based on EPA RICE NESHAP Cost Equations for Existing Stationary RICE[740]

UNIT	SIZE, hp	ANNUALIZED COSTS OF NSCR AND AFRC, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2009$
801	418	$6,544	$499/ton	$125/ton
802	418	$6,544	$499/ton	$125/ton

We did not escalate these costs to 2019 dollars. The Chemical Engineering Plant Cost Index (CEPCI) has been used extensively by EPA for escalating costs, but EPA states that using the CEPCI indices to escalate costs over a period longer than five years can lead to inaccuracies in

[738] *See* Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for RICE Source Category, circa 2008 [hereinafter referred to as "CDPHE RP for RICE"], at 8, *available at*: https://www.colorado.gov/pacific/sites/default/files/AP_PO_Reciprocating-Internal-Combustion-Engine-RICE-engines_0.pdf.

[739] *See* EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 80, *available at*: https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.

[740] *See* Memo from E^{C}/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010). Annualized costs of control were calculated using a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 4.7% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and a 94% NOx removal efficiency.

price estimation.[741] Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. As an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. However, even today's costs for NSCR are assumed to be very cost effective given that the cost effectiveness based on 2009$ is on the order of $100/ton.

XXII. Durango Midstream - Empire Abo Gas Plant

The Empire Abo Gas Plant is a natural gas processing and gas sweetening plan located in Eddy County, New Mexico, operated by Durango Midstream. NMED did not request a four-factor analysis for this facility, but the source does have a Q/d value of 24.2 based on 2014 emissions and it is 68.9 kilometers from Carlsbad Caverns National Park according to NMED's Emission Data Analysis Tool. The plant is permitted to operate under two operating scenarios: 1) a gas sweetening and processing plant, and 2) a compressor station that receives gas at low pressure and routes it to the Maljamar Gas Plant for processing.[742] A review of data on NMED's Emissions Analysis Tool shows that the plant has varying emissions, with the last three years (2017-2019) being much lower emissions than in the past. For the 2016 year that most facilities used as a baseline, the plant emitted 271.1 tons of SO2. However, currently, the plant emitted 72 tons in 2019 and only 19 tons of SO2. In the 2012 to 2015 timeframe, the plant had about 200 tpy of NOx emissions and approximately 450-850 tpy of SO2 emissions. The state should request information from Durango Midstream as to the planned operation of the plant (whether it will be primarily as a gas sweetening plant or a compressor station) in 2028 to determine which sources to focus on for control.

Of all of the emission limits identified in the Title V permit, the SRU/Incinerator is allowed the highest level of emissions of 565 tpy.[743] Based on the discussion in Section XXIII below, NMED should thus require the company to evaluate an AGI well and/or an acid gas scrubber to add after the tail gas incinerator to remove SO2 when the SRU is down for maintenance.

XXIII. Comments on Pollution Control Evaluations for Amine Units/Acid Gas Flares at Gas Sweetening Plants

NMED requested four-factor analyses of controls for several amine units at New Mexico gas processing plants. Amine treating units are used to remove hydrogen sulfide (H2S) and carbon dioxide (CO2) from natural gas. Plants that remove H2S are referred to as gas sweetening plants. Amines such as Monoethanolamine (MEA), Diglycolamine (DGA), Diethanolamine (DEA) and Methyldiethanolamine (MDEA) can form salts with H2S and CO2 in an aqueous solution.

Targa's four-factor submittal for the Saunders gas plant describes and amine unit as follows:

[741] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.
[742] 6/30/2017 Title V Permit No. P146-R3 for Empire Abo Gas Plant.
[743] *Id.*at A11.

> An amine treating unit operates by feeding the inlet gas stream into the bottom of a contactor and simultaneously feeding a lean amine solution at the top of the contactor. The two streams interact in counter flow, resulting in CO2 and H2S being stripped from the natural gas stream. The lean amine solution must be kept at a higher temperature than the gas feeding into the contactor, or condensation of heavier hydrocarbons could occur. Trays or packing in the contactor provide a place for the lean amine solution to interact with the inlet gas stream. The natural gas leaving the contactor will be "sweet gas."
>
> The rich amine leaving the contactor is usually sent to a flash tank which reduces the pressure of the stream and causes dissolved hydrocarbons to flash off. The rich amine will then pass through a heat exchanger and enter a solvent regenerator. The heated vapor generated at the bottom of the regenerator flows upward through the trays or packing where it comes in contact with the rich amine and removes the acid gases from the amine. The lean amine is then cooled and reenters the first contactor to start the process over. The acid gas that is dissolved in the vapor is then sent to a control device such as a sulfur recover unit (SRU) with a tail gas incinerator, a flare, or an acid gas injection (AGI) well.

November 2019 Four-Factor Analysis for Saunders Gas Plant at 2-8 to 2-9.

The acid gas exiting the amine unit is essentially composed of H2S and CO2. While the percentage of H2S and CO2 can vary depending on the sulfur content of the natural gas, as one example, a gas amine unit in Texas in the Permian Basin is composed of approximately 45% H2H and 54% CO2.[744] According to EPA's AP-42 Emission Factor documentation, emissions from gas sweetening units only result when gas is flared or incinerated and the major pollutant of concern from such flaring or incineration is SO2.[745] When the acid gas stream is flared rather than injected into the geologic strata or controlled with an SRU, all or most of the H2S is converted to SO2. While flaring may be a control for H2S in the acid gas stream, it is a cause of SO2 emissions and does not control SO2.

The typical controls for amine units are acid gas injection (AGI) well or a sulfur recovery unit (SRU). An AGI well should result in no emissions because the acid gas stream is injected into the geologic strata. However, if there are any malfunctions in the equipment that pumps the acid gas stream into the AGI, then air emissions can result. An SRU converts hydrogen sulfide to element sulfur. The most commonly applied method is the Claus method, which can typically recover 95-97% of the hydrogen sulfide feed stream.[746] According to EPA, older SRUs or very

[744] *See* Oil and Gas Docket No. 08-0289658, Application of James Lake Midstream, LLC, available for download at https://www.rrc.state.tx.us/hearings/dockets/oil-gas-proposals-for-decision-and-orders/index-for-336/.
[745] EPA, AP-42, Section 5.3 Natural Gas Processing at 5.3-3.
[746] EPA, AP-42, Sulfur Recovery at 8.13-1.

small Claus plants producing less than 22 tons of sulfur per day have varying sulfur recovery efficiencies.[747] The following table lists those amine units for which NMED requested four-factor analyses for the control of SO2.

Table 54. List of Facility Amine Units (or Acid Gas Flares) For Which NMED Requested Four-Factor Analysis of Controls and Potential to Emit (PTE) SO2 as Reported in Company Analysis

Facility	Amine Unit	Existing Controls	PTE SO2 tpy	PTE SO2 lb/hr
Jal No. 3	Unit 9S (Thermal Oxidizer)	SRU and AGI well	1,205.9	275.3
DCP-Eunice Gas Plant	Unit 31	SRU	257.2	9,368.2
Targa-Eunice Gas Plant	Unit AM-01/F-01	AGI well	776.5	5,176.6
Targa-Monument Gas Plant	Unit AM-01/F-03	AGI well	872.6	5,817.5
Targa – Saunders Gas Plant	Unit A-01/I-01	SRU with tail gas incinerator	1,397.0	316.7
DCP-Artesia Gas Plant	Amine-C Unit 23 (Acid Gas Flare)	AGI well	328.2	4918.4
Davis Gas Processing - Denton Gas Plant	Unit 005 (amine regeneration still and reboiler) and Unit 007 (acid gas flare)	None	1,195.9	312.5
Oxy-Indian Basin Gas Plant	Unit AMINE -1 & SELEXOL	AGI	Not indicated	Not Indicated

It must be noted that there are facilities listed in the above table that did not specifically list amine units but that otherwise did list startup, shutdown, and maintenance (SSM) emissions as triggering the need for a four-factor analysis due to SO2 emissions. For those facilities listed in the above table (DCP Eunice Gas Plant and DCP Artesia Gas Plant), the units have gas sweetening plants and the SO2 emissions from SSM are from flaring of the acid gases. Yet, those companies' four-factor analyses claimed they did not need to evaluate controls for SSM emissions that occur during "non-steady state" operations.[748] Flaring of the acid gas stream at units with amine units appear to, unfortunately, be part of the normal operations of the unit even though due to SSM, and there are control options available to reduce SO2 emissions from flaring – by reducing flaring via redundant acid gas steam control options (second AGI well, or

[747] *Id.* at 8.13-3.

[748] *See*, e.g., November 2019 Four-Factor Analysis for DCP Eunice Gas Plant at 1-2 and November 2019 Four-Factor Analysis for DCP Artesia Gas Plant at 1-2.

redundant compressor at AGI well, or SRU plus AGI well) or by replacing a flare with an incinerator and acid gas scrubber to be used when the primary acid gas control for the amine unit is not functioning. Thus, NMED must not allow facilities with significant SO2 emissions due to SSM to be exempt from a four-factor analysis of controls.

The following provides a discussion of controls for SO2 emissions at gas sweetening plants in the context of reviewing and commenting on the four-factor submittals for the facilities listed in the above table.

A. Amine Units with No Acid Gas Controls – Denton Gas Plant

There is one amine unit listed in the above table which apparently has no H2S controls – the Davis Gas Processing Denton Gas Plant. Although the Denton Gas Plant used 2017-2018 SO2 emissions as baseline emissions for its cost effectiveness analysis, the plant's two-year average SO2 emissions have varied from 713.00 tpy (2017-2018 average) to 1,061.27 tpy over the past ten years.[749] Davis Gas Processing states that the sulfur recovery process (both the Claus process and another processed called LO-CAT) were eliminated from further consideration because of concerns of the level of control achievable with variable flowrates and H2S concentrations, which the company claims are common at Denton, and apparently because of the low throughput rate that would apply to an SRU at the Denton amine unit.[750] While a properly designed, operated, and maintained acid gas injection well would achieve a higher level of SO2 control (SO2 removal efficiency should be 100% with an AGI well), we note that NMED has requested some companies to analyze installing an AGI well in addition to having a sulfur recovery unit.[751] Such duplicative controls should be considered, even for units with AGI wells. Although an AGI well in theory should provide 100% control of SO2, problems with the equipment to compress and pump the acid gas steam into the AGI well can occur – or sometimes even with the AGI well. For example, Targa explained that its Monument AGI well "failed an OCD required pressure test on July 27, 2016" and the well had to be shut down August 8th and ultimately was abandoned, resulting in significant flaring of acid gas until the new well became operational in March 2017.[752] This flaring resulted in approximately 2,000 tons of SO2[753] from a pollution control that should have 100% SO2 reduction efficiency. While this AGI well malfunction may have been unique, there clearly are also problems with AGI compressors because other New Mexico companies have installed, or are in the process of installing, redundant compressors.[754] Yet, redundant compressors are not necessarily enough to prevent significant SO2 emissions from flaring that may occur during upsets or maintenance. NMED should ask each company with gas sweetening plants, including the Denton Gas Plant, to evaluate the cost of redundant SO2 pollution controls. One option is to install an SRU if the

[749] November 2019 Denton Gas Plant Four-Factor Analysis at 2-2.
[750] *Id.* at 2-4.
[751] *See* Targa's February 2020 Four-Factor Addendum for the Eunice Gas Plant at pdf page 10.
[752] *Id.*at pdf page 9.
[753] *Id.*
[754] *Id.* at pdf page 10. Targa states that it installed redundant compression at the Monument AGI well as a result of an AQB enforcement case. Targa also installed redundant compression at the Eunice Gas Processing Plant.

facility already has an AGI well, to be used when the AGI well cannot be used for control. Another option is to have the gas routed to an incinerator with an add-on acid gas scrubber, when the AGI well is not functioning.[755] For those facilities that have SRUs to control SO2 from amine units or that have no SO2 controls such as the Denton Gas Plant, adding an AGI well as a duplicative control should be evaluated first.

The four-factor analysis for the Denton Gas Plant evaluated the costs of installing an AGI well. While the Denton analysis used a 5.25% interest rate and a 20-year life as well as the lowest 2-year baseline of all of the past 10 years of SO2 emissions, the company's cost effectiveness analysis shows that an AGI well would be quite cost effective at $1,014/ton of SO2 removed.[756] Davis Gas Processing likely overstated the capital costs of an AGI well, by adding 25% to the purchased equipment costs as well as using EPA's Control Cost Manual's percentage of purchased equipment costs for foundations and supports, handling and erection, etc.[757] As the company notes in its four-factor analysis, the use of AGI for the disposal of acid gas "is becoming increasingly common…"[758] Thus, rather than adding a 25% contingency factor to the purchased equipment cost and then adding EPA's Control Cost Manual estimates (which are a percentage of the purchased equipment costs) for installation of an AGI, the company could have obtained a reliable estimate of the cost of AGI well installation. With respect to operating expenses, David Gas Processing's analysis assumed a cost per kW hour of $0.11 which appears to be the cost for residential service in New Mexico.[759] The electricity cost for an industrial user is generally much lower than a residential user. EPA estimates the cost for electricity in its SCR cost spreadsheet of $0.0676/kWh. A web search for average electricity cost in New Mexico for industrial use shows a cost of $0.0583/kWh.[760] Thus, annual electricity costs for the electric compressors for an AGI well in New Mexico should be in the range of $41,893 to $48,575 rather than the $79,043 assumed for the Denton Gas Plant. Further, this cost reflects electricity use when the compressors are used at maximum capacity for all hours of the year, so this is a worst case annual operating cost. The company's assumed cost for electricity has a significant impact on the cost effectiveness of an AGI well. When just the cost for electricity is revised to be $0.0583/kWh, the cost effectiveness of an AGI well at the Denton Gas Plant reduced from $1,014/ton to $663/ton. If the interest rate is lowered to a more reasonable 4.7% for the reasons discussed in this report and the life of an AGI well is increased to 25 years which seems reasonable given the life of gas sweetening plants like Denton, the cost effectiveness of an AGI well further reduces to $574/ton. Moreover, if one removes the 25% contingency factor that Davis Gas Processing applied to its estimate of equipment costs, the cost effectiveness of AGI to reduce SO2 would be $481/ton. Clearly, installation of an AGI well is very cost effective for the Denton Gas Plant.

[755] *See* March 2020 NPCA Oil and Gas Four-Factor Report at 148-154.
[756] November 2019 Denton Gas Plant Four-Factor Analysis at 3-4.
[757] *Id.*
[758] *Id.* at 2-5.
[759] *See*, e.g., https://www.electricitylocal.com/states/new-mexico/.
[760] https://www.electricitylocal.com/states/new-mexico/

B. Amine Units with SRUs – DCP Eunice Gas Plant and Targa Saunders Gas Plant

With respect to the DCP Eunice Gas Plant which has an SRU, DCP's four-factor analysis claims that the area is not suitable for an AGI well[761] despite being near to the Targa Monument Gas Plant which also has an AGI well. It appears that the plants are roughly 10 miles apart. NMED should request more information from DCP as to why it claims an AGI well is not viable for its Eunice Gas Plant. Not only could this provide more information to enable NMED to thoroughly consider the Targa Monument Plant's SO2 controls for its amine plant, but it is needed to justify DCP's claims that an AGI well is not feasible for its location especially given how cost effective an AGI well can be based on the revised Denton Gas Plant analysis discussed above. DCP states that AGI wells typically include a second redundant AGI well.[762] The fact that such redundancy is required for SO2 controls when an AGI well is used for control argues for redundancy in controls when an SRU (which is not nearly as efficient in SO2 reduction as a properly operating AGI well) is used for SO2 control. Use of an incinerator with an add-on acid gas scrubber as a redundant control for those amine units with SRUs should thus be evaluated as an additional SO2 control. This could be used downstream of the SRU to improve SO2 removal efficiency when the SRU is operating and could also be used when the SRU is down for maintenance or upsets. These types of duplicative control have been used in oil refineries and thus are a viable control option for a natural gas processing plant as well.[763] NMED should thus require DCP to evaluate this control option. In addition, NMED should ask DCP to report on its SO2 removal efficiency of its current SRU and to quantify its actual SO2 emissions from flaring the acid gas stream when the SRU is down for maintenance or upsets. As part of its four-factor analysis, NMED must evaluate the level of SO2 control currently being achieved at the gas sweetening plant and ensure that all available options for improving that level of control are evaluated. The Targa Saunders Gas Plant utilizes a "Select-Tox Single State Claus bed with a tail gas incinerator" as a control for the amine unit, with an acid gas flare when the SRU is down for maintenance.[764] Targa considered an AGI well, but claimed it could not install an AGI well without plugging/cementing some of the numerous other wells in the area because acid gas could vent from any unplugged wells.[765] NMED should request more information on the documentation collected by Targa to support this claim. Targa did not evaluate any other controls to reduce SO2 emissions from its amine unit after finding an AGI well was not feasible for the Saunders plant.[766] NMED should require Targa to evaluate the option of adding an acid gas scrubber to its tail gas incinerator and to operate the incinerator and scrubber when the SRU is not available due to maintenance or upsets. This would enable the continued control of SO2 even during SRU downtime, rather than flaring which does not control SO2 emissions at all. In addition, NMED should ask DCP to report on its SO2 removal efficiency of its current SRU and

[761] November 2019 Four-Factor Analysis for DCP Operating Company's Eunice Gas Plant at 2-8 to 2-9.
[762] *Id.*
[763] *See*, e.g., July 2006, Meyer, Steven F., Christina Kulczycki, Ed Juno, and Nick Watts, Improving Sulphur recovery units, Digited Refining, available at https://www.digitalrefining.com/article/1000244/improving-sulphur-recovery-units#.XvJCRudME2w.
[764] November 2019 Four-Factor Analysis for Targa Saunders Gas Plant at 2-9.
[765] *Id.* at 2-10.
[766] *Id.* at 3-3.

to quantify its actual SO2 emissions from flaring the acid gas stream when the SRU is down for maintenance or upsets. As part of its four-factor analysis, DCP must evaluate the level of SO2 control currently being achieved at the gas sweetening plant and ensure that all available options for improving that level of control are evaluated.

C. Amine Units with AGI Wells – Targa Eunice Gas Plant, Targa Monument Gas Plant, DCP Artesia Gas Plant, and Oxy Indian Basin Gas Plant

As indicated above, the Targa Monument Gas Plant flared its acid gas stream for several months in 2016 -2017 due to a failed AGI well after five years of service.[767] This facility provides a pertinent example of how - even an amine unit controlled by an AGI well, which should theoretically eliminate 100% of the potential SO2 emissions - acid gas injection wells need backup and/or redundancy to ensure control of SO2. Indeed, NMED must require all amine plants with AGI wells in the table above to consider duplicative controls for removal of sulfur from the acid gas stream or prevention of SO2 emissions from flaring. Options to consider are 1) a duplicative AGI well, 2) an incinerator and add-on acid gas scrubber or an SRU for when the acid gas stream cannot be routed to the AGI well, and 3) duplicative equipment for ensuring the acid gas is continually injected into the acid gas well, such as a redundant electric compressor. The four-factor analysis submitted by Targa for the Eunice Gas Plant claims the AGI well is in the process of having redundant electric compression added to the AGI well to further reduce SO2 emissions during SSM.[768] Targa did not evaluate any other controls. Similarly, Targa stated that it is adding redundant electric compression to the Monument AGI well, and the company did not evaluate any other controls for its amine plant.[769] While having redundant compression will help to ensure that the acid gas stream is not flared due to the AGI well compressor malfunctioning or being down for maintenance, NMED should ask Targa to evaluate the costs of adding an SRU or adding an incinerator and acid gas scrubber for further redundancy in its SO2 control systems. With respect to the Monument Gas Plant AGI well, given the statements made by DCP in its four-factor analysis for the Eunice Gas Plant that the area is not well-suited for acid gas injection and given the Monument plant's proximity to the DCP Eunice Gas Plant, NMED must determine if the failure of the Monument AGI well is due to any of the reasons that DCP indicated in its Eunice Gas Plant four-factor analysis for an AGI well not being viable in the region. Further, NMED should collect and present data on the last five years of how much SO2 was emitted due to flaring of the acid gas stream at Monument due to upsets at the AGI well's compressors or other causes of flaring of the acid gas stream. Given the failure of the Monument AGI well after five years and the resulting 2,000 tons of SO2 emitted, it seems that redundant controls such as an SRU or an incinerator with acid gas scrubber must be considered as a duplicative SO2 control for the amine unit at the Monument Gas Plant. NMED should also require an evaluation of such controls for the Targa Eunice Gas Plant.

[767] *See* Targa's February 2020 Four-Factor Addendum for the Eunice Gas Plant at pdf page 9.
[768] November 2019 Four-Factor Submittal for Targa Eunice Gas Plant at 2-6.
[769] November 2019 Four-Factor Submittal for Targa Monument Gas Plant at 2-1.

In the Oxy Indian Basin Gas Plant four-factor submittal, Oxy only evaluated one control – a redundant compressor for the AGI.[770] Oxy's submittal indicated a cost effectiveness of $27,600/ton of SO2 reduced due to an estimated cost for electric compression of $11 million.[771] The company assumed baseline emissions from 2016 of NMED of 41.92 tpy and assumed a redundant compressor would reduce those emissions by 90%. NMED should ensure that the company is using realistic baseline emissions due to flaring of the acid gas stream. If 2016 was an exceptionally good year (not much flaring), but prior years had much higher emissions, cost effectiveness should be based on a longer term average of emissions. If baseline emissions were 200 tpy of SO2 from flaring, and with a more appropriate interest rate and lifetime of electric compressor of 4.7% and 25 years (instead of 5.50% and 20 years), the cost effectiveness of a redundant compressor would reduce to $4,873/ton. If the plant emitted 500 tpy, the cost effectiveness would be about $2,000/ton. Thus, it is imperative that NMED ensure that the company uses a realistic SO2 baseline for evaluating redundant controls such as duplicative compressor for its acid gas injection well. NMED did ask Oxy to consider adding a second control to its AGI system to reduce flaring emissions, such as the LO-CAT sulfur recovery technology.[772] The company indicates that it had an SRU that has been shut down due to poor reliability.[773] Given that the SRU already exists on site, NMED should ask the company to evaluate the cost for bringing the SRU back online to use only as a backup to the AGI well. That could be a very cost effective way to ensure redundancy in the SO2 removal systems at the Indian Basin Gas Plant.

DCP did not evaluate any controls for its amine plant at the Artesia Gas Plant. The company's four-factor analysis only listed emissions from flaring and stated that, based on NMED's September 23, 2019 guidance, it did not need to evaluate controls from flaring.[774] Yet, it listed acid gas flaring (Unit 23) as a significant source of SO2 emissions.[775] A review of the Title V permit for the facility shows that the facility has an amine plant and an AGI well.[776] NMED must request that the company provide information on its actual SO2 emissions from flaring the acid gas stream from its amine unit. Further, NMED must request DCP to evaluate duplicative controls and/or redundant AGI well compression.

Moreover, as part of evaluating SO2 control options for any gas processing plant, NMED should collect information on the time periods, causes, and SO2 emissions of acid gas stream flaring at the plant to determine if additional maintenance requirements should be imposed with reporting and recordkeeping to NMED.

[770] November 2019 Four-Factor Analysis for Indian Basin Gas Plant at 2-5, 3-2, and Appendix B.
[771] *Id.* at Appendix B.
[772] February 2020 Four-Factor Addendum for Oxy Indian Basin Gas Plant at pdf page 2.
[773] *Id.*
[774] November 2019 Four-Factor Submittal for DCP Artesia Gas Plant at 1-2.
[775] *Id.*
[776] 6/27/17 Title V Permit No. P095-R3 for DCP Artesia Gas Plant at A8.

D. Units with SRU and AGI Well – Jal No. 3

The four-factor analysis for the Jal No. 3 amine plant states that the acid gas from its amine units is sent to a sulfur recovery unit which scrubs the H2S at 92% efficiency and that the leftover H2S from the SRU is sent to the thermal oxidizer to be combusted.[777] During downtime of the SRU and/or thermal oxidizer, the acid gas is sent to the AGI wells, and during AGI well downtime, the acid gas is sent to the SRU and thermal oxidizer.[778] The company's four-factor analysis states that "[t]hese existing controls are the best known technologies for controlling acid gas and, to our knowledge, there are no other technically feasible control options to further reduce SO2 emissions from the thermal oxidizer."[779] While this suite of controls does reflect the type of duplicity in controls that is necessary for addressing SO2 emissions as gas sweetening plants, it does seem that there are additional control options that the company should have considered. Despite these duplicative controls, the facility emits significant quantities of SO2. According to date on NMED's Emissions Analysis Tool, the Jal No. 3 plant emitted almost 2,000 tons of SO2 in 2016, the year NMED is apparently using as the baseline year for company four-factor analyses. While SO2 emissions have decreased since then, annual SO2 emissions have varied from 207 tons in 2017 to 1,444 tons in 2018 to 587 tons in 2019. Presumably these emissions are all from the Unit 9S thermal oxidizer, as that appears to be the primary source of SO2 emissions based on a review of the Title V permit.

Two additional control options should have been considered for the Jal No. 3 amine unit/thermal oxidizer: 1) Routing the cleaned acid gas stream from the SRU to the AGI well during normal operation of the SRU, which would improve SO2 removal efficiency from 92% to 100% (when the AGI well was operating and not down for maintenance or upset). Under this control option, the plant should continue to route the acid gas stream directly to the AGI wells during SRU downtime; or 2) Revise the configuration to inject the acid gas stream from the amine units to AGI wells, but route the acid gas stream to the SRU/thermal oxidizer during AGI well downtime to at least achieve 92% H2S removal before combusting the acid gas. It seems like either of these two options could provide for significant additional control of SO2 from the amine units at the Jal No. 3 gas plant. NMED must require ETC Texas Pipeline to evaluate these available control options at Jal No. 3 (given that the SRU and the AGI wells already exist at the facility) to control the SO2 emissions from the facility which can be quite significant despite the plant's duplicative controls.

E. Summary

In summary, because the flaring or incineration of acid gas streams from amine units at gas sweetening plants can be such a significant source of SO2, NMED must ensure a thorough evaluation of control options for such sources. NMED should not consider such sources of emissions to be non-steady state and exempt from the four-factor review of controls, because

[777] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at 7.
[778] *Id.*
[779] *Id.* at 8.

such emissions of SO2 can be very high and can be addressed through duplicative or redundant controls. NMED must also ensure that reasonable evaluations of baseline emissions are used in evaluating the cost effectiveness of controls, in that the baseline emissions must realistically depict emissions from acid gas incineration at a facility.

New Mexico Environment Department



Draft Regional Haze Plan Informational Webinar

NMED Regional Haze Planning Team
September 9, 2024 5:30pm
September 10, 2024 10:00am

Agenda

- Introductions
- Background
- Overview of Draft Plan
  - Selected Sources
  - Control Evaluations
  - Results of Analysis
- New Rule 20.2.68 NMAC
- Navigating the Draft Plan
- Engagement Opportunities
- Discussion

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NMED Regional Haze Planning Website:

https://www.env.nm.gov/air-quality/reg-haze/

Background

- Haze is caused by tiny particles in the air that absorb and scatter light
- Haze-forming pollutants come from natural and manmade sources. Manmade sources can include motor vehicles, fuel combustion, and manufacturing operations.
- Haze reduces visibility, obscuring scenic vistas
- Haze-forming pollutants can also impact human health

Background

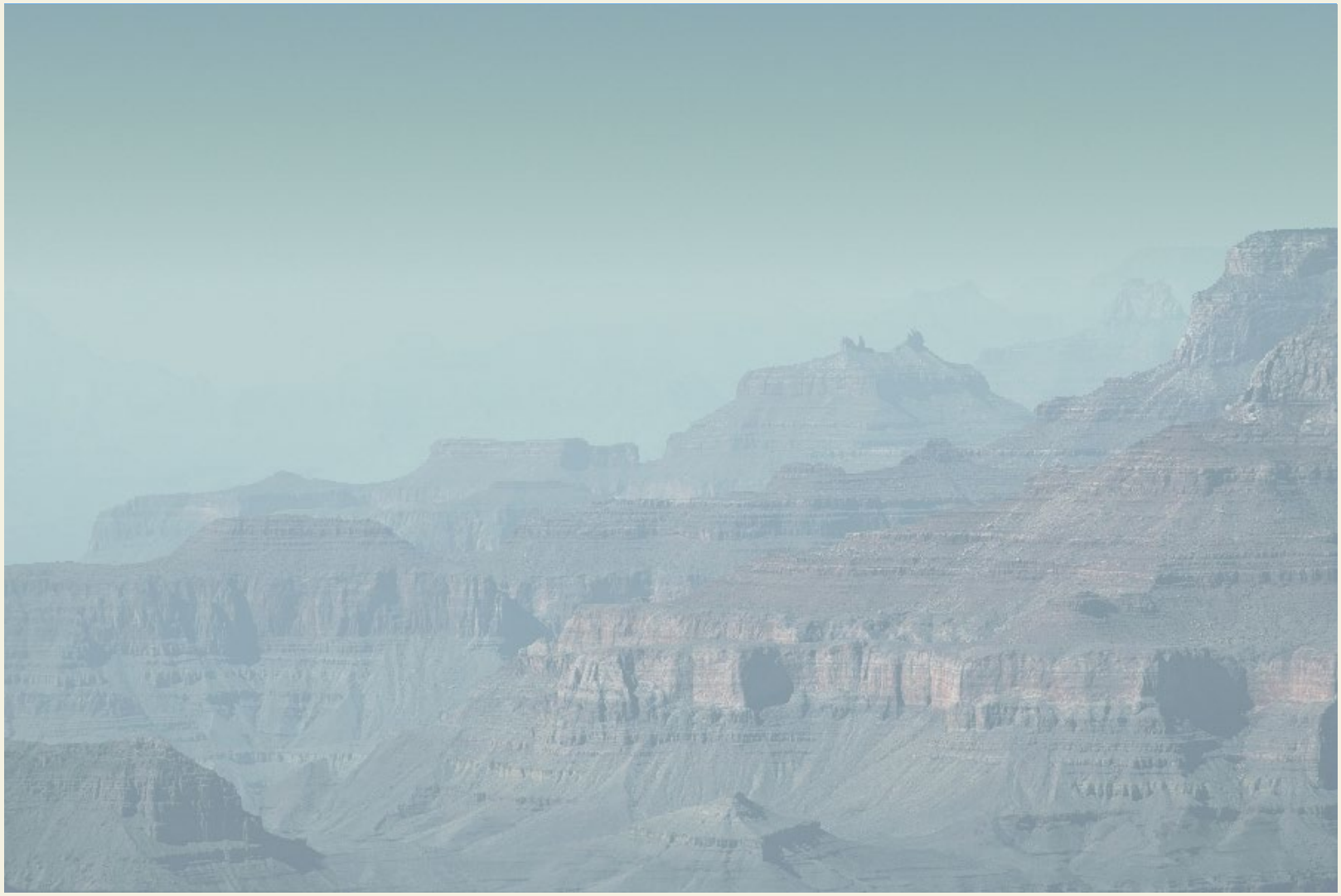


Photo Credit: WESTAR-WRAP

Background

- The Regional Haze Rule calls for state and federal agencies to work together to improve visibility in 156 national parks and wilderness areas across the United States.
- States are required to develop plans to reduce the pollution that causes visibility impairment in these protected areas; these plans must be revised every 10 years
- States coordinate and consult with EPA, other states, Tribal governments, the general public, and others when developing their Regional Haze plans

Background



Source: https://www.epa.gov/visibility/regional-haze-program

Overview of Draft Plan

SELECTED SOURCES

Selected Sources

- NMED used a screening process to select 23 facilities for an analysis of potential control measures
- NMED evaluated 133 individual emissions units at those facilities based on additional screening criteria
- The goal of NMED's screening process was to focus efforts on higher emitting units at the largest sources of air pollution that are most likely to affect visibility in protected areas based on their emissions and proximity to those areas

Selected Sources



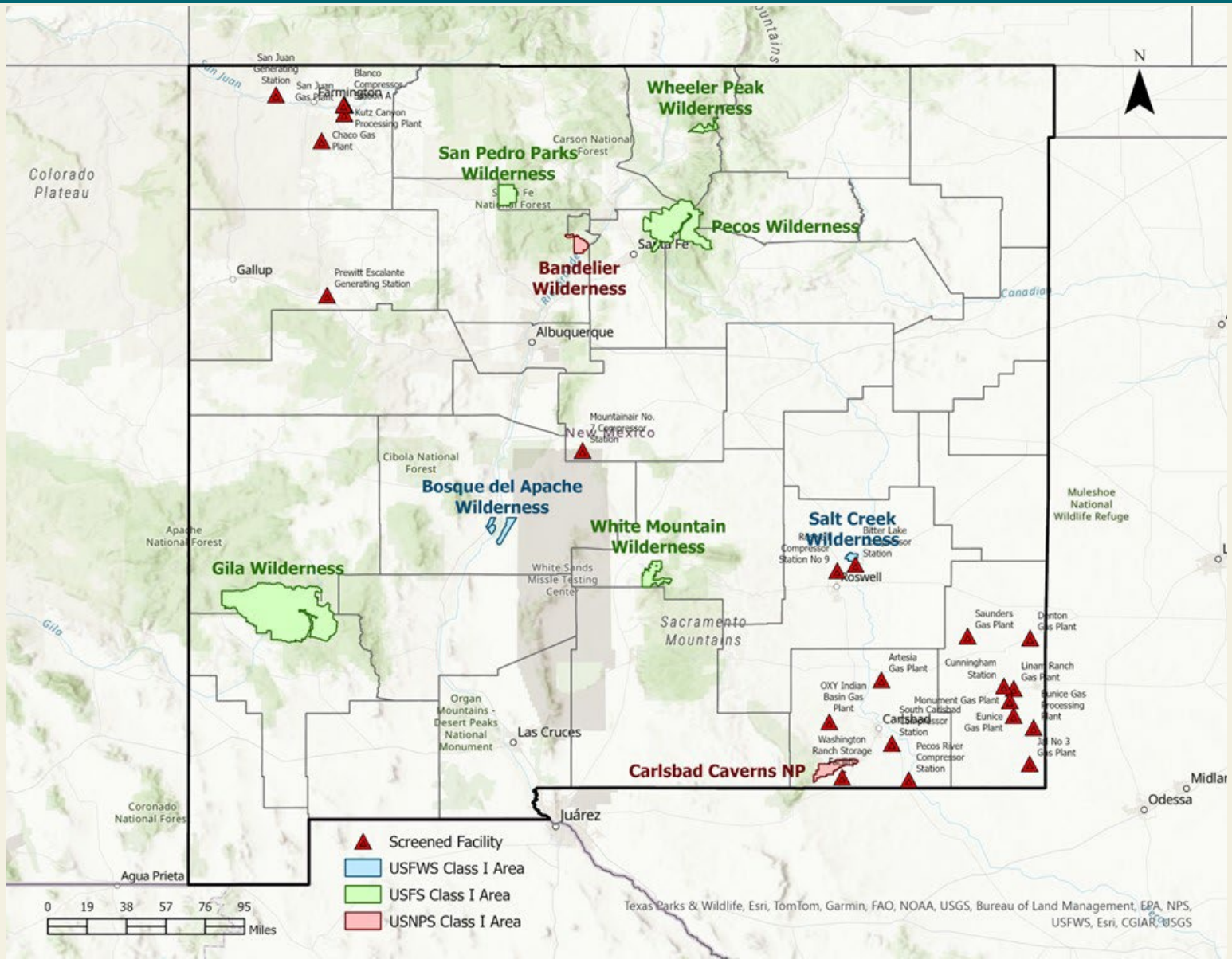
Selected Sources







Selected Sources



Overview of Draft Plan

CONTROL EVALUATIONS

Control Evaluations

- Identify all feasible control options for each unit
- For each feasible option:
  - Determine cost to implement ($)
  - Estimate emissions reductions (tons/year)
  - Calculate cost effectiveness ($/ton)
- Determine appropriate cost threshold
- Select required controls

Overview of Draft Plan

RESULTS OF ANALYSIS

Results of Analysis

- New Controls on 54 Emissions Units
- Permanent Retirement of 34 Emissions Units
- Measures to Ensure Continued Use of In-Place Controls on 11 Emissions Units
- Significant Reductions in Emissions of Pollutants that Contribute to Visibility Impairment
  - Nitrogen Oxides > 18,000 tons/year
  - Sulfur Dioxide > 5,000 tons/year

New Rule 20.2.68 NMAC

- The emission limitations and other measures in the draft plan must be enforceable by EPA
- To ensure federal enforceability, NMED developed a new companion rule, 20.2.68 NMAC – Regional Haze Requirements
- The new rule's requirements are identical to those in the draft plan
- The new rule also includes monitoring, recordkeeping, and reporting requirements mirroring existing requirements

Navigating Draft Plan

- Table of Contents
  - Headings, Figures, and Tables are all Hyperlinked and Bookmarked
- List of Abbreviations
- Executive Summary

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Engagement Opportunities

- Informal Comment Period
  - Last day for informal comments is 9/20/2024
- Formal Notice and Comment Period
  - Anticipate starting early October
  - https://www.env.nm.gov/public-notices/
  - https://public.govdelivery.com/accounts/NMED/subscriber/new
- Public Hearing
  - The public may participate in the hearing
  - Dates TBD; Anticipate early to mid-December 2024

Discussion

Questions or Comments?

E.7 Public Review Period Comments

NMED made available a public review draft SIP revision and draft new Regional Haze rule on August 26, 2024. Comments received during the public review period are provided below. The following documents are included in this section (in reading order):

- Enterprise Field Services Request for Extension of Comment Period (9/17/2024)
- PNM Comments (9/19/2024)
- Sierra Club Comments (9/19/2024)
- Wild Earth Guardians Comments (9/20/2024)
- Enterprise Field Services Comments (9/20/2024)
- El Paso Natural Gas Company Comments (9/20/2024)
- Phillips 66 (DCP) Comments (9/20/2024)
- U.S. National Park Service Comments (9/20/2024)
- Western Environmental Law Center Comments (9/20/2024)
- El Paso Natural Gas Company Presentation Meeting with NMED on Comments Submitted (10/22/2024)

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September 17, 2024

Via Electronic Mail
Filed in New Mexico Environment Department, Air Quality Bureau

Mr. Mark Jones
New Mexico Environment Department, Air Quality Bureau
525 Camino de Los Marquez, Suite 1
Santa Fe, NM 87505

Re: Request for Extension of Comment Period

Dear Mr. Jones:

On August 26, 2024, the New Mexico Environment Department ("NMED") published a draft state implementation plan and proposed companion rule ("Draft SIP") to address the Clean Air Act's requirements for the second planning period of the regional haze program. NMED established an abbreviated comment period of just 25 days, with a deadline of September 20, 2024. Enterprise Field Services, LLC ("Enterprise") requests that NMED extend this deadline by 30 days, until October 20, 2024.

Three Enterprise facilities—the Blanco C & D Compressor Station, the Chaco Gas Plant, and the South Carlsbad Compressor Station—would be subject to the Draft SIP's proposed requirements. As such, the Draft SIP's consistency with the law and whether it is supported by sound technical analysis are of great importance to Enterprise.

Additional time is needed to prepare comprehensive comments on such a significant and wide-ranging set of proposed new regulatory requirements. To that end, Enterprise is diligently working to develop new technical analyses to address the state's proposal. Despite our best efforts, completing that labor-intensive work by the existing September deadline will be incredibly challenging. Because this analysis is crucial to the record, Enterprise believes an extension is warranted.

Enterprise recognizes that NMED had not intended to extend the comment period of the Draft SIP and that the Department is seeking to finalize the Draft SIP consistent with deadlines for action by the U.S. Environmental Protection Agency on the New Mexico regional haze SIP. Nevertheless, Enterprise has identified serious flaws in the Draft SIP and believes NMED must take the necessary time to correct these deficiencies and to respond to substantive comments, including the information Enterprise is working to develop. To that end, if NMED is unable to formally extend the comment period, Enterprise asks that NMED commit to considering late-filed

information that Enterprise is working to develop if that information cannot be finalized by the current comment deadline.

Thank you for your consideration of this request. If you have any questions or wish to discuss how to ensure information Enterprise is developing is included in the record and considered in these proceedings, we welcome further discussion.

Sincerely,



Aaron Flynn
Counsel to Enterprise Field Services, LLC

Claudette Horn

Comment letter has been uploaded.

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Albuquerque, NM 87107
www.pnm.com

September 19, 2024

Eric Peters, Control Strategies Manager
Mark Jones, Planner
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NMED Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico, 87505-1816

RE: New Mexico Regional Haze SIP for the Second Planning Period

Public Service Company of New Mexico ("PNM") appreciates the opportunity to comment on the regional haze state implementation plan ("SIP") prepared by the New Mexico Environment Department ("NMED") for the second planning period. Overall, PNM supports the SIP because it satisfies all of the mandatory requirements of the Clean Air Act visibility provisions and regulations, generally follows EPA's preferred regional haze policies, and includes a reasonable selection of emission control measures from a wide range of sources. Accordingly, PNM supports submission of the SIP to EPA for approval and also offers the following comments for consideration.

First, PNM supports NMED's decision to determine and rely upon an adjusted uniform rate of progress—the "glidepath" toward the 2064 goal of eliminating anthropogenic visibility impairment—by taking into account international emissions and wildland prescribed fires. Because these sources of visibility impairment cannot be eliminated by any action taken by NMED, PNM agrees that the ultimate goal of the program should be adjusted to recognize the uncontrollable nature of those emission sources. With the adjusted glidepath, NMED will be able to focus its efforts more clearly on reducing the controllable sources' anthropogenic emissions subject to its jurisdiction. This approach is fully consistent with EPA's regulations and guidance, and PNM expects EPA will approve it as a reasonable component of the SIP.

Second, PNM supports NMED's recognition of the fact that, even with the adjusted glidepath, a more robust demonstration of reasonable progress was needed for Salt Creek Wilderness Area because the modeling performed by the Western Regional Air Partnership ("WRAP") projected the area may be above the adjusted glidepath in 2028. Although visibility is continuing to improve in the area, and the area is projected to be above the glidepath by only a slim margin, PNM agrees further analysis was required by EPA's regional haze rule. However, PNM also agrees with the conclusions drawn from that additional analysis, confirming that all reasonable measures have been taken to improve visibility in the area, and that the modeling projection likely does not consider other emission reductions that will help ensure visibility continues to improve at the Salt Creek Wilderness Area.

Third, PNM supports the methodology NMED applied in identifying the sources to review for additional control measures and the control measures selected for those sources to include in the long-term strategy for the second round SIP. NMED's conservative screening process appropriately selected 23 facilities for potential controls measures, comprised of the 133 individual emission units

most likely to impact visibility in Class 1 areas based on their emission levels and distance to those areas. Of those emission units, NMED's plan includes control measures for 54 units, a far greater number of control measures than included in most state regional haze plans. Among those control measures are the retirements of 34 emissions units. Although NMED could not directly require retirements under the regional haze authority, those retirements will nevertheless assist in the state's efforts to improve visibility, and therefore they constitute an appropriate component of the SIP. In addition, the plan requires continued use of existing control measures at 11 units that, together with the expected retirements, will result in dramatic emission reductions—18,000 tons of NO_x and 5,000 tons of SO_2—that will make reasonable progress toward eliminating anthropogenic visibility degradation. The results of NMED's analysis are reasonable and should be submitted to EPA for approval.

However, some aspects of NMED's analysis, while perhaps appropriate for this round of the regional haze program, may be overly conservative for subsequent plans. For instance, the cost-effectiveness threshold of $10,000 per ton of emissions reduction selected by New Mexico for this plan is highly likely to be approved by EPA, but it is at the highest end of the spectrum of thresholds used by other states under the regional haze program. In future planning periods, NMED should reconsider whether such a high threshold is appropriate, and also reconsider whether establishing a bright line threshold is even necessary at all. In addition, although NMED was able to identify sufficient control measures to make reasonable progress in this planning period based solely on a "dollars per ton" cost-effectiveness metric, the cost-effectiveness of control measures imposed under this visibility-focused program could be more appropriately evaluated using a metric that accounts for visibility improvements, not just emission reductions. In particular, EPA's 2019 guidance recommends "dollars-per-inverse megameter" as a reasonable metric for evaluating costs per unit of visibility benefit. As visibility levels approach natural conditions and anthropogenic impairment approaches *de minimis* levels, weighing the compliance costs against potential visibility benefits of possible control measures will become more important than cost-effectiveness metrics based solely on emission reductions.

Finally, PNM supports NMED's recognition in the SIP that the deadline for submission has passed and that EPA's deadline for a federal implementation plan (FIP) is fast approaching. In light of these circumstances, PNM recommends that NMED include in its SIP an express request for EPA to act on the SIP despite the late submission because the SIP reflects the best plan for the state after extensive analysis by the expert state regulators best positioned to determine appropriate policy approaches for the state.

Again, we appreciate the opportunity to submit these comments on NMED's regional haze SIP for the state of New Mexico, and we would be happy to discuss the content of this letter with you at your convenience, please contact me at 505-241-2019 or Claudette.Horn@PNMResources.com if you have any questions.

Sincerely,



Claudette Horn
Director, Environment and Land Use Permitting
PNM

From:	Regionalhaze, NM, ENV
To:	Jones, Mark, ENV; Miller, Kenneth, ENV; Sanchez, Alex, ENV
Subject:	FW: [EXTERNAL] Regional Haze and the Valencia Natural Gas Plant
Date:	Thursday, September 19, 2024 8:30:52 AM
Attachments:	2028 Resource Evaluation - Stakeholder on Preliminary Results 06252024.pdf

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From: Camilla Feibelman <camilla.feibelman@sierraclub.org>
Sent: Thursday, September 19, 2024 8:29:10 AM (UTC-07:00) Mountain Time (US & Canada)
To: Regionalhaze, NM, ENV <NM.Regionalhaze@env.nm.gov>
Subject: [EXTERNAL] Regional Haze and the Valencia Natural Gas Plant

You don't often get email from camilla.feibelman@sierraclub.org. Learn why this is important

CAUTION: This email originated outside of our organization. Exercise caution prior to clicking on links or opening attachments.

Hello and thanks for the opportunity to comment on this initial phase of the Regional Haze State Implementation Plan. In a recent stakeholder meeting PNM implied that it would extend the life of what appears to be in the attached presentation, the Valencia Natural Gas Plant in Belen NM. The continued operation of this plant after 2028 for another 11.5 years before PNM has committed to be carbon free by 2040 could be a factor in haze generation. Thanks for your consideration, Camilla

---------- Forwarded message ---------
From: **Metzger, Phillip** <Phillip.Metzger@pnm.com>
Date: Tue, Jun 25, 2024 at 3:30 PM
Subject: PNM 55th Biweekly Resource Update: Presentation
To: Schwebke, Steven <Steven.Schwebke@pnm.com>, Aaron Gould <aaron.gould@westernresources.org>, Ahtza Chavez <ahtza@naeva.org>, Richard Alvidrez <ralvidrez@mstlaw.com>, Bradford Borman <Bradford.borman@prc.nm.gov>, Bryce.Zedalis1@prc.nm.gov <Bryce.Zedalis1@prc.nm.gov>, Caitlin Evans <Caitlin.evans@westernresources.org>, Camilla Feibelman <Camilla.feibelman@sierraclub.org>, Cara Lynch <lynch.cara.nm@gmail.com>, Charles de Saillan <desaillan.ccae@gmail.com>, Charles W. Kolberg <ckolberg@abcwua.org>, Chris Leger <Chris@interwest.org>, Colin Fitzhenry <cfitzhenry@consultbai.com>, Cydney Beadles <cydney.beadles@westernresources.org>, Daren Zigich <Daren.Zigich@prc.nm.gov>, Ed Rilkoff <Ed.Rilkoff@prc.nm.gov>, Elisha Leyba-Tercero <Elisha.leyba-tercero@prc.nm.gov>, Emma Douglas <Emma@jalblaw.com>, Etta Lockey <etta@fb.com>, Fallgren, Thomas <Thomas.Fallgren@pnm.com>, Fenton, Mark <Mark.Fenton@pnm.com>, Gabriella.dasheno@prc.nm.gov <Gabriella.dasheno@prc.nm.gov>, Gideon Elliot <gelliot@nmag.gov>, Goodwin, Stacey <Stacey.Goodwin@pnmresources.com>, greg meyer <gmeyer@consultbai.com>, Gwen Farnsworth <gwen.farnsworth@westernresources.org>, Harris, Dahl <Dahlharris@hotmail.com>, Heffington, Brent <Brent.Heffington@pnm.com>, Jack Sidler <Jack.Sidler@state.nm.us>, James Dauphinais <jdauphinais@consultbai.com>, Jeff Deyette <jdeyette@ucsusa.org>, Jeff Spurgeno <spurgeonJ@southwestgen.com>, Jeffrey Albright <JA@jalblaw.com>, Joan Drake <jdrake@modrall.com>, Jocelyn Barrett <jbarrett@nmdoj.gov>, Joseph Hernandez <joseph@naeva.org>, Joseph Yar <joseph@velardeyar.com>, Karl Braithwaite <karlbraith@gmail.com>, Keith Herrmann

<kherrmann@stelznerlaw.com>, Kelly Gould <kelly@thegouldlawfirm.com>, Lisa Tormoen Hickey <lisa@interwest.org>, Marah deMeule <mdemeule@bernco.gov>, Marc Tupler <Marc.Tupler@state.nm.us>, Matt Gerhart <Matt.Gerhart@sierraclub.org>, Melissa Shahzadeh <Melissa.M.Shahzadeh.nfg@army.mil>, Michael Gorman <mgorman@consultbai.com>, Mike Eisenfeld <Mike@sanjuancitizens.org>, Mona Blaber <monablaber@gmail.com>, Natalia Sanchez Downey <Ndowney@bernco.gov>, Nicholas Rossi <Nicholas.Rossi@prc.nm.gov>, Owen Smith <owensmith@meta.com>, Peter Gould <peter@thegouldlawfirm.com>, Salaz, Carey <Carey.Salaz@pnm.com>, Stephanie Dzur (Stephanie@Dzur-Law.com) <Stephanie@dzur-law.com>, Tom Singer <singer@westernlaw.org>, Wendy Atcitty <wendy@naeva.org>, Williams, Laurie A. <Laurie.Williams@pnmresources.com>, Winter, Nann M. <nwinter@stelznerlaw.com>, Duane, Thomas <Thomas.Duane@pnm.com>
Cc: Tupler, Marc, PRC <Marc.Tupler@prc.nm.gov>, Valerie Joe <vjoe@bernco.gov>, Monroy, Henry <Henry.Monroy@pnmresources.com>, Nanasi, Mariel <Mariel@seedsbeneaththesnow.com>

As requested, today's presentation is attached.

Thanks,

Phillip

--
****FOR URGENT OR TIMELY MATTERS PLEASE TEXT****
Camilla Feibelman
Sierra Club Rio Grande Chapter Director
Office: 505.243.7767 Cell: 505.715.8388
Web * Facebook * Twitter * Join * Donate
2215 Lead Ave SE, Albuquerque, NM, 87106
Pro (and Con) Nouns - Read these articles - She, Her, Hers
Working from occupied Tiwa land

For more information on the:
Para más información sobre el:
Sierra Club de Puerto Rico
adriana.gonzalez@sierraclub.org
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Stakeholder Briefing: Solicit input on 2028 RFP Evaluation and Planned 2028 Resource Regulatory Filing

JUNE 25, 2024

2028 RFP RESOURCE EVALUATION

- Focusing on 2028 needs only (~400 MW)
  - Valencia PPA contract expiration 5/31/2028
  - Includes higher PNM load forecast (~200 MW incremental)
  - System needs additional capacity resources – currently energy heavy

- Resource Optimization & Resource Adequacy Portfolio Analysis
  - Least cost (20-year NPVRR)
  - Least cost with CCSD project

PNM'S INTENT FOR RESOURCES IN CCSD

- 2028 Resource filing
  - Include a CCSD located resource in the 2024 anticipated regulatory filing either in the PNM preferred portfolio or an alternative portfolio

- 2029 -2032 Resource Portfolio Request for Proposal
  - Include a CCSD locational preference in the RFP that is issued for the recently accepted IRP resources

OPTIMAL PORTFOLIOS

Portfolio 1 - Least Cost:

- Extension of CT PPA, 161 MW
- Two ESA bids totaling 300 MW of 4 hr BESS
- Provides firm capacity of about 400 MW

Portfolio 2 – Least Cost with CCSD project:

- Extension of CT PPA, 161 MW
- One ESA bid totaling 150 MW of 4 hr BESS
- Three hybrid bids totaling 240 MW of Solar and 125 MW 4 hr BESS
- Provides firm capacity of about 400 MW
- 20 Year NPV Increase of $<$ 1% over Portfolio 1

MAIN TAKEAWAYS

- Portfolios 1 and 2:
  - Address capacity needs of system
  - Meet projected ETA carbon intensity and RPS requirements
  - Extend CT PPA for 11.5 years
  - Include Albuquerque Area 150 MW BESS
  - Utilize existing plant which requires no additional transmission construction cost benefitting customer costs
  - Result in no ELCC degradation in the near-term

- Portfolio 1 is least cost and includes exclusively capacity resources
  - Includes a second Albuquerque Area 150 MW BESS

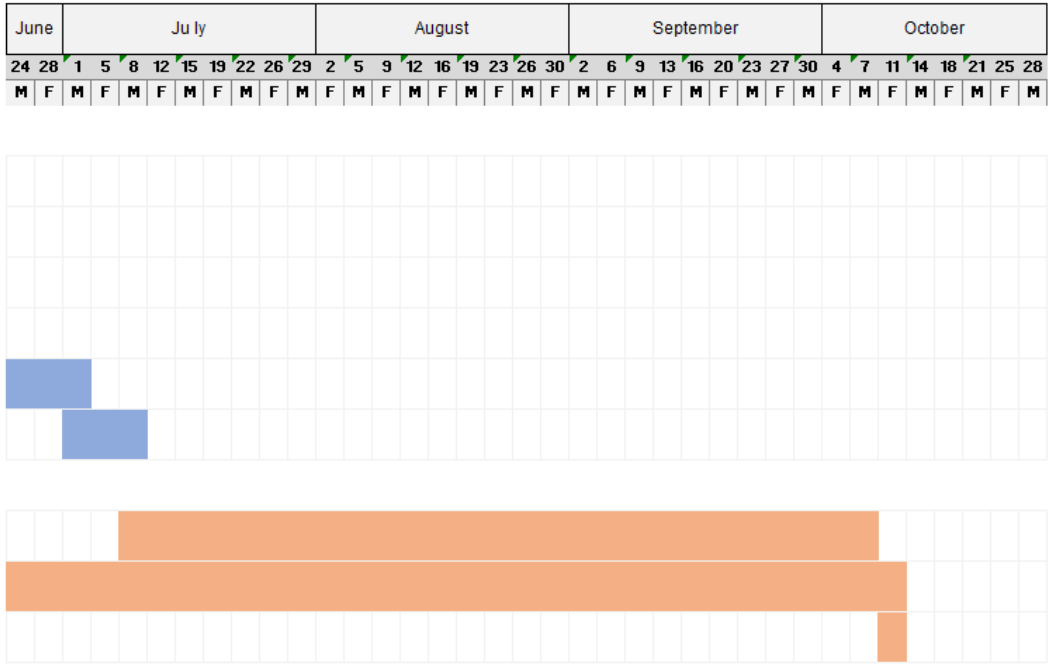
- Portfolio 2 provides additional resources in the CCSD
  - Lowest cost CCSD portfolio utilizes utility owned solar hybrid project
  - Customer Benefits: Provides benefits to San Juan area community and contributes to CCSD tax base
  - Satisfies IRP Action Plan commitment to utilize existing resource locations where possible
  - Alleviates transmission congestion flowing out of system load center to Four Corners
  - No imputed debt costs to customers over ESA options

NEXT STEPS

- Complete Phase III analysis
  - LOLE validation remaining
  - Revised analysis results with best and final offer prices
- Review analysis results with IE
- Commence Contract Negotiations with counterparties
- 2028 Resource Filing with NMPRC - Targeting October 2024

REMAINING SCHEDULE

TASK	PROGRESS	START	END
RFP Bid Evaluation			
Phase 1 Screening	100%	3/1/24	3/14/24
Phase 2 Shortlist	95%	3/15/24	5/31/24
Phase 3 Modeling	75%	5/1/24	6/18/24
Stakeholder Meeting	0%	6/18/24	6/18/24
Management Approval	0%	6/18/24	7/1/24
Independent Evaluator Review	0%	7/2/24	7/10/24
Approvals, Contracts & Filing			
Contract Negotiations	0%	7/11/24	10/8/24
Regulatory Case Prep	0%	6/18/24	10/11/24
Regulatory Filing	0%	10/11/24	10/11/24



Thank You!



Kelly Fuller

Please find attached WildEarth Guardians' comments on the draft New Mexico Regional Haze State Implementation Plan Revision Second Planning Period (2019-2028)

September 20, 2024

Mark Jones
New Mexico Environment Department (NMED)
Air Quality Bureau
525 Camino de Los Marquez, Suite 1
Santa Fe, NM, 87505
nm.regionalhaze@env.nm.gov

Re: Comments on New Mexico's Draft Regional Haze SIP

Dear Mr. Jones:

Thank you for this opportunity to submit comments on New Mexico's draft Regional Haze State Implementation Plan Revision for the Second Planning Period (2019-2028). I am writing on behalf of WildEarth Guardians, which protects and restores the wildlife, wild places, wild rivers, and health of the American West. WildEarth Guardians has more than 206,000 members and supporters across the United States, including in New Mexico. Our members and supporters cherish, visit, recreate, live, and make their livelihoods in and near America's national parks and wilderness areas. Visibility in these parks and wilderness areas is important to them. The pollutants that cause regional haze in New Mexico's Class I areas are additionally significant because they can affect community health, especially in parts of the state that are hard hit by the impacts of oil and gas extraction, such as the Greater Chaco region and the SE corner/Carlsbad region. Emissions reductions are necessary to improve visibility in New Mexico's national parks and wilderness areas; they will also improve air quality in frontline and fenceline communities that bear the brunt of New Mexico oil and gas extraction.

We support the National Park Service's requests for additional emissions controls in its July 26, 2024 comments. We particularly support its recommendations on cost effectiveness (pages 5 and 6), recommendations on selective catalytic reduction (pages 5-8), and requests that NMED further reduce NOx emissions by (1) addressing smaller engine size classes and (2) requiring lower NOx limits for various engine size classes/configurations (page 26).

Given NMED's staff statement in the webinar for this SIP that virtually none of the equipment analyzed for this SIP currently has emissions controls, it is important that controls be implemented as quickly as possible, noting again that controls not only improve visibility, but also remove pollutants that can affect community health.

We note that the Appendix F of the draft Regional Haze SIP, which contained comments from the U.S. Forest Service and the National Park Service, did not include comments from the U.S. Fish and Wildlife Service, so the public was unable to review them during the informal comment period. Apparently USFWS did provide comments, because one comment was included on NMED's Regional Haze webpage. USFWS's comments should be posted online with the draft SIP before the hearing, so that the public can review.

Thank you again for this opportunity to provide comment and please notify us of the upcoming public hearing.

Sincerely yours,

Kelly Fuller

Kelly Fuller
Climate and Energy Program Director
WildEarth Guardians
301 N. Guadalupe St., Ste. 301
Santa Fe, NM 87501
kfuller@wildearthguardians.org
(505) 501-8125

From: Kelly Fuller
To: Jones, Mark, ENV
Subject: [EXTERNAL] Request for USFWS comments on NM Regional Haze draft SIP
Date: Friday, September 20, 2024 12:17:11 PM

You don't often get email from kfuller@wildearthguardians.org. Learn why this is important

CAUTION: This email originated outside of our organization. Exercise caution prior to clicking on links or opening attachments.

Hi Mark,

Would it be possible to get a copy of the U.S. Fish and Wildlife Service's comments on New Mexico's draft Regional Haze SIP? They were not included in Appendix F that is posted on NMED's regional haze website. But USFWS does appear to have commented because a quote from them is posted on the NMED Regional Haze website in the section titled "Copies of the draft plan and rule are available for download at the following links:"

Thanks,

Climate & Energy Program Director
she/her

(505) 501-8125
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McGuireWoods

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September 20, 2024

Via Email: nm.regionalhaze@env.nm.gov
Mark.jones@env.nm.gov

Mr. Mark Jones
New Mexico Environment Department
Air Quality Bureau
525 Camino de Los Marquez - Suite 1
Santa Fe, New Mexico 87505

Comments of Enterprise Field Services, LLC on NMED's Draft Regional Haze State Implementation Plan Revision and 20.2.68 NMAC - Regional Haze Requirements

Dear Mr. Jones:

Enterprise Field Services, LLC ("Enterprise") submits herein to the New Mexico Environment Department ("NMED") comments on NMED's draft State of New Mexico Regional Haze State Implementation Plan Revision Second Planning Period (2019-2028) ("Draft SIP") and 20.2.68 NMAC – Regional Haze Requirements ("Companion Rule").

I. Introduction

On August 26, 2024, the NMED announced the release of a Draft SIP to address the Clean Air Act's ("CAA") regional haze requirements for the second planning period of the program (2018-2028). NMED established a comment deadline of September 20, 2024 for these proceedings.[1]

Enterprise is the owner and operator of three facilities that would be subject to the Draft SIP:

- South Carlsbad Compressor Station located in Eddy County, New Mexico (South Carlsbad) – located approximately 26 miles from the nearest Class I Area

[1] *See* NMED, Regional Haze Planning, https://www.env.nm.gov/air-quality/reg-haze/.

- Blanco C & D Compressor Station located in San Juan County, New Mexico (Blanco) – located approximately 39 miles from the nearest Class I Area

- Chaco Gas Plant located in San Juan County, New Mexico (Chaco) – located approximately 49 miles from the nearest Class I Area[2]

Throughout the development of the Draft SIP, Enterprise has engaged with NMED, providing information to support the state's four-factor analyses, responding to information requests, and proposing reasonable regulatory approaches. The Draft SIP, however, takes a very different approach than NMED appeared to be considering during these discussions. Despite indications that NMED agreed with Enterprise that selective catalytic reduction ("SCR") for the control of oxides of nitrogen ("NOx") was not feasible at the Enterprise facilities, the Draft SIP would impose emission limits for eight (8) of the thirteen (13) Enterprise units evaluated that are based on installation and operation of SCR.

NMED has not appropriately evaluated "reasonable progress," as defined by the CAA, for the Enterprise facilities addressed in the Draft SIP. As described in these comments, the Draft SIP is based on an incorrect determination of SCR's technical feasibility and faulty and unrealistic cost assumptions. Further, the SIP would impose control requirements to satisfy the CAA's reasonable progress standard without considering visibility improvement in any meaningful way. Failure to consider visibility and to take all of the statutory factors into account when devising the control requirements for the Enterprise facilities is arbitrary and capricious and contrary to the requirements of the CAA. For all of these reasons, Enterprise requests that NMED withdraw the Draft SIP, reconsider its analysis consistent with these comments, and develop more reasonable and better-supported control requirements for the Enterprise facilities.[3]

II. Background on the Regional Haze Program

The CAA's visibility protection provisions establish as a national goal "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas[4] which impairment results from manmade air pollution." CAA § 169A(a)(1). The Act directs the U.S. Environmental Protection Agency ("EPA") to issue regulations designed "to assure … reasonable progress toward meeting the national goal" and to require each state to submit a SIP containing "such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal." *Id*. § 169A(a)(4), (b)(2). Accordingly, pursuant to CAA section 169A, the ultimate requirement

[2] Collectively, the "Enterprise facilities."

[3] If NMED plans to proceed to seek approval of the Draft SIP, Enterprise requests, in the alternative, that NMED submit a partial SIP, excluding the Enterprise facilities, to allow Enterprise and NMED to work together to develop a separate SIP submittal that more appropriately addresses the Enterprise facilities.

[4] Class I federal areas are specified units of federal land receiving special protections, such as National Parks and Wilderness areas.

states must satisfy with their regional haze SIPs is to provide for "reasonable progress" towards the national visibility goal.

EPA implements the regional haze program in successive ten-year "planning periods." The first planning period ran from 2008 to 2018. The second planning period of the program covers the period from 2018 to 2028. SIPs to address second planning period control requirements were due to EPA by July 31, 2021. 40 C.F.R. § 51.308(f). As NMED notes in its announcement of the availability of the Draft SIP, EPA "is currently under a September 29, 2024 deadline to approve New Mexico's regional haze plan or promulgate a federal plan for New Mexico satisfying the visibility protection requirements of the Clean Air Act."[5] That deadline, negotiated with environmental groups, is already well past the July 31, 2021 regulatory deadline for second planning period regional haze SIPs. 40 C.F.R. § 51.308(f).

A regional haze SIP has a number of required elements. Most importantly for purposes of these comments, regional haze SIPs must include: (1) technical analyses to inform and support the SIP's control determinations, including calculation of visibility conditions, development of the "uniform rate of progress" ("URP") for each of the state's Class I areas, and interstate and Federal Land Manager ("FLM") consultation demonstrations; (2) a Long-Term Strategy ("LTS"), which includes measures necessary to make reasonable progress toward the national visibility goal; and (3) reasonable progress goals ("RPGs"), which are visibility goals for each mandatory Class I federal area located in the state and which are based on the control measures included in the LTS.

The CAA and EPA's regional haze rule ("RHR") require states to evaluate potential control requirements for sources within their jurisdiction using the four reasonable progress factors: "[1] the costs of compliance, [2] the time necessary for compliance, [3] the energy and non-air quality environmental impacts of compliance, and [4] the remaining useful life of any potentially affected sources." *Id*. § 51.308(f)(2)(i). If a four-factor analysis supports the establishment of new control requirements, those requirements may be appropriate for inclusion in the state's regional haze SIP. Under certain conditions, a state may be required to include existing control measures in their regional haze SIPs to ensure that the state continues to make reasonable progress.

EPA guidance establishes that states may consider visibility alongside the four statutory factors when evaluating controls, stating "EPA has interpreted the CAA and RHR as allowing states to consider visibility alongside the four statutory factors when determining the emission reduction measures that are necessary to make reasonable progress."[6] In fact, EPA "anticipate[s] that the outcome of the decision-making process by a state regarding a control measure may most often depend on how the state assesses the balance between the cost of compliance and the

[5] https://www.env.nm.gov/air-quality/reg-haze/.

[6] EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period at 12 (July 8, 2021) ("Clarifications Memo").

visibility benefits."[7] Moreover, as discussed above, the CAA requires states to make reasonable progress determinations that are tied by law to consideration of the national visibility goal.

In addition, under the RHR, states must determine and take into account URP, *i.e.*, the rate of progress that would be needed to attain natural visibility conditions by the year 2064, assuming consistent progress is maintained from the baseline to the program's aspirational endpoint. *Id*. § 51.308(f)(3)(ii)(A). Under the RHR, a state may establish an RPG that differs from the URP if the state demonstrates that the URP for the Class I area in question would not be reasonable. A state makes such a showing by conducting a reasonable progress analysis that considers the four reasonable progress factors and makes a "robust" demonstration. *Id*.[8] The RHR also allows states to adjust the URP to account for the effects of international emissions and emission from prescribed fires on wildlands. 40 C.F.R. § 51.308(f)(1)(vi)(B).

States whose emissions may cause visibility impairment in another state's Class I area and states with Class I areas that may experience visibility impairment caused by emissions from other states may be subject to an interstate-consultation requirement. *Id*. § 51.308(f)(2)(ii). The purpose of that requirement is to provide a forum for states to decide collaboratively on reasonable emission reductions and appropriate apportionment of responsibility for reducing emissions during each planning period of the regional haze program. In addition, all states are subject to a requirement to consult with the FLMs in the development of their SIPs. *Id*. § 51.308(i).

III. The New Mexico Environment Department Has Not Adequately Engaged with the Regulated Community.

During the development of the Draft SIP, Enterprise undertook extensive work to assist in the preparation of four-factor analyses for the Enterprise facilities. Enterprise further submitted written materials explaining potential legal and policy justifications to support the state's reasonable progress determinations. To further those efforts, Enterprise met multiple times with NMED staff. Enterprise worked with the state to understand its process, the emission controls under consideration, and the information NMED needed to make informed reasonable progress determinations. As noted in Appendix C, this engagement included:

- The FFA completed by Trinity Consultants for Enterprise Field Services, LLC (Enterprise) and submitted to NMED on 10/30/19 and 11/14/19, respectively.
- Additional information provided by Enterprise on 2/14/20, 2/26/20, 5/19/20, 6/2/20, 9/8/20, 10/1/20, 3/4/21, and 8/30/23.
- Detailed discussions between Enterprise and NMED on 8/28/20 and 7/13/23.

[7] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 37 (Aug. 20, 2019) ("2019 Guidance").

[8] The statutory basis for EPA's "robust" demonstration requirement is, at best, unclear.

• Written comments submitted to NMED regarding Draft Final Cost Evaluations on 1/15/24.[9]

In addition to the engagement described above, Enterprise, in a February 19, 2020 presentation given to NMED, explained using aerial photographs that there was insufficient space available for SCRs at each of the Enterprise facilities.[10] At no time during the many interactions since that presentation did NMED indicate that it was evaluating SCR for the Enterprise facilities or that it had reason to reject Enterprise's assertions as to the problems posed by space constraints. On the contrary, in an email dated December 20, 2023, NMED provided Enterprise with " draft final cost evaluations" for the Enterprise facilities to facilitate Enterprise providing comments on those cost evaluations.[11] Two spreadsheets containing the state's cost analysis were attached to this email and indicated that NMED had concluded that, due to space constraints, other site-specific factors, and costs for other similar facilities in New Mexico, "SCR is cost prohibitive" for the Enterprise facilities.[12]

Despite all of this early engagement, NMED has now released its Draft SIP with vastly different conclusions as to the feasibility of SCR and would impose especially stringent emission rate limits on the Enterprise facilities as a result. Had NMED shared with Enterprise that it was considering a significant change in course, Enterprise would have worked to provide the state with additional information to further assist in its assessment of SCR. Unfortunately, Enterprise did not have that opportunity. Similarly, NMED has now provided only a 25-day period for comment on the Draft SIP. Although Enterprise understands that the regulatory process in New Mexico will provide additional opportunities to participate, by failing to transparently engage with Enterprise during development of the Draft SIP, NMED has substantially limited Enterprise's ability to develop and provide much-needed information to correct the record in these proceedings.

In the limited time available, Enterprise has developed the analysis presented here, which further demonstrates the significant costs of SCR for the Enterprise facilities. Because NMED is using SCR as the basis of the NOx limits, as expressed in the Companion Rule, and due to the limited time available to evaluate SCR, Enterprise has not been able to quantify the full scope of facility modifications, with their attendant cost, complexity, and uncertainty, that would be needed to attempt to achieve the proposed NOx limits. This would have required a full constructability evaluation as well as an analysis of infrastructure reconfiguration and potential electrical upgrade requirements. Enterprise appreciates that NMED has committed to considering any additional information that may be developed subsequent to the close of the current

[9] Draft SIP, App. C at 65. For ease of reference, Citations to NMED Appendices refer to the PDF pagination rather than the pagination of the individual reports contained therein.

[10] Enterprise Products Partners, L.P., Regional Haze Planning Meeting (February 19, 2020) (Attachment A). Similar images appear in the Draft SIP, App. D at 500-501, 597, 657.

[11] NMED, Email Correspondence and attachments (Dec. 20, 2023) (Attachment B).

[12] *Id*. at attachments, SCR Tab.

comment period and to reasonably accommodate the need for additional time that may be needed to complete complex analyses and to obtain information from third parties.

The information that is available makes clear that SCR is not necessary to make reasonable progress when considered in light of the four factors and the limited visibility improvement that could be achieved through installing these controls. Accordingly, just as Enterprise has worked diligently in very short time to provide NMED with information that necessitates revising the Draft SIP's requirements for the Enterprise facilities, NMED must revise the Draft SIP before submitting it for review by the state's Environmental Improvement Board ("EIB"). Indeed, proceeding to seek approval of the Draft SIP after consideration of the information provided in these comments would be unreasonable and unsupported by the record. Accordingly, NMED should withdraw the Draft SIP or substantially revise it based on these comments before proceeding with EIB review.[13]

IV. New Mexico Has Unreasonably Refused to Consider Visibility in Violation of the CAA.

As explained above, section 169A of the CAA imposes one overarching requirement on states: they must include in their SIPs "such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal." 42 U.S.C. § 7491(b)(2). The national goal that states must ensure "reasonable progress" towards is a visibility goal: "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." *Id*. § 7491(a)(1). While states must consider the four reasonable progress factors when assessing the level of progress that is reasonable, plainly, states cannot make a determination as to the measures needed to ensure reasonable progress without considering the overall goal of the program.[14] Thus, as should be clear, a regional haze SIP must be based on consideration of visibility to satisfy the CAA.

In describing how it selected control requirements for sources subject to the SIP, NMED says:

> NMED did not directly consider the visibility benefits of potential control measures when making its control determinations. EPA has

[13] If, in spite of these comments, NMED intends to proceed with finalizing the Draft SIP without appropriate revisions, Enterprise requests that NMED provide Enterprise with the opportunity to respond to any of the Department's remaining questions and to provide any necessary additional information. As noted above in footnote 3, addressing the Enterprise facilities in a separate SIP submittal could provide NMED with additional time to respond to these comments (as well as any additional information that is developed) while still proceeding with approval of the remainder of the Draft SIP.

[14] In its Clarifications Memo, EPA appears to assert that states may only consider visibility in certain ways or for certain purposes. Clarifications memo at 13. For instance, EPA says visibility should not be used to "summarily dismiss" cost-effective controls, but that it could be used to select among different cost-effective controls. *Id*. EPA has presented no principled basis for limiting consideration of visibility. Moreover, as described above, the CAA must be interpreted to require consideration of visibility in support of measures needed to make reasonable progress under the regional haze provisions of the Act.

> consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making control determinations. NMED's approach is based on the assumption that substantial reductions in emissions of NOx and SO_2 will translate into visibility benefits.

Draft SIP at 104-05. According to NMED, therefore, the state did not consider visibility other than to assume that emission reductions would translate to visibility benefits, essentially failing to consider visibility at all. This is an unreasonable approach to developing a regional haze SIP, and it is inconsistent with the requirement that states develop SIPs that ensure reasonable progress toward the national visibility goal. In short, failure to consider visibility is a failure to consider a factor Congress intended states to take into account when developing regional haze SIPs. NMED has therefore failed to consider "an important aspect of the problem," which renders the Draft SIP arbitrary and capricious under the law. *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43, (1983) ("Normally, an agency rule would be arbitrary and capricious if the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise.")

In addition, New Mexico law requires that the EIB consider visibility when taking action. NM Stat § 74-2-5(f) (2023). The EIB is tasked with weighing visibility improvements against "the public interest, including the social and economic value of the sources and subjects of air contaminants;" as well as "technical practicability and economic reasonableness of reducing or eliminating air contaminants from the sources involved and previous experience with equipment and methods available to control the air contaminants involved." *Id*. The EIB cannot fulfill its statutory obligations without an assessment of visibility by NMED. On the contrary, in the absence of a visibility assessment in support of the Draft SIP, the EIB will have no choice but to disapprove it for failure to comport with the CAA minimal requirements.[15]

NMED must correct this shortcoming in the Draft SIP before proceeding to seek approval from the EIB. A proper consideration of visibility, moreover, as described in the next section, demonstrates that existing controls at the Enterprise facilities are sufficient to address the CAA's reasonable progress requirement for the second planning period and that SCR cannot be justified.

V. Any Reasonable Assessment of Visibility Demonstrates that Additional Controls, Including SCR, Cannot Be Justified for the Enterprise Facilities.

All evidence in the record supports a finding that visibility conditions in Class I areas potentially affected by the Enterprise facilities are already achieving reasonable progress. The evidence in the record further establishes that any new emission control requirements for the

[15] While the technical information included in the Draft SIP on visibility conditions is useful information, without analysis of visibility impacts and an assessment of how such impacts should figure into control determinations by NMED in the first instance, the EIB will not have an adequate basis on which to evaluate the Draft SIP.

Enterprise facilities will result in, at most, imperceptible visibility impacts. In short, considered by every metric, the visibility effects that would result from the requirements of the Draft SIP cannot support the imposition of costly new control requirements. As such, the Draft SIP should be revised to recognize that existing controls at the Enterprise facilities are sufficient to ensure reasonable progress.

The progress achieved to date and projected for the future without requiring additional controls, including SCR, at the Enterprise facilities should be deemed sufficient to address the reasonable progress requirement for the second planning period. The Draft SIP acknowledges, for instance, that all Class I areas affected by New Mexico sources "have shown visibility improvement over the monitoring period." Draft SIP at 42. This improvement, when compared to the URP, demonstrates that the areas affected by New Mexico sources are generally improving faster than the URP metric. The Draft SIP explains:

> NMED's glidepath checks show that eight of New Mexico's nine Class I Areas are projected to fall below the URP glidepath in 2028, which is indicative of a faster rate of improvement than the URP. Only Salt Creek Wilderness Area in Chaves County is projected to be above the glidepath, indicating a slower rate of improvement than the URP.

Draft SIP at xiii. Despite devoting a chapter of the Draft SIP to describing the results of its comparison of the URP to visibility conditions, NMED fails to draw any conclusions or present any analysis of how it took the performance of these Class I areas relative to the URP into account in evaluating requirements for the Draft SIP. Indeed, it does not appear that NMED actually took the URPO into account in any way. NMED must include such an analysis to satisfy the requirements of the RHR and to provide a well-supported SIP. Any reasonable assessment of the URP, moreover, supports the conclusion that additional controls for the Enterprise facilities, including SCR, are not needed for reasonable progress.[16]

In each of the four-factor assessments that Enterprise submitted to NMED to assist in the development of the Draft SIP, Enterprise's consultant included an assessment of likely visibility impacts that would result from controls at the Enterprise facilities. For Blanco, Enterprise reported:

> The Blanco C&D Compressor Station is located approximately 50 miles from the Mesa Verde Class I areas at a wind vector range of approximately 155 degrees to 165 degrees (SSE). According to 2015 meteorological data collected in Bloomfield, NM . . . wind blows from this direction range at a frequency of only 2.4%.

[16] As explained below, although Salt Creek Wilderness Area is not yet projected to be below the URP glidepath, a Q/d assessment for South Carlsbad using recent emissions data shows that its emissions would have minimal impacts on visibility that fall below NMED's screening threshold for bringing sources forward for four-factor analysis.

> Moreover, when the wind direction is within this range, the wind speed is typically relatively low; the frequency of wind speeds greater than 3.09 m/s (or ~7 mph) is only 0.3%, or about 25 hours per year. Higher wind speeds would be needed to effectively transport emissions from Blanco to the Mesa Verde Class I area. Moreover, over the 50 miles of transport, pollutants undergo significant dispersion. While full dispersion and photochemical modeling would be needed to more robustly evaluate Blanco's impact, based on this evidence, Blanco's impact on visibility is likely insignificant.

See Draft SIP, App. D. at 488.

Similarly, for Chaco, Enterprise reported:

> The Chaco Gas Plant is located approximately 50 miles from the Mesa Verde Class I area at a wind vector range of approximately 155 degrees to 165 degrees (SSE). According to 2015 meteorological data collected in Bloomfield, NM . . . wind blows from this direction range at a frequency of only 2.4%. Moreover, when the wind direction is within this range, the wind speed is typically relatively low; the frequency of wind speeds greater than 3.09 m/s (or ~7 mph) is only 0.3%, or about 25 hours per year. Higher wind speeds would be needed to effectively transport emissions from Chaco to the Mesa Verde Class I area. Moreover, over the 50 miles of transport, pollutants undergo significant dispersion. While full dispersion and photochemical modeling would be needed to more robustly evaluate Chaco's impact, based on this evidence, Blanco's impact on visibility is likely insignificant.

Id. at 581.

For South Carlsbad, Enterprise reported:

> The South Carlsbad Compressor Station is located approximately 16.2 miles [sic][17] from the Carlsbad Caverns Class I area at a wind vector range of approximately 60 degrees to 70 degrees (NE). According to 2017 meteorological data collected in Carlsbad. . . wind only blows from this direction at a frequency of 1.4% or approximately 120 hours per year. Moreover, over the 16 miles of transport, pollutants would undergo significant dispersion. While

[17] The distance is 25.88 km (16.1 miles) according to SIP table 6-1. Draft SIP at 96.

> full dispersion and photochemical modeling would need to be conducted to more accurately evaluate South Carlsbad's impact, based on this evidence, the facility's impact on visibility is likely insignificant.

Id. at 644.

As explained above, NMED has not conducted any additional visibility assessment or reached any conclusions about the impact of the Enterprise facilities on visibility in Class I areas. Accordingly, the only information in the record supports the conclusion that the impacts from the controls under evaluation are not likely to be meaningful. NMED cannot nevertheless impose emission control requirements without even considering this crucial information, much less carefully weighing it.

Since preparation of the NMED and Enterprise four-factor assessments, additional data has become available to demonstrate that visibility impacts from Chaco and South Carlsbad—and any benefit that would result from further controlling their emissions—have grown even smaller. As shown in the table below, since 2016, emissions from Chaco and South Carlsbad have generally fallen, with resulting Q/d values falling appreciably as well. Most significantly, the Q/d values for South Carlsbad for four of the last five years have been below the state's adopted Q/d threshold of 5.6. This is adequate grounds in itself to remove control requirements for South Carlsbad from further consideration.

	Blanco		Chaco		South Carlsbad	
Year	Q	Q/d	Q	Q/d	Q	Q/d
2014	513.2	8.1	2250.0	28.0	149.5	5.8
2015	528.3	8.3	2175.6	27.1	160.3	6.2
2016	494.8	7.8	2270.7	28.3	153.0	5.9
2017	515.0	8.1	1943.9	24.2	156.5	6.0
2018	512.6	8.1	1976.2	24.6	160.0	6.2
2019	573.7	9.1	1829.2	22.8	133.8	5.2
2020	883.1	13.9	1861.0	23.2	135.6	5.2
2021	591.5	9.3	1826.9	22.8	140.2	5.4
2022	456.9	7.2	777.1	9.7	121.6	4.7
2023	658.7	10.4	707.6	8.8	156.7	6.1

Q = Sum of reported annual NOx and SO2 emissions (tons)

d = distance from Class I area (km) per Table 6-1 of draft SIP

Blanco =	63.4	km
Chaco =	80.2	km
S. Carlsbad =	25.9	km

Finally, the lack of a visibility assessment obscures the truly de minimis nature of the visibility impacts from the Enterprise facilities further demonstrating why refusing to consider visibility is unreasonable and inconsistent with the CAA. When EPA promulgated a Federal Implementation Plan ("FIP") to address regional haze for New Mexico during implementation of the first planning period of the program, EPA conducted a full visibility assessment to evaluate whether SCR could be justified. *See* 76 Fed. Reg. 491 (Jan. 5, 2011) (Proposed FIP for New Mexico). In determining that SCR could be justified for the San Juan Generating Station, EPA determined that the installation and operation of SCR would result in a visibility improvement of 21.69 deciviews across 16 different Class I areas. *Id*. at 503. Improvements within individual Class I areas ranged from 0.31 deciviews to 3.11 deciviews. *Id*. To put this context, EPA says that a 0.5 deciview impact "contributes" to visibility impairment, a 1.0 deciview impact "causes" visibility impairment, and a 1.0 deciview impact is generally the threshold for human perception of a change in visibility conditions. To further put this into perspective, to achieve this level of visibility improvement, EPA projected that the FIP would eliminate 17,518 tons per year of NOx. *Id*. at 502, Table 7.

By contrast, the Draft SIP's tons per year NOx reductions estimated for Blanco are 974.4 tons. Draft SIP at 115. For Chaco, they are 363.6 tons. *Id*. at 116. For South Carlsbad, they are 138.7. *Id*. at 118. The visibility benefits that might result from these reductions would be a mere fraction of those previously deemed sufficient to justify requiring SCR. Accordingly, the minimal visibility impacts that may result from emissions from the Enterprise facilities cannot reasonably serve as the basis for imposing the enormously costly, if not infeasible, emission controls contemplated in the Draft SIP.

A full and reasonable evaluation of visibility, as required by the CAA and New Mexico law, demonstrates that the Draft SIP's control determinations for the Enterprise facilities are unsound and must be revised. The only information in the record supports the conclusion that the visibility impacts of the Enterprise facilities, and the visibility improvements that could be achieved with additional controls, do not support requiring additional costly requirements to address reasonable progress at this time. NMED is obligated to consider this information and to revise the requirements of the Draft SIP to better align the Draft SIP's requirements with the requirements of the CAA.

VI. New Mexico Has Failed to Justify Its Decision to Pursue Reductions in Nitrogen Oxides.

The Draft SIP explains that visibility impairment is overwhelmingly dominated by "ammonium sulfate, organic mass, and coarse mass on both the Most Impaired Days and the Clearest Days." Draft SIP at 53.[18] EPA guidance makes clear that it is appropriate for states to evaluate controls for the most significant visibility-impairing pollutants:

[18] The only exceptions are Salt Creek Wilderness and San Pedro Parks Wilderness, "when ammonium nitrate was one of the top three contributors instead of either organic mass or coarse mass." Draft SIP at 53. None of the Enterprise facilities is located near these areas or could reasonably be expected to influence their visibility conditions. Blanco is 471.14 kilometers ("km") from Salt Creek and 89.47 km from San Pedro. Chaco is 461.68 km

> When selecting sources for analysis of control measures, a state may focus on the PM species that dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors. Also, it may be reasonable for a state to not consider measures for control of the remaining pollutants from sources that have been selected on the basis of their emissions of the dominant pollutants.

2019 Guidance at 11. Had NMED followed this guidance and focused on the greatest pollutants of concern, the Enterprise facilities would not have even been considered for additional controls. This is itself an adequate basis for removing the Enterprise facilities from further consideration for reasonable progress controls.

EPA's guidance goes on to provide one pertinent example:

> For example, organic mass by carbon (OMC) light extinction might be dominant in the IMPROVE data for a western Class I area on the average of the 20 percent most anthropogenically impaired days, even though days heavily affected by fires will tend not to be included in the 20 percent most anthropogenically impaired days. This may cause sulfate to account for only a small percentage of total light extinction. However, it could be clear that most of the OMC is natural and that sulfate dominates anthropogenic light extinction. In this situation, we recommend that a state consider SO_2 sources and SO_2 control measures.

This is the situation facing New Mexico. Yet instead of focusing on SO_2 controls, as the data suggests would be appropriate and a*s EPA guidance calls for*, the state has unreasonably focused on the negligible impacts that might result from NOx emissions, including the relatively small NOx emissions from the Enterprise facilities.

New Mexico rationale for pursuing NOx reductions is that "[t]he largest haze reductions over time (i.e., the largest reduction in individual species' contributions to light extinction) are generally associated with ammonium sulfate and ammonium nitrate, which have likely occurred due to reduced SO_2 and NOx emissions since EPA first promulgated the Regional Haze Rule in 1999." Draft SIP at 53. Although significant reductions in NOx in the past may have been associated with commensurate reductions in haze, there is no basis for concluding that eliminating minor amounts of NOx will have a significant effect on visibility at this time.

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from Salt Creek and 99.97 km from San Pedro. South Carlsbad is 141 km from Salt Creek and 477.04 km from San Pedro.

Indeed, as described above, EPA's FIP for New Mexico for the first regional haze planning period would have eliminated 17,518 tons per year of NOx. *Id*. at 502, Table 7 and improved visibility by an appreciable 21.69 deciviews across 16 different Class I areas. 76 Fed. Reg. at 502-03. EPA withdrew that FIP and approved a subsequently submitted regional haze SIP for New Mexico that achieved *even greater* emission reductions and visibility improvements than the FIP. See Approval and Promulgation of Implementation Plans; New Mexico; Regional Haze and Interstate Transport Affecting Visibility State Implementation Plan Revisions, 79 Fed. Red. 60,985 (Oct. 9, 2014). The Draft SIP achieves nothing approaching this level of visibility improvement from its proposed NOx controls.

For all of these reasons, NMED has "offered an explanation for its decision [to focus on NOx] that runs counter to the evidence before the agency." *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43, (1983). New Mexico, consistent with EPA guidance, should elect to focus the current regional haze SIP on the visibility impairing pollutants of most significance. It should not continue to pursue NOx controls for this planning period. For that reason, NMED should revise the Draft SIP to acknowledge that existing controls at the Enterprise facilities are adequate to ensure reasonable progress.

VII. NMED Has Adopted an Unreasonable Q/d Screening Threshold.

The Draft SIP explains that NMED performed Q/d assessment to identify sources with emissions significant enough to warrant further evaluation pursuant to the four factors. Draft SIP at 93. NMED adopted a Q/d screening threshold of 5.6. *Id*.

This screening threshold is significantly out of step with the thresholds used by other states, including those that have previously been approved as reasonable for use in the regional haze program by EPA. Indeed, every state to adopt such a screening threshold appears to have adopted one substantially higher than New Mexico:

- Air Plan Partial Approval and Partial Disapproval; Wyoming; Regional Haze Plan for the Second Implementation Period, 89 Fed. Reg. 63,030, 63,042 (August 1, 2024) (screening threshold of Q/d > 10).

- Air Plan Partial Approval and Partial Disapproval; Utah; Regional Haze State Implementation Plan for the Second Implementation Period; Air Plan Disapproval; Utah; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 89 Fed. Reg. 67,208, 67,220 (August 19, 2024) (screening threshold of Q/d ≥ 6).

- Air Plan Approval; Wisconsin; Second Period Regional Haze Plan, 89 Fed. Reg. 65,492, 65,503 (August 9, 2024) (screening threshold of 10).

- Approval and Promulgation of Air Quality Implementation Plans; State of Florida; Regional Haze State Implementation Plan, 77 Fed. Reg. 31,240, 31,253

(May 25, 2012) (screening threshold of 50).

- Partial Approval and Disapproval of Air Quality Implementation Plans; Arizona; Regional Haze State Implementation Plan for the Second Implementation Period and Prong 4 (Visibility) for the 2015 Ozone and 2012 Particulate Matter Standards, 89 Fed. Reg. 47,398, 47,412 (May 31, 2024) (screening threshold of 10).

- Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan: Proposal of Best Available Retrofit Technology (BART) and Interstate Transport Provisions, 83 Fed. Reg. 43,586, 43,596 (Aug. 27, 2018) (screening threshold of 10).

- Approval and Promulgation of Air Quality Implementation Plans; Montana; Regional Haze Federal Implementation Plan, 82 Fed. Reg. 17,948, 17,955 (Apr. 14, 2017) (screening threshold of 10).

- Approval and Promulgation of Implementation Plans; South Dakota; Regional Haze State Implementation Plan, 76 Fed. Reg. 76,646, 76,661 (Dec. 8, 2011) (screening threshold of 10).

- Approval and Promulgation of Implementation Plans; State of Colorado; Regional Haze State Implementation Plan, 77 Fed. Reg. 18,052, 18,078 (Mar. 26, 2012) (screening threshold of 20).

The vast majority of similarly situated states have adopted screening threshold of 10 or higher. Such a threshold is consistent with EPA's BART Guidelines,[19] which provide:

> Based on our analyses, we believe that a state that has established 0.5 dv as a contribution threshold could reasonably exempt from the BART review process sources that emit less than 500 tons per year of NO—T2X or SO—T22 (or combined NO—T2X and SO—T22), as long as these sources are located more than 50 kilometers from any Class I area; and sources that emit less than 1000 tons per year of NO—T2X or SO—T22 (or combined NO—T2X and SO—T22) that are located more than 100 kilometers from any Class I area."

40 C.F.R. 51, appendix Y, section III, How to Identify Sources "Subject to BART." According to the BART Guidelines, therefore, a facility with minimal impacts such as these can reasonably be excluded from the regional haze program. As EPA explained in another final regional haze rule,

[19] Although the BART Guidelines are not binding in setting reasonable progress requirements, the BART Guidelines nonetheless provide useful precedent.

"[t]he values described [in the BART Guidelines] equate to a Q/D of 10." 82 Fed. Reg. at 17,955 n.53.

Had New Mexico adopted such a threshold, based on review of the most recent Q/d calculations, presented above, at least two of the three the Enterprise facilities (Chaco and South Carlsbad) should have screened out of further evaluation. For this reason alone, NMED should revise the Draft SIP to impose no additional control requirements for Chaco and South Carlsbad on this basis.

NMED has not offered a valid rationale for adopting such a low screening threshold. The explanation contained in the Draft SIP is that the threshold was intended:

> to capture 80% of the total NOx and SO_2 emissions from all New Mexico Title V facilities combined. NMED and EHD chose this 80% threshold based on guidance in the WRAP Source Selection Protocol. The Protocol noted draft guidance from EPA recommending an 80% threshold applied to emissions from all stationary sources.

Draft SIP at 92 (citation omitted). The draft guidance recommending an 80% threshold was never adopted by EPA. EPA instead issued the 2019 Guidance, which did not adopt the 80% threshold. Accordingly, NMED has adopted an extreme outlier screening threshold on the basis of guidance that was never adopted as formal EPA policy.

NMED should withdraw the Draft SIP and apply a more reasonable screening threshold, consistent with the actions of its sister states. It should further revise the Draft SIP to recognize that the visibility impacts of the Enterprise facilities are too small to justify imposing additional controls and are indeed, small enough to reasonably be screened out from a four-factor assessment.

VIII. NMED Has Failed to Adequately Consider Each of the Four Factors.

Under the CAA, states must consider four factors to determine reasonable progress: "the costs of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements." 42 U.S.C. § 7491(g)(1). Rather than fully consider each of the four factors, NMED has focused almost exclusively on cost, contrary to the CAA. The Draft SIP explains, "[c]ost effectiveness was the predominant factor in NMED's decision-making regarding necessary control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations." Draft SIP at 104.

Although states have considerable discretion as to how they weigh the four statutory reasonable progress factors, states must, at a minimum, give reasonable consideration to each one. *See Nat'l Parks Conservation Ass'n v. McCarthy*, 816 F.3d 989, 992 (8th Cir. 2016) (states "must consider four factors").

NMED has not considered the disbenefits of SCR. Specifically, in evaluating SCR or any other control, the state must take into account "the energy and nonair quality environmental impacts of compliance" to satisfy the CAA's requirements. Operation of SCR will have at least four such impacts.

First, a disbenefit of SCR is ammonia ("NH_3") emissions. Based on approximate exhaust rates for the 8 Enterprise turbines for which NMED has proposed to require SCR, and an estimated 10 ppmv NH_3 slip, aggregate annual NH_3 emissions would be approximately 196 tons assuming no restriction in operating hours.

NH_3 Emissions (Annual)

Facility	Estimated NH_3 Emissions
Blanco	86.6 tons
Chaco	87.6 tons
S. Carlsbad	21.8 tons

Emissions of ammonia have a range of environmental impacts. *See generally* U.S. EPA. Integrated Science Assessment (ISA) for Oxides of Nitrogen, Oxides of Sulfur and Particulate Matter Ecological Criteria (Final Report, 2020). NMED has not considered this disbenefit.

Second, the SCR system will involve the use of hazardous materials. SCR can use either aqueous or anhydrous ammonia for the reduction reaction. Anhydrous ammonia is classified as a hazardous material and often requires special permits as well as additional procedures for transportation, handling and storage. Aqueous ammonia, on the other hand, requires more storage capacity than anhydrous ammonia. Both pose environmental and safety risks. Again, NMED has not considered this.

Third, operation of SCR requires power. Due to the limited amount of time to evaluate SCR as a control option for the Enterprise facilities, a feasibility and constructability evaluation has not been completed at the time of submittal. It is therefore unknown if existing electrical power is sufficient or if upgrading or adding electrical infrastructure would be required. NMED has not considered these energy impacts either.

Fourth, operation of SCR could impact engine performance by creating additional working load on the engine. A detailed engineering study could not be performed in the limited time available for public comment. It is therefore not known issue will impact the ability of the Enterprise facilities to meet commercial throughput requirements. This is also an energy impact that NMED is obligated to consider.

Before NMED can lawfully propose its reasonable progress and related emission control determinations, it must present an assessment of each of the four factors evaluating the use of the controls under consideration. NMED has not done that in support of its proposed SCR requirements for the Enterprise facilities. A proper and complete evaluation of "the energy and nonair quality environmental impacts of compliance" would, moreover, provide further support

for the conclusion that SCR is not needed to achieve reasonable progress and that the existing controls at the Enterprise facilities ensure that reasonable progress will be achieved during the second planning period of the regional haze program.

IX. NMED Has Unreasonably Concluded SCR Is Technically Feasible.

According to EPA's 2019 Guidance, "[t]he first step in characterizing control measures for a source is the identification of technically feasible control measures for those pollutants that contribute to visibility impairment." 2019 Guidance at 28. EPA's regulatory BART Guidelines for the regional haze program provides further information on the methodology for assessing control to address visibility. In the BART Guidelines, EPA explained:

> You should clearly document a demonstration of technical infeasibility and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. You may then eliminate such technically infeasible control options from further consideration….
>
> Alternatively, a demonstration of technical infeasibility may involve a showing that there are unresolvable technical difficulties with applying the control to the source (e.g., size of the unit, location of the proposed site, or operating problems related to specific circumstances of the source).

Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations, 66 FR 38108, 38,123-24 (July 20, 2001).

During development of the Draft SIP, Enterprise demonstrated to NMED that SCR was not a technically feasible control for the Enterprise facilities. Enterprise communicated to NMED that it had eliminated consideration of SCR as a feasible technology due to the current configuration and available space.[20] Enterprise provided vendor-supplied SCR dimensions as CBI to NMED in support of that assessment.[21] Maps were also provided in this response that overlayed the area required for SCR showing existing facility infrastructure.

NMED has not explained its reason for changing course with respect to the technical feasibility of SCR for the Enterprise facilities. All that NMED says in this regard is the following:

[20] *See* Draft SIP, App. D at 481-82, 494-502, 574, 589-598, 639, 651-661 (Various Enterprise four-factor analysis submittals).

[21] *Id*. (providing CBI materials to NMED).

> Enterprise asserted that limited physical space precludes the option of installing SCR and provided an aerial image with measurement overlays to support this assertion. However, the image provided suggests there is physical space for SCR if building modifications are made.

Draft SIP, App. C at 80. This minimal level of assessment is not sufficient to serve as a basis for finding that SCR is technically feasible. NMED must revise the Draft SIP to reflect this reality.

X. New Mexico's Cost Evaluation for the Enterprise Facilities Is Substantially Flawed.

To support its proposed control requirements for the Enterprise facilities, NMED focused predominately on costs. Draft SIP at 102 ("To characterize the cost of compliance, which was the predominant factor in NMED's decision-making regarding control measures…."). NMED considered a single cost metric: "cost effectiveness of each control, expressed in terms of cost per ton of emissions reduced." *Id*.

The regional haze program is intended to evaluate real-world, site-specific costs. NMED says that it made use of such information in a limited fashion:

> NMED utilized source-specific cost estimates provided by the facilities in its calculations whenever possible. In cases where facilities failed to provide source-specific cost estimates or NMED found estimates provided by facilities to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including -four-factor analyses developed for similar facilities in New Mexico and other states, to estimate costs.

Id. There are substantial flaws in NMED's consideration of costs that necessitate reevaluation of and modifications to the Draft SIP's proposed control requirements for the Enterprise facilities.

A. NMED Has Not Considered Relevant Cost Metrics.

NMED has only considered cost-effectiveness on a simple dollar-per-ton basis. Such limited consideration does not fully evaluate costs and has resulted in Draft SIP requirements that go beyond what is needed to make reasonable progress. In the body of the Draft SIP, for instance, NMED presents only $/ton cost-effectiveness values for SCR. Draft SIP at 114-118. Appendix C, which contains additional narrative explaining NMED's four-factor analysis confirms that the $/ton metric was the only manner in which NMED considered costs. Draft SIP, App. C, at 68-91.

According to EPA's 2019 Guidance, a cost assessment in furtherance of a reasonable progress assessment "will typically produce estimated values of capital costs, annual operating and maintenance costs, annualized costs, and cost per ton of emission reductions, as well as

multiple values for daily visibility benefits." 2019 Guidance at 38. NMED has calculated annualized costs, but does not appear to have considered them. NMED has not considered a $-per-deciview or dollar-per-inverse megameter metric at all. These factors have been determinative in the regional haze proceedings of other states.

- Approval, Disapproval and Promulgation of Implementation Plans; State of Nebraska; Regional Haze State Implementation Plan; Federal Implementation Plan for Best Available Retrofit Technology Determination, 77 Fed. Reg. 40,150, 40,151, 40,156 (July 6, 2012) (EPA partially disapproving Nebraska's SIP after recalculating Nebraska's cost effectiveness analysis for BART using $/dv. Additionally, EPA defended its use of $/dv in response to a comment: "We believe that dollars per deciview is one of several metrics that can be used to analyze cost of visibility improvement, and reaffirm our position that the calculation is more meaningful if cumulative visibility benefits are accounted for.")

- Environmental Protection Agency: Rules and Regulations: Approval and Promulgation of Implementation Plans; State of Oregon; Regional Haze State Implementation Plan and Interstate Transport Plan, 76 Fed. Reg. 38997, 38999 (July 5, 2011) (EPA approving and promulgating Ohio's Regional Haze SIP for the first implementation period based on a dollars/dv threshold of $10 million per deciview; the EPA responded to a comment challenging the threshold by stating that the threshold was "consistent with EPA's review of dollars/dv cost effectiveness data…").

NMED's failure to consider cost metrics in addition to its dollar-per-ton calculations has left NMED with an incomplete picture of the costs of the controls it has proposed. New Mexico must further evaluate all potentially informative cost metrics to ensure that the state has met its obligation to weigh the four factors in determining reasonable progress. Failure to consider this information—which Congress intended the states to take into account—is arbitrary and capricious. *See Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43, (1983).

B. NMED's Cost-Estimates Are Unrealistic and Result in Unreasonable Control Determinations for the Enterprise Facilities.

NMED's assessment of the costs of SCR is incomplete, lacks site-specific information, and understates the costs associated with this control option. For each of the Enterprise facilities, the NMED spreadsheet presenting its SCR cost assessment indicates that NMED relied on default values from EPA's Control Cost Manual and its SCR cost calculation tool. Draft SIP, App. D at 455, 460 (Blanco), 536, 540 (Chaco), 622 (South Carlsbad).

Because Enterprise and NMED had previously concluded that SCR was not technically feasible at the Enterprise facilities due to space constraints, Enterprise did not seek vendor quotes or other information prior to release of the Draft SIP. Enterprise maintains that the site-specific

impediments to construction of SCR should be considered sufficiently onerous to render SCR technically infeasible at the Enterprise facility sites.

In the short time provided for public comment on the Draft SIP, Enterprise has not been able to develop the sort of detailed engineering studies that would be needed to fully assess the true costs of installing and operating SCR at the Enterprise facilities. Such information is needed for a true and accurate cost assessment. Accordingly, NMED should pause its efforts to seek approval of the Draft SIP and ensure that an adequate cost assessment, including site-specific information and vendor quotes, if available, is included in the record and comprises the basis for the SIP's requirements. Proceeding on the basis of NMED's more generic cost assessment when better data could have been obtained is arbitrary and capricious. *Conservation Cong. v. Finley*, 774 F.3d 611, 620 (9th Cir. 2014) ("Agencies 'must support their conclusions with accurate and reliable data'"). If Enterprise is able to obtain additional information further characterizing SCR costs, we will provide it to NMED as expeditiously as possible.

In the time provided, Enterprise has obtained two preliminary vendor quotes that demonstrate the values NMED has relied on are unrealistic. It is first important to emphasize that the quotes Enterprise has received significantly understate likely actual costs. Because of limited time, these quotes were developed without taking into account factors that will significantly impact costs:

1) No SCR feasibility or constructability walk-downs were performed to prepare these estimates.
2) Costs assume no relocations of existing infrastructure would be required; however, as explained further below, substantial relocation and additional construction will be required.
3) Costs are not based on detailed engineering studies.
4) The quotes assume sufficient electricity is available and do not include costs associated with upgrading or adding electrical infrastructure.

Even with these limitations, the vendor quotes indicate that NMED's cost estimates are too low.

Facility	Unit No.	Unit Type	NMED's Proposed NOx Control Measure	NMED's Total Capital Investment Estimate	NMED Cost Effectiveness	Enterprise Capital Investment Estimate	Enterprise Cost Effectiveness (Using NMED Methodology)
	35	Solar Mars T-15000	SCR (90% Reduction)	$5.3 MM	$9,000/ton	$6.8 MM	$10,107/ton
	36	Solar Mars T-15000	SCR (90% Reduction)	$5.3 MM	$9,000/ton	$6.8 MM	$10,713/ton
	37	Solar Mars T-15000	SCR (90% Reduction)	$5.3 MM	$10,000/ton	$6.8 MM	$12,062/ton

South Carlsbad Compressor Station	1	Solar Centaur T-4700	SCR (90% Reduction)	$2.5 MM	$5,000/ton	$7.2 MM	$13,617/ton
	2	Solar Centaur T-4700	SCR (90% Reduction)	$2.5 MM	$5,000/ton	$7.2 MM	$13,670/ton

Thus, even using marginally more accurate cost information substantially affects the outcome of a cost-effectiveness analysis. Without accounting for the complications and additional costs needed to address relocation of existing infrastructure and adequate power supplies, preliminary vendor information provided to Enterprise indicates that NMED has generally underestimated costs, in some cases substantially. Indeed, Enterprise's more accurate cost information establishes clearly that three of the units at Chaco and both units at South Carlsbad would exceed NMED's threshold for cost-effectiveness, even based on incomplete cost data. Enterprise is working to develop additional, more complete cost data for al of the Enterprise facilities and will seek to supplement the record as appropriate.

At least two additional factors excluded from NMED's and Enterprise's cost information will further increase costs significantly: (1) the costs associated with site-specific retrofit complications; (2) the use of an unsupported 90% NOx removal efficiency assumption.

First, costs associated with retrofitting the Enterprise facilities, including moving existing structures and equipment, will considerably affect cost-effectiveness. NMED explains that it attempted to account for the additional costs associated with retrofit complexity at the Enterprise facility sites by using a retrofit factor in EPA's cost calculation tool:

> A retrofit factor of 1.1 was used in the EPA SCR Tool to account for the additional capital costs anticipated to create physical space for the SCR system. This factor was selected based on Enterprise's recurring assertion that the current layout of the existing building cannot accommodate the physical space needed for SCR. Aerial photos provided by Enterprise suggest there is space for SCR if building modifications are made[.]

Draft SIP, App. D at 455. There is no explanation in the Draft SIP, however, as to how this factor affected costs or why it was the appropriate value to select. According to NMED documentation, EPA's SCR cost tool suggests a range of retrofit factors of "between 0.8 and 1.5 based on the level of difficulty" with a value of 1 being "for projects of average retrofit difficulty." *See id*. at 463. At the very least, to provide adequate support for its Draft SIP, NMED must explain why it has selected its chosen retrofit factor and why its choice is reasonable. A full analysis is likely to find that this figure does not fully capture the costs likely to be incurred to install and operate SCR.

Second, both the NMED and Enterprise cost effectiveness values are also overinflated due to the assumption by NMED, which Enterprise replicated in its assessment of the vendor information, that SCR can achieve a 90 percent removal efficiency at the Enterprise facilities.

The basis for that assumption appears to be that 90 percent is a default value in EPA's SCR cost tool. Draft SIP, App. D at 460. The Draft SIP provides no other explanation than the value is an assumption: "Emissions limitations for selective catalytic reduction are based on current actual emissions and an assumed 90% control efficiency." Draft SIP at 140.

This assumption may be appropriate for some industries under certain conditions, but it is not likely applicable to the Enterprise facilities. As explained in the attached letter from Solar Turbines to Enterprise, a much lower removal efficiency is more likely to apply to at least some the Enterprise units. A 60% to 80% NOx reduction may be a more realistic range of NOx reduction achievable with SCRs placed on certain Enterprise units.[22]

The reduction efficiencies Solar Turbines supports are consistent with EPA's analysis. In its AP-42: Compilation of Air Emissions Factors from Stationary Sources, EPA explains that "[t]he removal efficiency of an SCR system in good working order is typically from 65 to 90 percent." AP-42 at § 3.1.4.3. NMED should, at the least, assume a more realistic removal efficiency. NMED should further conduct a full assessment of removal-efficiency achievability for the Enterprise facilities. Such a change will further increase the cost-effectiveness values.

Enterprise believes that the best available information indicates that SCR is not cost-effective. Just as importantly, however, NMED has not made an adequate demonstration that SCR is cost-effective. Because that burden falls upon the state, NMED should withdraw its Draft SIP, conduct a more fulsome cost analysis, consistent with these comments, and propose a substantially revised Draft SIP.

C. NMED's Cost-Estimates Threshold is Too High.

NMED has adopted a "cost effectiveness threshold value (CETV) to remove control measures deemed not cost-effective from further consideration." Draft SIP at 102. NMED set its CETV at $10,000/ton NOx removed. *Id*. This threshold is too high and an outlier among states.

- Partial Approval and Disapproval of Air Quality Implementation Plans; Arizona; Regional Haze State Implementation Plan for the Second Implementation Period and Prong 4 (Visibility) for the 2015 Ozone and 2012 Particulate Matter Standards, 89 Fed. Reg. 47,398, 47,429 (May 31, 2024) (Cost-effectiveness threshold of $6,500/ton for point sources).
- Disapproval and Promulgation of Air Quality Implementation Plans; Texas and Oklahoma; Regional Haze State Implementation Plans; Federal Implementation Plan for Regional Haze; Completion of Remand, 88 Fed. Reg. 48,152, 48,167 (July 26, 2023) (cost-effectiveness threshold of $2,700/ton).

[22] Letter from Solar Turbines, Re: Solar Compressor Sets - NOx Reductions per NM Regional Haze Rule Requirements (Sept. 9, 2024) (Attachment C).

- Approval, Disapproval and Promulgation of Implementation Plans; State of Nebraska; Regional Haze State Implementation Plan; Federal Implementation Plan for Best Available Retrofit Technology Determination, 77 Fed. Reg. 40,150, 40,159 (July 6, 2012) (cost effectiveness threshold of $5,000 incremental cost per ton).

In addition to relying on much lower cost-effectiveness thresholds, several of these states failed, in EPA's view, to adequately support their chosen cost-effectiveness thresholds. *See, e.g.*, *id*. NMED has likewise failed to explain why its threshold is reasonable.

In one recent rulemaking action addressing the regional haze SIP for Missouri, EPA reviewed cost-effectiveness thresholds used in the regional haze context. In that action, EPA notes that Missouri selected cost-effectiveness thresholds of $3,658 per ton for SO_2 controls and $5,370 per ton for NOx controls. Air Plan Partial Approval and Partial Disapproval; Missouri; Regional Haze, 89 FR 55140, 55154 (July 3, 2024). Although EPA proposed to find those values were too low, EPA instead found costs in the range of $5,000/ton to $6,000/ton for SO_2 control would be more appropriate. *Id*.

EPA further explained that the regional planning organization for Missouri had recommended cost-effectiveness thresholds in a range from $4,000 to $5,000/ton (in 2005 dollars) which becomes $6,060 to $7,600/ton in 2021 dollars. *Id*. EPA provided another example with its own cost-effectiveness threshold of $4,200 to $5,100/ton range (escalated to 2020 dollars) for a Texas regional haze federal implementation plan. EPA further noted that, in 2021 dollars, this range is $5,300/ton to $6,500/ton. *Id*.

The one thing all of these values have in common is that they are much lower than NMED's cost-effectiveness threshold. If NMED were to adopt a threshold more in line with the practice of other states and EPA itself, it is likely that none of the Enterprise facilities would be deemed to have additional cost-effective control options, and SCR would certainly not be deemed cost-effective.

D. NMED Should Provide Enterprise an Opportunity to Address Specific Cost Items.

In the Draft SIP, NMED says that it excluded certain cost items provided by Enterprise or relied on default values where information was not available:

> In cases where Enterprise failed to provide source-specific cost estimates or NMED found estimates provided by Enterprise to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs.

Draft SIP, App. C at 69. Enterprise believes the information it has provided is reliable, and requests that NMED identify gaps in information that it deems crucial or that might otherwise address any shortcomings NMED perceives with the information Enterprise has provided. Enterprise will work with the Department to provide the more reliable possible information.

XI. In the Alternative, NMED Should Provide Enterprise With Additional Compliance Flexibility.

As drafted, NMED's proposed regulation would impose unit-by-unit emission rate limits for each of the Enterprise facilities. NMED can achieve the same emission reductions and the same improvements in visibility (minimal as they may be) while providing for greater operational flexibility for the Enterprise facilities.

Specifically, if NMED proceeds to seek final approval of its Draft SIP without changing course on requiring emission limits based on SCR for the Enterprise facilities—which it should not—Enterprise requests that NMED allow for facility-wide averaging. Allowing this additional compliance flexibility will ensure that each facility meets an overall emission rate limit while allowing Enterprise to operate the respective emissions units at each facility in the most efficient manner possible.

Allowing for averaging in this manner is fully consistent with the state's legal authority under the regional haze program and similar approaches have been adopted to address reasonable progress requirements in the past.

- Approval and Promulgation of Air Quality Implementation Plans; New Hampshire; Regional Haze, 77 Fed. Reg. 11,809 11,818 (Feb. 28, 2012) (placing two unit within a regulatory "bubble" for compliance purposes).

- Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans, 77 Fed. Reg. 72,512, 72,527 (Dec. 5, 2012) (applying a compliance "bubble" across multiple units)

Enterprise further requests that NMED reevaluate the emission rate limits contained in the Companion Rule. Those limits are likely too stringent even with installation of SCR, although Enterprise will continue to evaluate this issue. Emission rate limits in the SIP should instead be based on the existing controls at the Enterprise facilities.

CONCLUSION

For all of the foregoing reasons, NMED's Draft SIP would impose unwarranted emission control requirements on Enterprise's facilities. The Draft SIP's requirements are based on a flawed cost assessment and a failure of the Department to fully consider the four reasonable progress factors and the visibility implications of its proposed emission control requirements. NMED should withdraw the Draft SIP and propose regional haze requirements for the Enterprise facilities consistent with the site-specific analysis Enterprise has provided and the CAA's goal that states make reasonable progress toward the national visibility goal.

Should you have any questions regarding this submittal, please contact Tucker Jacobson at (713) 381-4313 (wtjacobson@eprod.com) or Bradley Cooley at (713) 381-5828 (bjcooley@eprod.com).

Sincerely,



Aaron M. Flynn
Counsel for Enterprise Field Services

Attachment A

ENTERPRISE PRODUCTS PARTNERS L.P.

REGIONAL HAZE PLANNING MEETING

February 19, 2020

EPD
LISTED
NYSE

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AGENDA

- NMED Regional Haze Planning Status and Process
- Questions on Four-Factor Analysis Reports
  - South Carlsbad Compressor Station
  - Blanco C & D Compressor Station
  - Chaco Gas Plant
- Impact to Regional Haze

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2016 REGIONAL HAZE RULE IMPACTED FACILITIES

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

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SOUTH CARLSBAD COMPRESSOR STATION



South Carlsbad Compressor Station

- 16.2 miles from Carlsbad Caverns National Park

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BLANCO C & D COMPRESSOR STATION
CHACO GAS PLANT



Blanco C & D Compressor Station

- 39.5 miles to Mesa Verde National Park

Chaco Gas Plant

- 49.5 miles to Mesa Verde National Park

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EPA MODELING – CARLSBAD CAVERNS

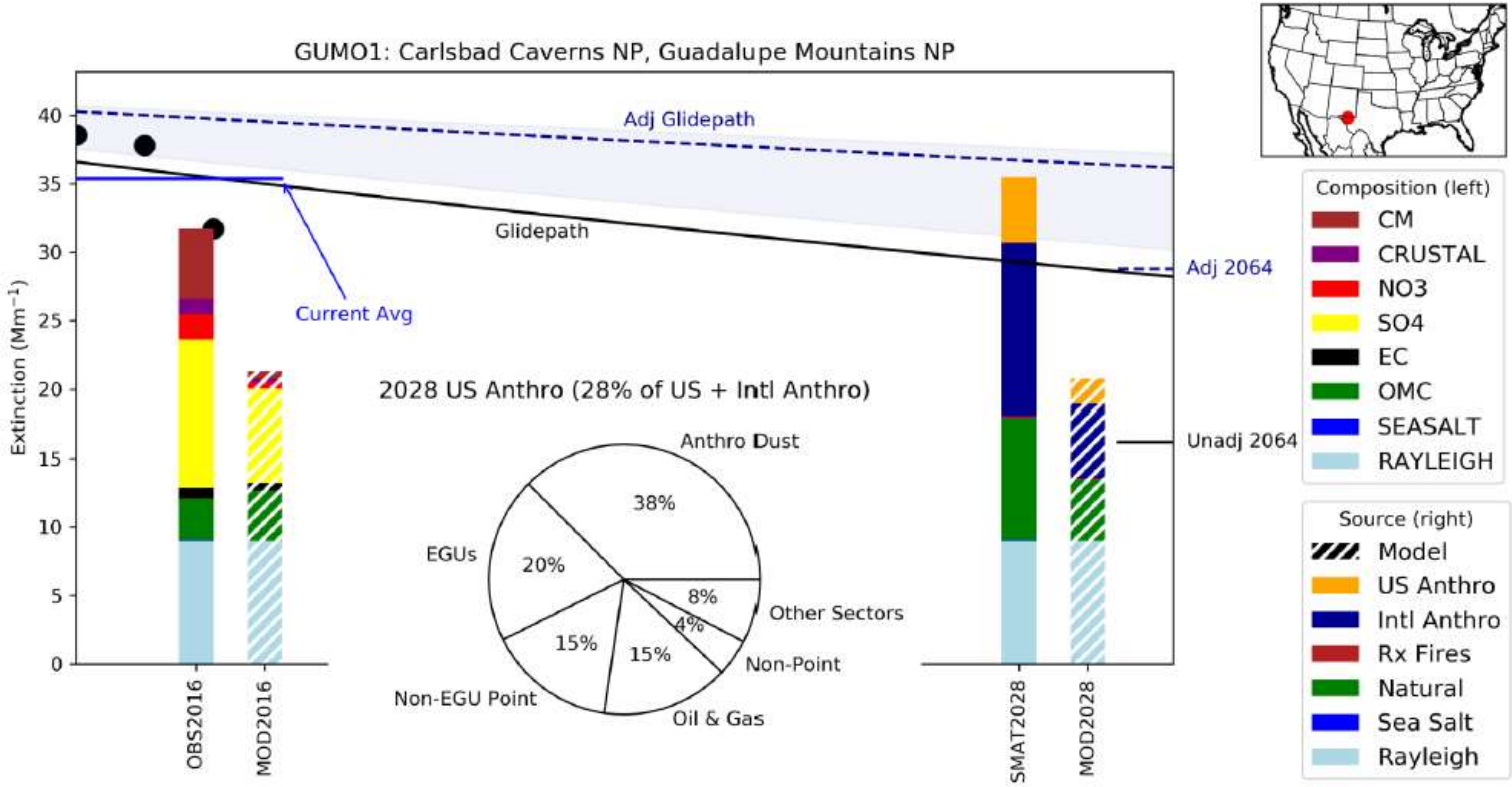


Figure 34: 2014-2017 IMPROVE observations, 2016 CAMx model predictions, 2028 modeled projection, and 2028 sector contributions at GUMO1. Used for Class I areas: Carlsbad Caverns NP, Guadalupe Mountains NP.

Class I Area	2028 Projected 20% most impaired days (dv)	2028 Unadjusted Glidepath 20% most impaired days (dv)	2028 Default Adjusted Glidepath (dv)	2028 Minimum Alternative Adjusted Glidepath (dv)	2028 Maximum Alternative Adjusted Glidepath (dv)
Carlsbad	**12.48**	**10.69**	**12.99**	**11.32**	**13.25**

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EPA MODELING – MESA VERDE

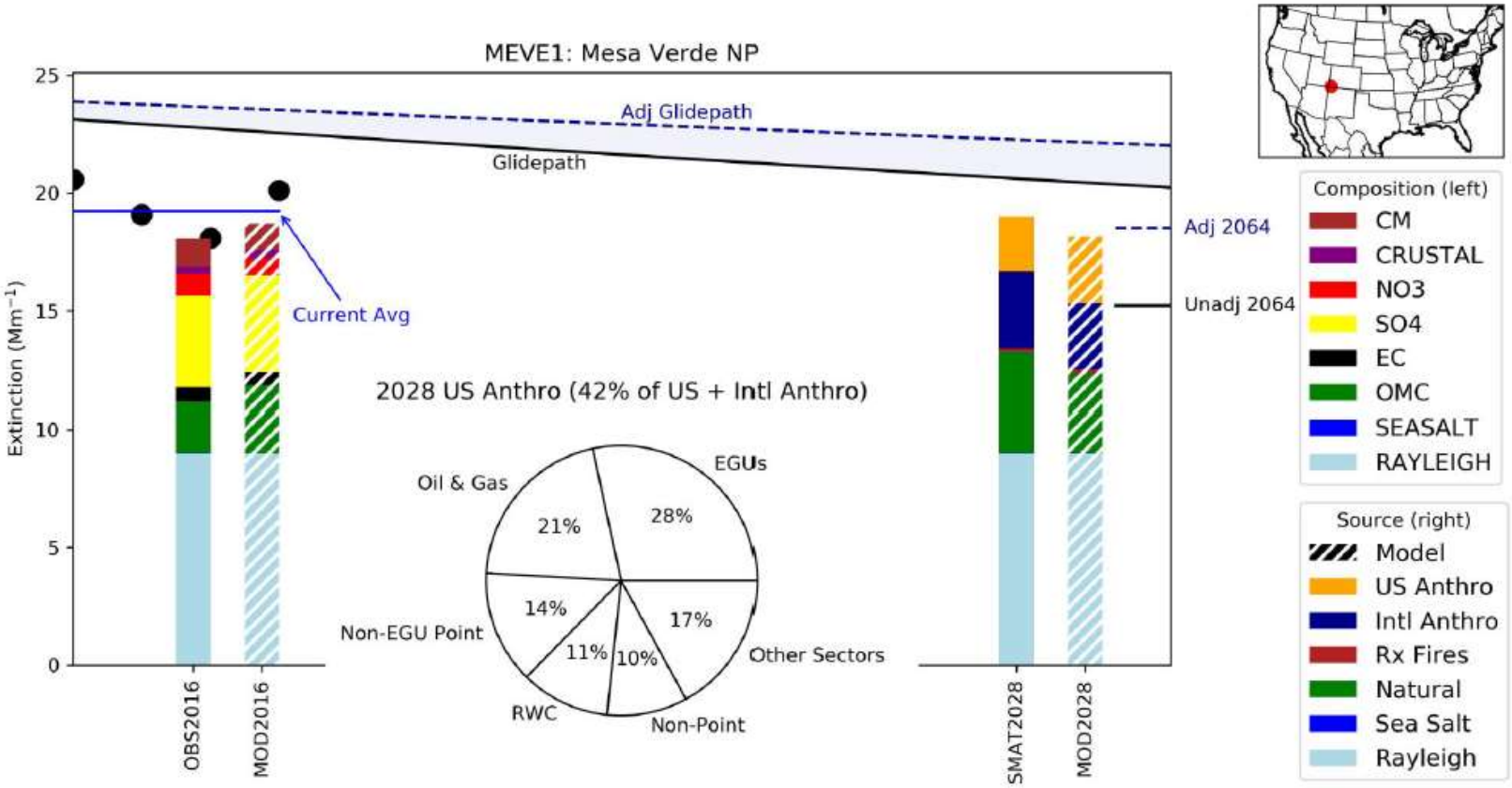


Figure 52: 2014-2017 IMPROVE observations, 2016 CAMx model predictions, 2028 modeled projection, and 2028 sector contributions at MEVE1. Used for Class I areas: Mesa Verde NP.

Class I Area	2028 Projected 20% most impaired days (dv)	2028 Unadjusted Glidepath 20% most impaired days (dv)	2028 Default Adjusted Glidepath (dv)	2028 Minimum Alternative Adjusted Glidepath (dv)	2028 Maximum Alternative Adjusted Glidepath (dv)
Mesa Verde	**6.3**	**7.22**	**8.00**	**7.24**	**8.03**

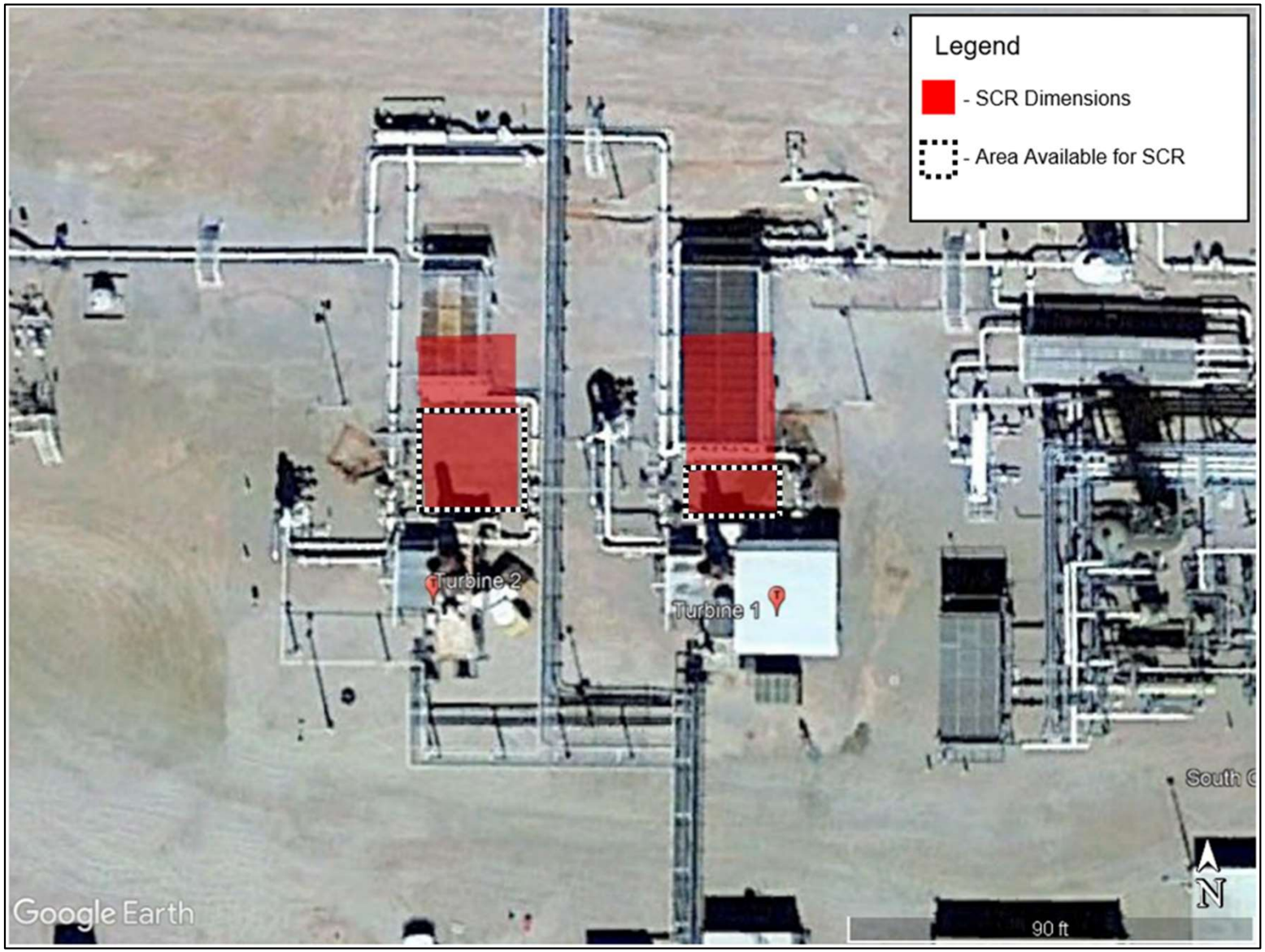
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COST EFFECTIVENESS SUMMARY

Facility	Combustion Source	Unit No.	2016 NOx Emissions (tpy)	NOx Reduction Technology	2016 NOx Emissions w/ Control (tpy)	Cost Effectiveness ($/ton removed)
South Carlsbad Compressor Station	Solar Centaur T4702	1	32.42	SoloNOx (25 ppm)	11.64	$ 8,583.57
	Solar Centaur T4702	2	40.8	SoloNOx (25 ppm)	13.89	$ 6,629.15
Blanco C & D Compressor Station	GE Frame 5	T-C01	158.6	Water Injection (15% Reduction)	134.81	$ 79,086.07
				Steam Injection (15% Reduction)		$ 110,101.19
				Water Injection (42 ppm)	115.44	$ 43,598.09
				Steam Injection (42 ppm)		$ 60,695.91
	GE Frame 5	T-C02	219.26	Water Injection (15% Reduction)	186.37	$ 57,206.25
				Steam Injection (15% Reduction)		$ 79,640.77
				Water Injection (42 ppm)	110.68	$ 17,328.49
				Steam Injection (42 ppm)		$ 24,124.20
	GE M5322B	T-D01	197.37	Dry Low NOx (DLN) (35 ppm)	106.33	$ 9,934.37
				Water Injection (15% Reduction)	167.76	$ 63,551.77
				Steam Injection (15% Reduction)		$ 88,474.82
				Water Injection (42 ppm)	127.59	$ 26,965.69
				Steam Injection (42 ppm)		$ 37,540.80
Chaco Gas Plant	Clark TLA-10	12	107.7	NOx reduction controls not evaluated based on technical infeasibility		
	Clark TLA-10	13	197.3			
	Clark TLA-10	14	189.2			
	GE Frame 5	17	126.82	Water Injection (15% Reduction)	107.80	$ 106,606.41
				Steam Injection (15% Reduction)		$ 148,511.84
	GE Frame 5	18	126.61	Water Injection (15% Reduction)	107.62	$ 106,784.35
				Steam Injection (15% Reduction)		$ 148,759.74
	Solar Mars T-15000	35	119.52	SoloNOx (15 ppm)	14.34	$ 6,800.13
	Solar Mars T-15000	36	117.84	SoloNOx (15 ppm)	14.52	$ 6,668.02
	Solar Mars T-15000	37	85.97	SoloNOx (15 ppm)	12.48	$ 9,434.46

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SOUTH CARLSBAD COMPRESSOR STATION

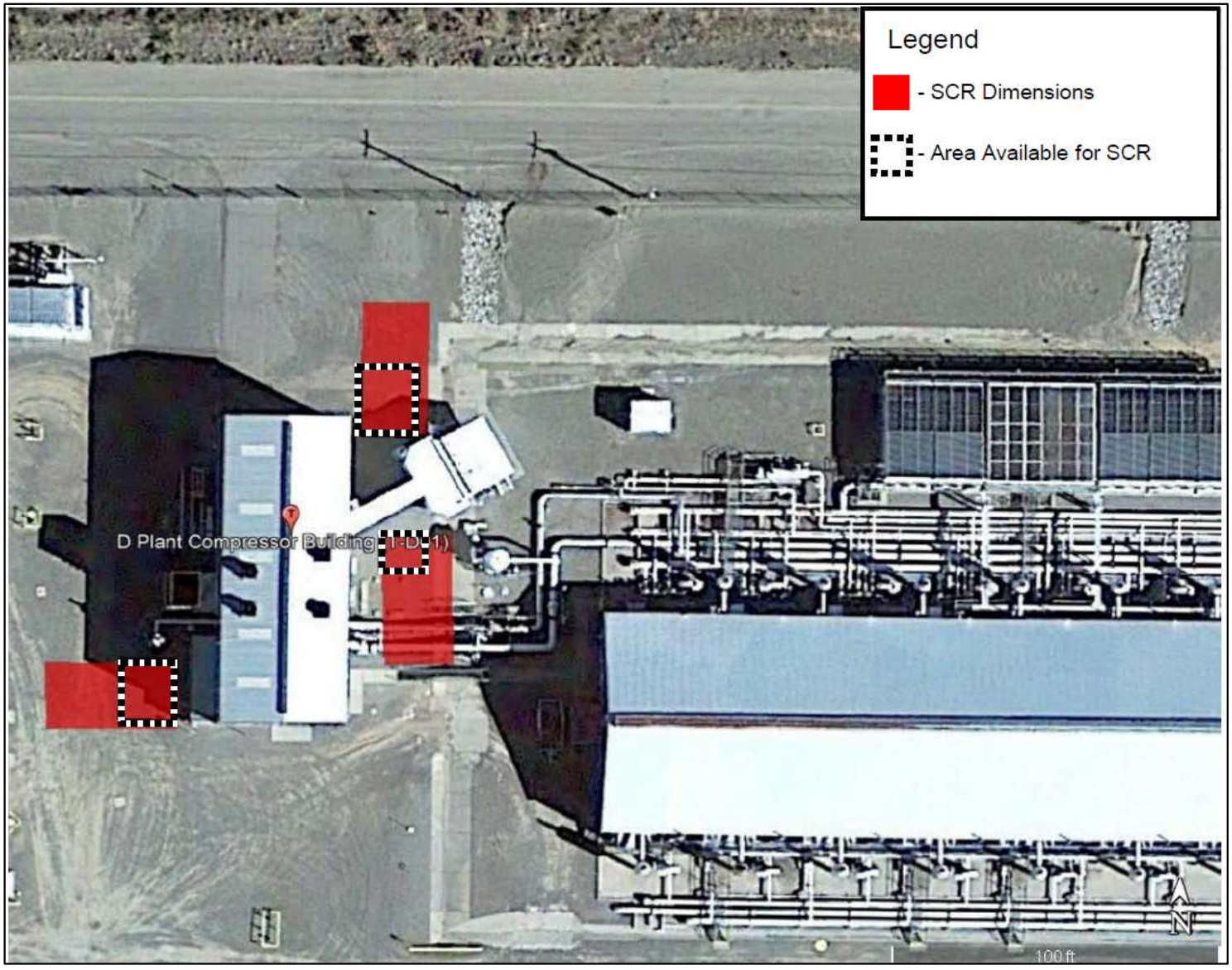


Solar Centaur T4702 Turbines (1 and 2)

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BLANCO C & D COMPRESSOR STATION

(D PLANT)

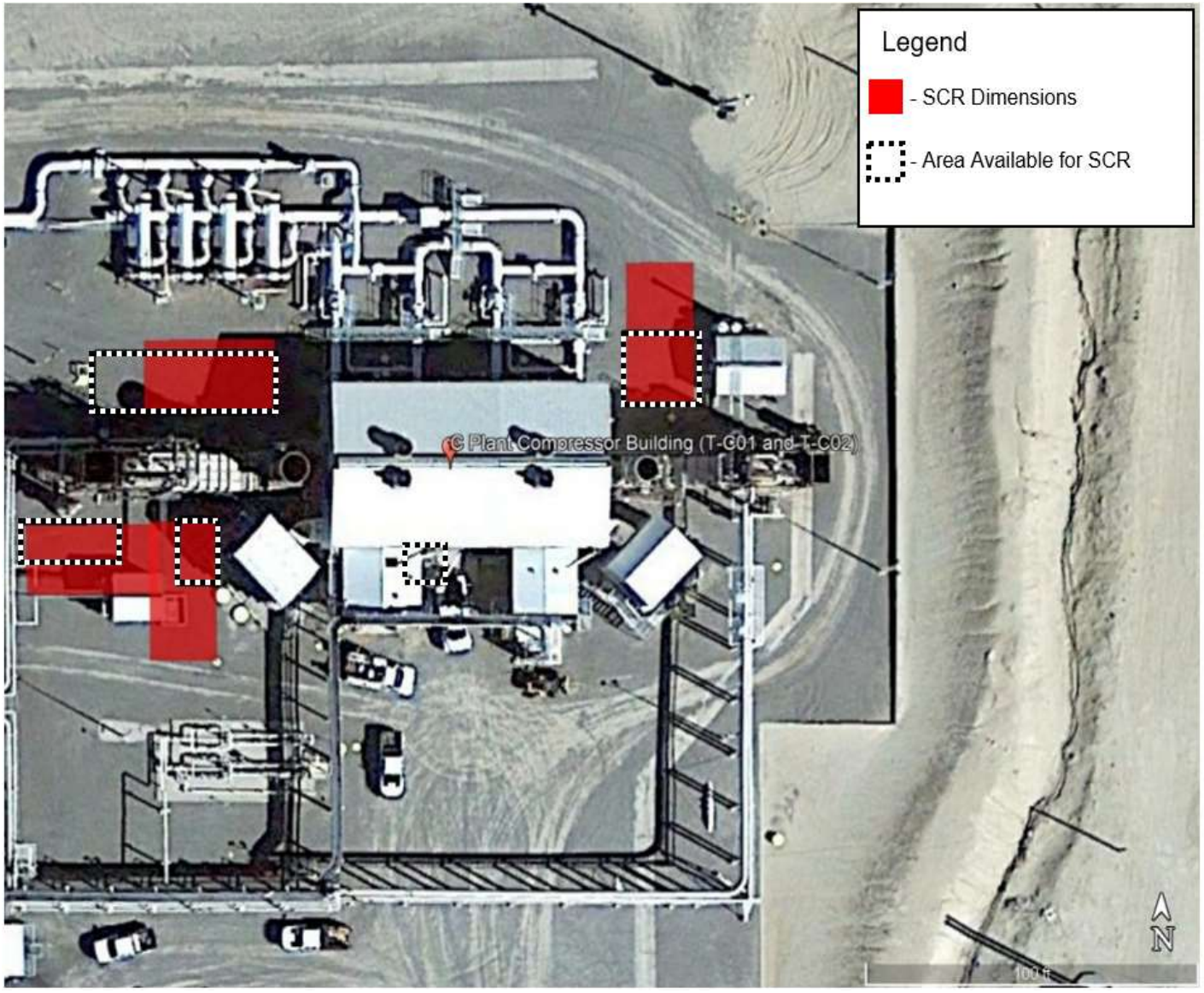


GE M5322B Turbine (T-D01)

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BLANCO C & D COMPRESSOR STATION

(C PLANT)



GE Frame 5 Turbines (T-C01 and T-C02)

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CHACO GAS PLANT



Clark TLA-10 Engines (12,13,14), GE Frame 5 Turbines (17,18), Solar Mars T-15000 Turbines (35,36,37)

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Attachment B

From:	Olson, Kirby, ENV
To:	Jacobson, Tucker
Cc:	Cooley, Bradley; Craft, Zachary; PKULKARNIE@eprod.com; Jones, Mark, ENV; Miller, Kenneth, ENV; Sanchez, Alex, ENV
Subject:	[EXTERNAL] Revised Regional haze cost evaluations for Blanco C&D and Chaco Gas Plant
Date:	Wednesday, December 20, 2023 10:54:16 AM
Attachments:	2023-12-19_Corrected Draft Final NMED Cost Evaluation_Enterprise - Blanco C and D Compressor Station.xlsx 2023-12-19_Corrected Draft Final NMED Cost Evaluation_Enterprise - Chaco Gas Plant.xlsx

[Use caution with links/attachments]

Dear Mr. Jacobson,

After sending you NMED's draft final cost evaluations for Enterprise Field Services, LLC's Blanco C&D Compressor Station, Chaco Gas Plant and South Carlsbad Compressor Station last Thursday (12/14), our Regional Haze planning team discovered a formula error in the following sheets:

- Sheet "Eval – EMD" of the Blanco C&D Compressor Station workbook, resulting in an incorrect 2023$ cost effectiveness value for Unit T-C02
- Sheet "EMD1" of the Chaco Gas Plant workbook, resulting in an incorrect 2023$ cost effectiveness value for Unit 18
- Sheet "EMD2" of the Chaco Gas Plant workbook, resulting in incorrect 2023$ cost effectiveness values for Units 36 and 37
- Sheet "EMD3" of the Chaco Gas Plant workbook, resulting in incorrect 2023$ cost effectiveness values for Units 13 and 14

The errors have been corrected in the attached workbooks. Please disregard the Blanco C&D Compressor Station and Chaco Gas Plant workbooks we provided last week and review the sheets in the attached, corrected versions instead. As a reminder, the deadline to submit review comments is Jan. 15, 2024.

Regards,
Kirby Olson

This email is intended to serve as general guidance and is in no way a formal statement of Department policy. Unique operating conditions may result in different determinations and may require a site specific analysis to accurately determine requirements and applicability.

Kirby Sue Olson, Ph.D.
Planning Section Chief
Air Quality Bureau
New Mexico Environment Department
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505
Phone: (505) 629-5107
Fax: (505) 476-4375

kirby.olson@env.nm.gov
https://www.env.nm.gov

"Science, Innovation, Collaboration, Compliance"

Facility Information

Enterprise - Blanco C & D	**Facility**
Two pre-June 1989 CTs, 22,280 HP each	**Units**
T-C01 and T-C02	**Unit IDs**
Water/Steam Injection	**Evaluated Pollution Control**
42.0	**Post-control Emissions Rate (ppmv**

Supporting Information

1999	Calendar year associated with cost e
22,280	Nameplate Capacity (hp/unit)

Economic Evaluation

Cost Component		**T-C01**
Purchased equipment costs ($)	PEC	$ 431,000
Other Direct Capital Costs 1 ($)	ODC	$ 243,975
Indirect Capital Costs ($)	IDC	$ 408,200
Total Capital Costs - Direct ($)	TCC	$ 1,083,175
Additional Capital ($)	AC	$ -
Total Capital Investment ($)	TCI	$ 1,083,175
Interest Rate (%)	R	10.50%
Useful Life (yr)	Y	15
Capital Recovery Factor	CRF	0.1352
Annualized Capital Costs ($/yr)	ACC	$ 146,497
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 294,000
Other Indirect Annual Costs ($/yr)	OAC	$ 43,327
Total Annualized Costs ($/yr)	TAC	$ 483,824
NOx Control Efficiency (%)	Eff	9%
Baseline Actual NOx Emissions (ton/yr)	BAE	139.7
Future Utilization Adjustment (%)	FUA	0%

Projected Actual Emissions (ton/yr)	PAE	139.7
Estimated Reductions (ton/yr)	ER	12.0
1999$ Cost Effectiveness ($/ton)	**CE1**	**$ 40,399**
Consumer Price Index Ratio	CPI	$ 1.83
2023$ Cost Effectiveness ($/ton)	**CE2**	**$ 73,962**

(A) Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, Nov 1999, Table A-4, 25
Note: Units T-C01 and T-C02 are ~ 16.6 MW (mechanical) units and thus reasonably similiar in size

d)

estimates (based on primary data source)

T-C02	Source
$ 431,000	(A)
$ 243,975	(A)
$ 408,200	(A)
$ 1,083,175	-
$ -	Not specified by Enterprise
$ 1,083,175	(A)
10.50%	Enterprise August 2023 FFA update
15	Enterprise initial (2019) FFA and August 2023 update
0.1352	-
$ 146,497	-
$ 294,000	(A)
$ 43,327	EPA Cost Manual, Section 2.6.5.8
$ 483,824	-
34%	-
195.1	CY 2018 emissions testing and average operating hours (2016-2
0%	Not specified by Enterprise

195.1	-
65.5	-
$ 7,384	-
$ 1.83	https://www.bls.gov/data/inflation_calculator.htm
$ 13,518	-

MW Class

to the 25 MW Class used in the analysis.

Methodology/Note
Total system cost
Taxes Freight and installation direct costs
Indirect installation and contingency
PEC + ODC + IDC
TCC + AC
Standard CRF calculation
TCI x CRF
Annual costs (does not include Capital Recovery)
4% of TCI
ACC + OMC + OAC
(Current actual - Post Control)/Current actual
021)

BAE x (1 + FUA)
PAE x Eff
TAC/ER

Based on CPI for All Urban Consumers: Refer to table in CPI Worksheet

CE1x CPI

Facility Information

Enterprise - Blanco C & D	**Facility**
Two pre-June 1989 CTs, 22,280 HP each	**Units**
T-C01 and T-C02	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
9.0	**Post-control Emissions Rate (ppmv**

Supporting Information

2020	Calendar year associated with cost e
22,280	Nameplate Capacity (hp/unit)

Economic Evaluation

Cost Component		**T-C01**
Purchased equipment costs ($)	PEC	$ -
Other Direct Capital Costs 1 ($)	ODC1	$ -
Other Direct Capital Costs 2 ($)	ODC2	$ -
Indirect Capital Costs ($)	IDC	$ -
Total Capital Costs - Direct ($)	TCC	$ -
Additional Capital ($)	AC	$ -
Total Capital Investment ($)	TCI	$ 53,873,040
Interest Rate (%)	R	10.50%
Useful Life (yr)	Y	30
Capital Recovery Factor	CRF	0.1105
Annualized Capital Costs ($/yr)	ACC	$ 5,954,505
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 46,465
Other Indirect Annual Costs ($/yr)	OAC	$ -
Total Annualized Costs ($/yr)	TAC	$ 6,000,971
NOx Control Efficiency (%)	Eff	80%
Baseline Actual NOx Emissions (ton/yr)	BAE	139.7

Future Utilization Adjustment (%)	FUA	0%
Projected Actual Emissions (ton/yr)	PAE	139.7
Estimated Reductions (ton/yr)	ER	112.4
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 53,405**
Consumer Price Index Ratio	CPI	$ 1.18
2023$ Cost Effectiveness ($/ton)	**CE2**	**$ 63,018**

d)

estimates (year not specified in submission)

T-C02	Source
$ -	Included in TCI
$ -	Included in TCI
$ -	Included in TCI
$ -	Included in TCI
$ -	Included in TCI
$ -	Included in TCI
$ 53,873,040	9/8/20 info from El Paso Natural Gas
10.50%	Enterprise August 2023 FFA update
30	ERG experience based on discussions with CT manufacturers
0.1105	-
$ 5,954,505	-
$ 46,465	Enterprise August 2023 FFA update (2023$ converted to 2020$
$ -	-
$ 6,000,971	-
86%	-
195.1	CY 2018 emissions testing and average operating hours (2016-2

0%	Not specified by Enterprise
195.1	-
167.3	-
$ 35,868	Cost info provided by EPNG on 9/8/20 so assumed costs are in
$ 1.18	https://www.bls.gov/data/inflation_calculator.htm
$ 42,324	-

Methodology/Note
All-in estimate ($/HP) x Maximum Power Output (HP)
Standard CRF calculation
TCI x CRF
Incremental overhaul costs for DLN retrofit
4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs a
ACC + OMC + OAC
(Current actual - Post Control)/Current actual
021)

BAE x (1 + FUA)
PAE x Eff
TAC/ER

Based on CPI for All Urban Consumers (July 2020 -> July 2023)

CE1 x CPI

ssociated with replacement with an equivalent/like-kind unit

Facility Information

Enterprise - Blanco C & D	**Facility**
Two pre-June 1989 CTs, 22,280 HP each	**Units**
T-C01 and T-C02	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (lb/hr)**

Additional Information

2023	Calendar year associated with cost e
22,280	Nameplate Capacity (hp/unit)

Economic Evaluation

Cost Component		**T-C01**
Purchased equipment costs ($)	PEC	$ -
Other Direct Capital Costs 1 ($)	ODC1	$ -
Other Direct Capital Costs 2 ($)	ODC2	$ -
Indirect Capital Costs ($)	IDC	$ -
Total Capital Costs - Direct ($)	TCC	$ 46,431,520
Additional Capital ($)	AC	$ -
Total Capital Investment ($)	TCI	$ 46,431,520
Interest Rate (%)	R	10.50%
Useful Life (yr)	Y	25
Capital Recovery Factor	CRF	0.114
Annualized Capital Costs ($/yr)	ACC	$ 5,313,127
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 4,485,294
Additional Electricity Demand ($/yr)	AED	$ 8,970,588
Associated non-electricity O&M ($/yr)	AOM	$ -
Annual Fuel Credit ($/yr)	AFC	$ (4,485,294)
Other Indirect Annual Costs ($/yr)	OAC	$ -
Total Annualized Costs ($/yr)	TAC	$ 9,798,421
NOx Control Efficiency (%)	Eff	100%

Baseline Actual NOx Emissions (ton/yr)	BAE	139.7
Future Utilization Adjustment (%)	FUA	0%
Projected Actual Emissions (ton/yr)	PAE	139.7
Estimated Reductions (ton/yr)	ER	139.7
2023$ Cost Effectiveness ($/ton)	**CE**	**$ 70,115**

estimates

T-C02	Source
$ -	Included in TCC
$ -	Included in TCC
$ -	Included in TCC
$ -	Included in TCC
$ 46,431,520	-
$ -	-
$ 46,431,520	-
10.50%	Enterprise Aug 2023 CBI update
25	Consistent with other FFAs
0.114	-
$ 5,313,127	-
$ 4,538,198	
$ 9,076,396	ERG calculation
$ -	Engineering judgement
$ (4,538,198)	ERG calculation
$ -	-
$ 9,851,325	-
100%	-

195.1	CY 2018 emissions testing and average operating hours (2016-2
0%	Not specified by Enterprise
195.1	-
195.1	-
$ 50,502	**-**

Methodology/Note
Enterprise provided a cost estimate for electrification using EPA Cost Control Manual Section 5.2, which pertains to acid gas scrubbers. As this is not applicable to replacement with EMD, a Total Capital Cost metric of $2,084 (2023$/hp) was calculated using detailed cost information provided by other facilities. The TCI figure assumes no costs associated with substation or distribution line upgrades. This assumption underestimates costs given that Enterprise indicated in its August 2023 update that utility infrastructure upgrades would be needed to support electrification at all three of its facilities.
TCC + AC
Standard CRF calculation
TCI x CRF
AED + AOM + AFC
Assumes units at 60% load, 95% efficiency and a $0.10/kWh price
Assumed to be negligible
Assumed equal to 50% of AED
4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs a
ACC + OMC + OAC
No emissions from EMD units

021)
BAE x (1 + FUA)
PAE x Eff
TAC/ER

ssociated with replacement with an equivalent/like-kind unit

Facility Information

Enterprise - Blanco C & D	**Facility**
Pre 1978 GE M5322B NG CT, 32,550 HP	**Units**
T-D01	**Unit IDs**
DLN	**Evaluated Pollution Control**
35.0	**Post-control Emissions Rate (ppmv**

Supporting Information

2023	Calendar year associated with cost e
32,550	Nameplate Capacity (hp/unit)

Economic Evaluation

Cost Component		**T-D01**
Purchased equipment costs ($)	PEC	$ -
Other Direct Capital Costs 1 ($)	ODC	$ -
Indirect Capital Costs ($)	IDC	$ -
Total Capital Costs - Direct ($)	TCC	$ -
Additional Capital ($)	AC	$ -
Total Capital Investment ($)	TCI	$ 9,114,000
Interest Rate (%)	R	10.50%
Useful Life (yr)	Y	20
Capital Recovery Factor	CRF	0.1215
Annualized Capital Costs ($/yr)	ACC	$ 1,107,290
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 54,829
Other Indirect Annual Costs ($/yr)	OAC	$ 364,560
Total Annualized Costs ($/yr)	TAC	$ 1,526,679
NOx Control Efficiency (%)	Eff	34%
Baseline Actual NOx Emissions (ton/yr)	BAE	131.6
Future Utilization Adjustment (%)	FUA	0%

Projected Actual Emissions (ton/yr)	PAE	131.6
Estimated Reductions (ton/yr)	ER	44.7
2023$ Cost Effectiveness ($/ton)	**CE**	**$ 34,129**

d)

estimates (year not specified in submission)

Source
Included in TCI
Included in TCI
Included in TCI
Included in TCI
Included in TCI
Enterprise August 2023 FFA Update
Enterprise August 2023 FFA Update
Enterprise initial (2019) FFA and August 2023 update
-
-
Enterprise August 2023 FFA Update
EPA Cost Manual, Section 2.6.5.8
-
-
CY 2018 emissions testing and average operating hours (2016-2
Not specified by Enterprise

-
-
-

Methodology/Note
All-in estimate ($/HP) x Maximum Power Output (HP)
Consistent with other FFAs
Standard CRF calculation
TCI x CRF
"Incremental overhaul costs"
4% of TCI
ACC + OMC + OAC
(Current actual - Post Control)/Current actual
021)

BAE x (1 + FUA)
PAE x Eff
TAC/ER

Facility Information

Enterprise - Blanco C & D	**Facility**
Pre 1978 GE M5322B NG CT, 32,550 HP	**Units**
T-D01	**Unit IDs**
Water/Steam Injection	**Evaluated Pollution Control**
42.0	**Post-control Emissions Rate (ppmv**

Supporting Information

1999	Calendar year associated with cost e
32,550	Nameplate Capacity (hp/unit)

Economic Evaluation

Cost Component		**T-D01**
Purchased equipment costs ($)	PEC	$ 431,000
Other Direct Capital Costs 1 ($)	ODC	$ 243,975
Indirect Capital Costs ($)	IDC	$ 408,200
Total Capital Costs - Direct ($)	TCC	$ 1,083,175
Additional Capital ($)	AC	$ -
Total Capital Investment ($)	TCI	$ 1,083,175
Interest Rate (%)	R	10.50%
Useful Life (yr)	Y	15
Capital Recovery Factor	CRF	0.1352
Annualized Capital Costs ($/yr)	ACC	$ 146,497
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 294,000
Other Indirect Annual Costs ($/yr)	OAC	$ 43,327
Total Annualized Costs ($/yr)	TAC	$ 483,824
NOx Control Efficiency (%)	Eff	21%
Baseline Actual NOx Emissions (ton/yr)	BAE	131.6
Future Utilization Adjustment (%)	FUA	0%

Projected Actual Emissions (ton/yr)	PAE	131.6
Estimated Reductions (ton/yr)	ER	27.4
1999$ Cost Effectiveness ($/ton)	**CE1**	**$ 17,688**
Consumer Price Index Ratio	CPI	$ 1.83
2023$ Cost Effectiveness ($/ton)	**CE2**	**$ 32,383**

(A) Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, Nov 1999, Table A-4, 25
Note: Unit T-D01 is ~ 24 MW (mechanical) and thus reasonably similiar in size to the 25 MW Class

d)

estimates (based on primary data source)

Source
(A)
(A)
(A)
-
Not specified by Enterprise
(A)
Enterprise August 2023 FFA update
Enterprise initial (2019) FFA and August 2023 update
-
-
(A)
EPA Cost Manual, Section 2.6.5.8
-
-
CY 2018 emissions testing and average operating hours (2016-2
Not specified by Enterprise

-
-
-
https://www.bls.gov/data/inflation_calculator.htm
-

MW Class
used in the analysis.

Methodology/Note
Total system cost
Taxes Freight and installation direct costs
Indirect installation and contingency
PEC + ODC + IDC
TCC + AC
Standard CRF calculation
TCI x CRF
Annual costs (does not include Capital Recovery)
4% of TCI
ACC + OMC + OAC
(Current actual - Post Control)/Current actual
021)

BAE x (1 + FUA)
PAE x Eff
TAC/ER

Based on CPI for All Urban Consumers: Refer to table in CPI Worksheet

CE1x CPI

Facility Information

Enterprise - Blanco C & D	**Facility**
Pre 1978 GE M5322B NG CT, 32,550 HP	**Units**
T-D01	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
9.0	**Post-control Emissions Rate (ppmv**

Supporting Information

2020	Calendar year associated with cost e
32,550	Nameplate Capacity (hp/unit)

Economic Evaluation

Cost Component		**T-D01**
Purchased equipment costs ($)	PEC	$ -
Other Direct Capital Costs 1 ($)	ODC1	$ -
Other Direct Capital Costs 2 ($)	ODC2	$ -
Indirect Capital Costs ($)	IDC	$ -
Total Capital Costs - Direct ($)	TCC	$ -
Additional Capital ($)	AC	$ -
Total Capital Investment ($)	TCI	$ 78,705,900
Interest Rate (%)	R	10.50%
Useful Life (yr)	Y	30
Capital Recovery Factor	CRF	0.1105
Annualized Capital Costs ($/yr)	ACC	$ 8,699,244
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 46,465
Other Indirect Annual Costs ($/yr)	OAC	$ -
Total Annualized Costs ($/yr)	TAC	$ 8,745,709
NOx Control Efficiency (%)	Eff	83%
Baseline Actual NOx Emissions (ton/yr)	BAE	131.6

Future Utilization Adjustment (%)	FUA	0%
Projected Actual Emissions (ton/yr)	PAE	131.6
Estimated Reductions (ton/yr)	ER	109.3
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 80,025**
Consumer Price Index Ratio	CPI	$ 1.18
2023$ Cost Effectiveness ($/ton)	**CE2**	**$ 94,430**

d)

estimates (year not specified in submission)

Source
Included in TCI
Included in TCI
Included in TCI
Included in TCI
Included in TCI
Included in TCI
9/8/20 info from El Paso Natural Gas
Enterprise August 2023 FFA update
ERG experience based on discussions with CT manufacturers
-
-
Enterprise August 2023 FFA update (2023$ converted to 2020$
-
-
-
CY 2018 emissions testing and average operating hours (2016-2

Not specified by Enterprise
-
-
Cost info provided by EPNG on 9/8/20 so assumed costs are in
https://www.bls.gov/data/inflation_calculator.htm
-

Methodology/Note
All-in estimate ($/HP) x Maximum Power Output (HP)
Standard CRF calculation
TCI x CRF
Incremental overhaul costs for DLN retrofit
4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs a
ACC + OMC + OAC
(Current actual - Post Control)/Current actual
021)

BAE x (1 + FUA)
PAE x Eff
TAC/ER

Based on CPI for All Urban Consumers (July 2020 -> July 2023)

CE1 x CPI

ssociated with replacement with an equivalent/like-kind unit

Facility Information

Enterprise - Blanco C & D	**Facility**
Pre 1978 GE M5322B NG CT, 32,550 HP	**Units**
T-D01	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (lb/hr)**

Additional Information

2023	Calendar year associated with cost e
32,550	Nameplate Capacity (hp/unit)

Economic Evaluation

Cost Component		**T-D01**
Purchased equipment costs ($)	PEC	$ -
Other Direct Capital Costs 1 ($)	ODC1	$ -
Other Direct Capital Costs 2 ($)	ODC2	$ -
Indirect Capital Costs ($)	IDC	$ -
Total Capital Costs - Direct ($)	TCC	$ 67,834,200
Additional Capital ($)	AC	$ -
Total Capital Investment ($)	TCI	$ 67,834,200
Interest Rate (%)	R	10.50%
Useful Life (yr)	Y	25
Capital Recovery Factor	CRF	0.114
Annualized Capital Costs ($/yr)	ACC	$ 7,762,221
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 6,552,797
Additional Electricity Demand ($/yr)	AED	$ 13,105,594
Associated non-electricity O&M ($/yr)	AOM	$ -
Annual Fuel Credit ($/yr)	AFC	$ (6,552,797)
Other Indirect Annual Costs ($/yr)	OAC	$ -
Total Annualized Costs ($/yr)	TAC	$ 14,315,018
NOx Control Efficiency (%)	Eff	100%

Baseline Actual NOx Emissions (ton/yr)	BAE	131.6
Future Utilization Adjustment (%)	FUA	0%
Projected Actual Emissions (ton/yr)	PAE	131.6
Estimated Reductions (ton/yr)	ER	131.6
2023$ Cost Effectiveness ($/ton)	**CE**	**$ 108,750**

estimates

Source
Included in TCC
Included in TCC
Included in TCC
Included in TCC
-
-
-
Enterprise Aug 2023 CBI update
Consistent with other FFAs
-
-
ERG calculation
Engineering judgement
ERG calculation
-
-
-

CY 2018 emissions testing and average operating hours (2016-2
Not specified by Enterprise
-
-
-

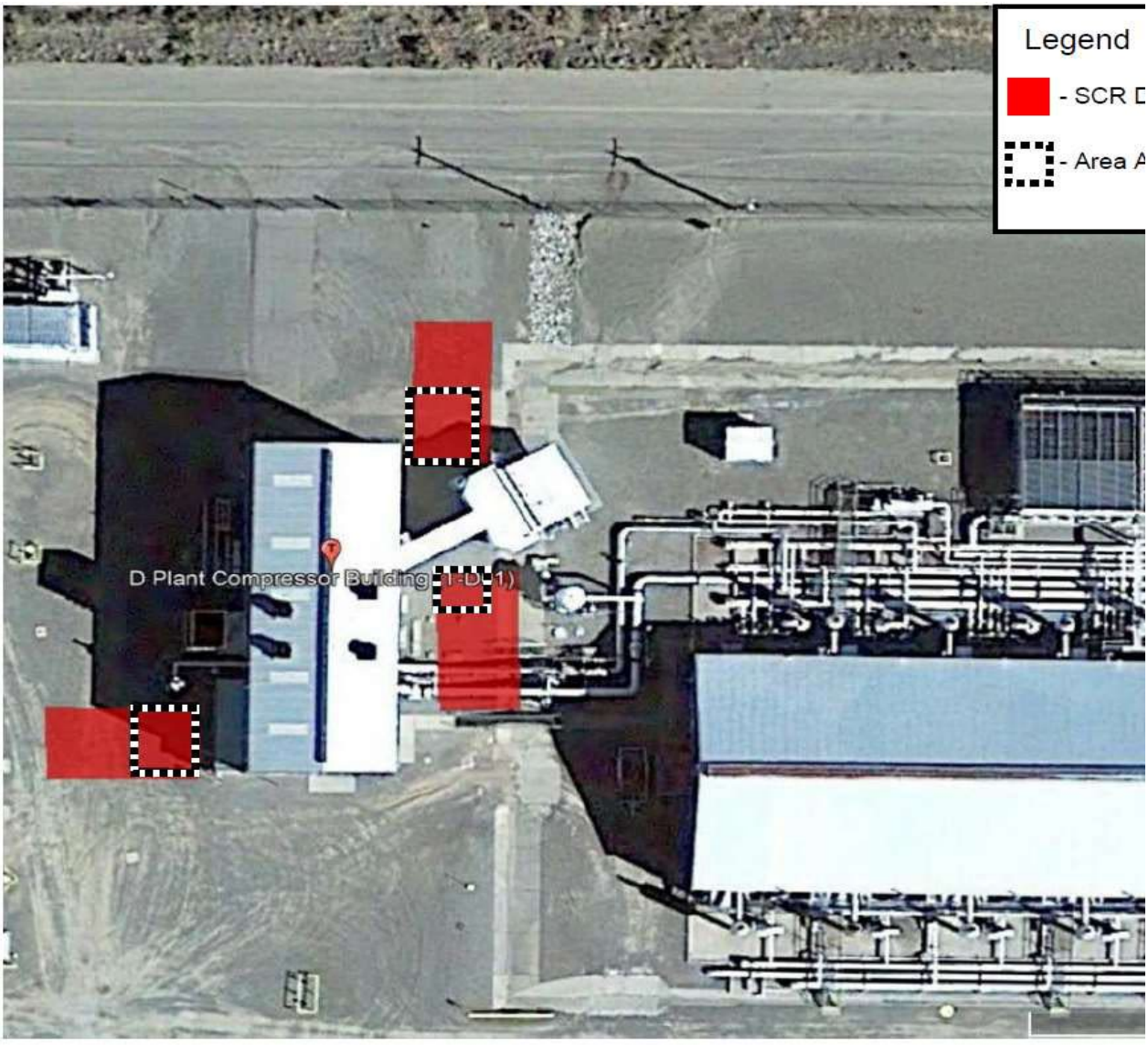
Methodology/Note
Enterprise provided a cost estimate for electrification using EPA Cost Control Manual Section 5.2, which pertains to acid gas scrubbers. As this is not applicable to replacement with EMD, a Total Capital Cost metric of $2,084 (2023$/hp) was calculated using detailed cost information provided by other facilities. The TCI figure assumes no costs associated with substation or distribution line upgrades. This assumption underestimates costs given that Enterprise indicated in its August 2023 update that utility infrastructure upgrades would be needed to support electrification at all three of its facilities.
TCC + AC
Standard CRF calculation
TCI x CRF
AED + AOM + AFC
Assumes unit at 60% load, 95% efficiency and a $0.10/kWh price
Assumed to be negligible
Assumed equal to 50% of AED
4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary cc
ACC + OMC + OAC
No emissions from EMD units

021)
BAE x (1 + FUA)
PAE x Eff
TAC/ER

osts associated with replacement with an equivalent/like-kind unit

Enterprise indicated in its initial 2019 FFA submittal, 2020 follow-up and 2023 update that there is insuff
accommodate SCR. In support of its assertion, it indicated (2020 follow up) that CECO-Peerless stated th
approximately 40' x 20' is required for an SCR unit" and a copy of the correspondance was provided. An
facility was provided in the 2020 follow up which suggests that new buildings (or substantial extensions
building) would be required to house an SCR. The associated costs of building construction coupled with
exhaust system modifications would be costly. Considering the calculated cost effectiveness of SCR for
Mexico, it is reasonable to conclude that SCR is cost prohibitive for the Blanco C/D units.

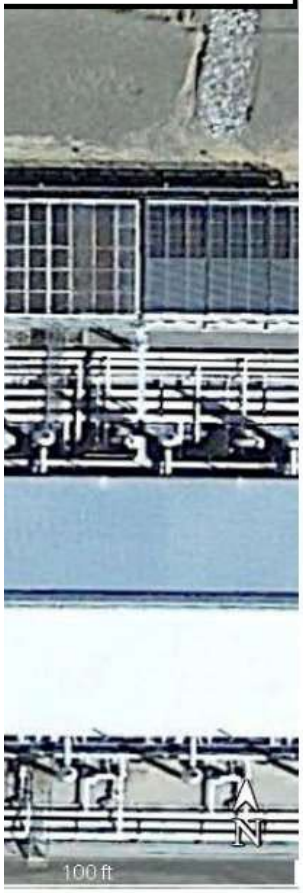
Image from 2/14/20 update
Aerial View of Blanco C/D



ïcient space to
ıat "an area of
aerial map of the
of the existing
ı corresponding
ɔther CTs in New

Dimensions

Available for SCR



Facility	Enterprise - Blanco C&D		
Unit	T-C01	T-C02	T-D01
2016 Hrs	8591	8505	8003
2017 Hrs	8603	8644	8617
2018 Hrs	8635	8692	8651
2019 Hrs	8357	8760	8558
2020 Hrs	8444	8634	8652
2021 Hrs	8663	8663	8628
2022 Hrs	8458	8442	8442
Rep Avg Period	2016-21	2016-21	2016-21
Average Hours	8549	8650	8518

Representa

Emissions Data (from Enterprise)			
Unit	T-C01	T-C02	T-D01
Date	2022	2022	2022
NOx (ppm)	41.5	53.4	50.2

Emissions Test Data (from Reports)			
Unit	T-C01	T-C02	T-D01
Test Date	10/3/2018	10/2/2018	10/1/2018
Load during test (%)	98%	96%	96%
Power Output (hp)	21,834.4	21,388.8	21388.8
NOx (ppm)	45.94	63.24	53.02
NOx (lb/hr)	32.04	43.3	29.67
NOx (g/hp-hr)	NP	NP	NP
NOx (lb/MMBtu)	NP	NP	NP

NP - Not Provided

Additional Info			
Unit	T-C01	T-C02	T-D01
Nameplate Power (hp)	22,280	22,280	32,550

Calculations			
Unit	T-C01	T-C02	T-D01
NOx (lb/hr, @100% load)	32.7	45.1	30.9
NOx (g/hp-hr)	0.67	0.92	0.43

ıtive averaging period per NMED analysis; 2022 data excluded because it was still preliminary at time of a

analysis

CPI

Year	CPI
1999	0.65
2000	0.67
2018	0.98
2019	1
2020	1.02
2021	1.04
2022	1.12
2023	1.19

Enterprise indicated in its initial 2019 FFA submittal, 2020 follow-up and 2023 update that there is insuff
accommodate SCR. In support of its assertion, it indicated (2020 follow up) that CECO-Peerless stated th
approximately 40' x 20' is required for an SCR unit" and a copy of the correspondance was provided. An
facility was provided in the 2020 follow up which suggests that new buildings (or substantial extensions
building) would be required to house an SCR. The associated costs of building construction coupled with
exhaust system modifications would be costly. Considering the calculated cost effectiveness of SCR for
Mexico, it is reasonable to conclude that SCR is cost prohibitive for the Chaco units.

Image from 2/14/20 update
Aerial View of Chaco



ïcient space to
ıat "an area of
aerial map of the
of the existing
ı corresponding
ɔther CTs in New



Attachment C

Solar Turbines
A Caterpillar Company

Solar Turbines Incorporated

9330 Sky Park Court
San Diego, CA 92123
Tel: (858) 694-1616

Submitted Electronically

September 9, 2024

Subject: **Solar Compressor Sets - NOx Reductions per NM Regional Haze Rule Requirements**

There are very few gas turbine compressor sets in the world equipped with SCR systems. While a 90% NOx reduction rate is generally applicable to base-loaded generator sets producing electrical energy usually in combined cycle or cogeneration configurations, the same NOx reduction cannot be assumed for compressor sets which operate in simple cycle mode and experience variable loads swings as part of normal operations.

For reference, there are two compressor stations in Virginia with Solar Turbines equipped with SCR systems. NOx limits for these stations are based on approximately a 60% reduction from the SCR systems. 60-80% NOx reduction is a more realistic range of NOx reduction achievable with SCRs placed on gas turbine compressor sets.

The Solar Centaur 40 and Mars 100 gas turbines at South Carlsbad Station and the Chaco Gas Plant, respectively are of the vintage diffusion flame version of gas turbines which have higher NOx emissions than modern dry-low emissions (DLE) gas turbines sold today. Solar offers upgrades for these turbines to DLE versions (termed 'SoLoNOx' – Solar's DLE system) which will reduce NOx emissions greater than SCR systems with the added benefit of avoiding NH3 emissions which are produced by the SCR process. The SoLoNOx upgrades will also be less costly and require much less unit downtime than SCR installation.

Specifically, Solar offers SoLoNOx upgrades on these units to levels of 15 ppm NOx for the Centaur 40 and to 9 ppm NOx for the Mars 100. The SoLoNOx levels represent NOx reductions of greater than 90% from the existing diffusion flame configurations.

In summary, upgrading the existing Solar turbines at South Carlsbad Station and the Chaco Gas Plant to modern SoLoNOx combustion systems is a more cost-effective and environmentally beneficial solution than retrofitting to SCR.

Please call me at 858.505.8554 if you have any questions.

Sincerely,

Anthony Pocengal
Solar Turbines Incorporated

cc: Joey Guillen, Solar Turbines Incorporated

Caterpillar: Confidential Green

R. Thomas Mitchell

To whom it may concern:

Please see the comment letter provided here, with supporting attachments included in the same document.

Thank you

El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

Submitted Via Email and the Regional Haze Public Comment Portal

20 September 2024

Air Quality Bureau
New Mexico Environment Department
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505
nm.regionalhaze@env.nm.gov

RE: El Paso Natural Gas Company, L.L.C.'s Response to the New Mexico Environment Department's August 26, 2024 Draft of the State of New Mexico Regional Haze State Implementation Plan Revision for the Second Planning Period (2019-2028)

To whom it may concern:

El Paso Natural Gas Company, L.L.C. ("EPNG") provides comment on the August 26, 2024 Draft of the Regional Haze State Implementation Plan ("SIP") Revision for the Second Planning Period (2019-2028) ("Draft SIP Revision") prepared by the New Mexico Environment Department ("NMED"), Air Quality Bureau ("AQB"), in partnership with the City of Albuquerque Environmental Health Department ("EHD").[1] The Draft SIP Revision identifies three EPNG facilities for consideration in imposing emissions rate limits or in certain cases, even full replacement of equipment, under the Regional Haze Program pursuant to the federal Clean Air Act ("CAA" or "the Act"): the Blanco Compressor Station A ("Blanco A"), Pecos River Compressor Station ("Pecos River"), and Washington Ranch Storage Facility ("Washington Ranch"). NMED states that it plans to request a hearing with the New Mexico Environmental Improvement Board ("EIB") based on the Draft SIP Revision in September 2024,[2] after incorporating public feedback received through this comment solicitation period.

NMED's proposed timeline for requesting a rulemaking with EIB, however, reveals that NMED will not have nearly enough time to digest and incorporate comments on a highly technical area of law, policy, and engineering. NMED took seven months from receiving the January 2024 comments on its proposed four-factor analyses, and then only left the public 25 days to comment on the Draft SIP Revision. Further, the New Mexico process for the second regional haze planning period has been ongoing since 2019. In this context, the mere 25-day timeline for EPNG and other subject parties to respond is unjust and deprives potentially regulated parties of their

[1] EHD is responsible for CAA compliance within its jurisdiction in Albuquerque. For the sake of simplicity, this comment letter refers to NMED as the author of the Draft SIP Revision.

[2] *See* NMED, Regional Haze Planning (last visited Sept. 10, 2024), https://www.env.nm.gov/air-quality/reg-haze ("NMED anticipates petitioning the Environmental Improvement Board to adopt the proposed plan and rule on or about September 11, 2024. NMED further anticipates requesting that the Board hold a mid-December hearing on the proposed plan and rule at the Board's September 27, 2024 regular monthly meeting.").



due process and CAA rights to be heard on the matter. NMED's significant delay in this process past the July 31, 2021, SIP submittal deadline should not be a justification for imposing unduly constrained timelines on public commenters including impacted sources, and which will also not allow the agency to meaningfully absorb, let alone respond and react to, comments on the Draft SIP. Stated otherwise, NMED and EPA cannot adopt deadlines that deprive stakeholders including EPNG of their due process including rights under the Administrative Procedure Act, the CAA, the New Mexico Administrative Procedures Act, and New Mexico Air Quality Control Act.[3]

EPNG understands that the New Mexico Oil and Gas Association ("NMOGA") has or will file a request for a reasonable extension of time to respond to NMED's Draft SIP. EPNG supports the NMOGA extension request.

I. Executive Summary

In this letter, we provide general background on the Regional Haze Program, comments on the Draft SIP Revision's methods and assumptions, along with source-specific comments related to EPNG's facilities identified for new emissions-rate limits by the Draft SIP Revision. In summary, we make the following conclusions and requests to NMED:

1. The Regional Haze Rule does not require a state to evaluate all emissions sources within each implementation period. NMED unreasonably ignored this important point, and instead of surgically identifying the most impactful sources, NMED's screening methodology uses an overinclusive and very rough metric for determining which sources to evaluate for further analysis. This was particularly unnecessary given the strong progress already made on reducing visibility impairment in Class I areas within New Mexico and out of state, especially through the retirement of large electric generating stations like the San Juan Generating Station. The bottom line is that NMED's approach for EPNG's facilities will result in costly retrofits that will have only a minimal (at most) impact on visibility conditions in Class I areas.

2. EPNG addresses three threshold legal issues. The first two caused NMED to erroneously propose controls for EPNG's units. EPNG discusses the last issue to support the Draft SIP Revision's current approach, and because NMED had earlier suggested it might have authority to impose operating restrictions on sources.

    a. The CAA, which NMED is acting under, does not authorize *replacement* of emissions *sources*, whether that includes replacement of a natural-gas fired unit with an electric unit or with another natural-gas fired unit.

    b. U.S. Environmental Protection Agency ("EPA") guidance provides that *actual* emissions should be used for cost-effectiveness analysis, not potential to emit.

[3] 42 U.S.C. § 7410(a)(2); 40 C.F.R. § 51.102; 5 U.S.C. § 553; NMSA 1978, §§ 12-8-3, 74-1-9.



c. NMED may not impose operating hour restrictions on engines and turbines regulated by the U.S. Federal Energy Regulatory Commission ("FERC") that are used to pump natural gas in interstate transport. While NMED is not proposing to do so, EPNG makes this point clear, should NMED consider changing approach.

3. On top of the legal errors identified in Item No. 2.a & 2.b., above, NMED's four-factor analyses for Blanco A and Pecos River make multiple technical errors that lead to significant understatement of the cost-per-ton of reductions from emissions units at these facilities. Without these understatements, none of the units at Blanco A or Pecos River would be subject to Regional Haze Program emissions-rate limits.

4. Regarding Washington Ranch, EPNG does not agree with the assessment of replacement or electrification, per Item No. 2.a., above. Setting that issue aside, EPNG does agree with the overall conclusion that there are no cost-effective incremental reduction options from Washington Ranch, even if replacement or electrification were allowed. EPNG does not oppose an emission limit of 3.0 g/hp-hr based on the existing LEC on the two units at Washington Ranch.

5. Finally, the overall consideration of air-quality improvements shows why imposing limits on the units selected for additional emissions limits at Blanco A and at Pecos River is unnecessary and unreasonable, consistent with EPA guidance.

II. Legal and Factual Background

A. Brief Regional Haze Program Background

EPNG does not provide an exhaustive background on the Regional Haze Program but instead provides a brief overview as a framing for this comment letter.

Through the CAA, Congress declared "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution."[4] Class I areas are national parks and certain protected wilderness areas. To attain that goal, Congress directed that EPA promulgate regulations that require, for states with Class I areas (or with emissions that may reasonably be anticipated to cause or contribute to any impairment of visibility in any out-of-state Class I area) "to contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward the national goal [of no human-caused visibility impairment]."[5]

[4] 42 U.S.C. § 7491(a)(1).

[5] *Id.* § 7491(b)(2).



Relevant here, for determining reasonable progress, states must consider "**[1]** the cost of compliance, **[2]** the time necessary for compliance, and **[3]** the energy and nonair quality environmental impacts of compliance, and **[4]** the remaining useful life of any existing source subject to such requirements."[6] The four enumerated items here are those factors that states and EPA consider as part of a "four-factor analysis." The Act also specifies that each SIP should contain a long-term strategy for making reasonable progress toward meeting the national goal.[7]

EPA has promulgated several iterations of regulations, known as the "Regional Haze Rule" or "RHR," under this statutory authority, which includes the most recent update in 2017.[8] Through the RHR, EPA set the goal date for achieving natural visibility conditions of 2064.[9] The RHR, consistent with the Act, uses distinct planning periods in which states aim to reduce their emissions at a rate of progress that will achieve the national goal by 2064. Currently, states are in the second implementation period of this process, and the key provision from the RHR applicable here is therefore 40 C.F.R. § 51.308(f), which provides the requirements for periodic SIP review.

After the amended RHR was promulgated in 2017, EPA then issued guidance to states in 2019 that walks through a step-by-step process for states to follow in developing their SIPs for the second regional haze planning period. The guidance is entitled, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," dated August 20, 2019 ("2019 EPA Guidance").[10] Nearly two years later, on July 8, 2021, EPA issued additional guidance, entitled "Clarifications Regarding Regional Haze State Implementation Plans for the Second Planning Period" ("2021 Clarification").[11]

B. Relevant Background on Draft SIP Revision.

NMED's Draft SIP Revision is proposed for promulgation to satisfy the RHR's requirements for the second planning period. The second planning period covers the years 2019 to 2028, and SIP revisions for this period were due on July 31, 2021,[12] but the New Mexico process has been delayed and has not met the deadline. The Draft SIP Revision takes a multi-step approach that, in broad strokes: (1) identifies Class I areas in New Mexico and nearby out-of-state Class I areas; (2) explains and applies a screening methodology for determining which sources of emissions would be subjected to a four-factor analysis; (3) summarizes the four-factor analyses performed

[6] *Id.* § 7491(g)(1).

[7] *Id.* § 7491(b)(2)(B).

[8] *See* 82 Fed. Reg. 3,078 (Jan. 10, 2017) (regulations codified at 40 C.F.R. Parts 51 and 52).

[9] 40 C.F.R. § 51.308(f)(1)(vi)(A).

[10] Available at: https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

[11] Available at: https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf.

[12] Draft SIP Revision at 7.

for certain emissions units at each selected source; (4) summarizes the emissions-rate limits resulting from the four-factor analysis; and (5) reviews the assessed emissions reductions against the uniform rate of progress that is needed to attain natural visibility conditions at each Class I area.[13]

Specific to EPNG, the Draft SIP Revision proposes imposing emissions limits on six units owned by EPNG, as set forth in Table 1, below. The limits are based on selective catalytic reduction ("SCR") as a control, continued use of existing low-emission combustion ("LEC") as a control, and replacement of gas-fired units with new gas-fired units (which is beyond NMED's authority, as described in Section III.A).

Table 1. – Draft SIP Revision Proposed Emissions-Rate Limits on EPNG Units

Facility	Unit	Proposed NOx Emissions-Rate Limit	Basis for Limit	EPNG Position
Blanco A	A11	0.5 g/hp-hr	Replacement	Oppose
Blanco A	A13	0.5 g/hp-hr	Replacement	Oppose
Pecos River	A-02	3.64 lb/hr	SCR	Oppose
Pecos River	A-03	4.05 lb/hr	SCR	Oppose
Washington Ranch	1	3.0 g/hp-hr	Existing LEC	Does not oppose
Washington Ranch	2	3.0 g/hp-hr	Existing LEC	Does not oppose

For the Blanco A and Pecos River units, NMED established the emissions-rate limits based on capital-intensive projects at each. For Blanco A, NMED would have EPNG replace the existing units with new natural gas-fired engines. The emissions-rate limit for Pecos River is based on installation of SCR. NMED should not move forward with these proposed emissions-rate limits because (1) these sources should not have been screened in for four-factor analysis, (2) NMED does not have the legal authority to require replacement of the Blanco A units, (3) NMED's four-factor analysis used technically flawed assumptions, and (4) an overall evaluation of visibility impacts demonstrates that New Mexico can make reasonable progress to achieving the 2064 visibility goal without requiring reductions from Blanco A or Pecos River.

III. Threshold Legal Issues.

Before turning to the more technical issues in the Draft SIP Revision, EPNG highlights three significant threshold legal issues. The first is that NMED does not have authority to require replacement or electrification of a source.[14] In the context of natural-gas fired engines and

[13] *See* Draft SIP Revision, at 10.

[14] NMED's Draft SIP Revision categorically excludes electrification as a potential requirement on the basis that "there are simply too many unknowns to reliably estimate the costs involved" and feasibility. Draft SIP



turbines, this means NMED is incorrect in its assertion that it can require replacing an engine or turbine with a new natural-gas fired unit or that NMED can require either type to be converted to an entirely different technology—i.e., an electric motor, powered by the grid.

Second, NMED erroneously concluded that the proper emissions baseline to use in the four-factor analysis is the *potential* to emit rather than *actual* emissions. This position is a blatant attempt to reduce the cost/ton of the chosen technology and is directly contrary to authoritative EPA guidance on the matter, and would (if adopted) result in erroneously subjecting EPNG's engines to the Regional Haze SIP.

Third, EPNG notes that NMED may not impose operating hour restrictions on FERC regulated natural gas pipelines shipping natural gas in interstate commerce outside of the authority under the CAA.

A. The CAA and RHR Do Not Authorize Replacement or Electrification.

EPNG respectfully disagrees with NMED's consideration of replacement or electrification as an option for NOx emissions reductions.[15] Neither replacement nor electrification is authorized by the Regional Haze provision in the CAA or the implementing regulations, and units cannot be forced to undertake such a fundamental change to their facilities. The Regional Haze Rule is the authority under which NMED proposes that any final rules will be imposed by the EIB, and so any state law authority is not relevant.

A fundamental principle of the Clean Air Act is that Congress did not intend to eliminate emissions sources; rather, Congress simply intended for *control* of emissions sources—*e.g.*, through scrubbers, capture devices, or other methods that reduce emissions of a pollutant without affecting the fundamental engineering design of the source.[16] Congress took this approach in part to ensure that achieving clean air goals did not unnecessarily disrupt economic activity.[17]

The Clean Air Act's regional haze provision is no different. For example, in the preamble to the 2017 Regional Haze Rule Amendment, EPA explained that "states must evaluate the *control* measures that are necessary to make reasonable progress using the four factors and develop

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Revision, at 105. However, in the Draft SIP, NMED does not disclaim authority to require electrification. As discussed herein, NMED does not have the authority to require electrification of any existing unit.

[15] As noted above, NMED categorically excluded electrification from consideration because of costs and feasibility, not because of its lack of legal authority.

[16] *See, e.g.*, *West Virginia v. EPA*, 597 U.S. 697, 728 n.3 (2022) (EPA may not "direct existing sources to effectively cease to exist" under 42 U.S.C. § 7411(d)); *Helping Hand Tools v. EPA*, 848 F.3d 1185, 1194 (9th Cir. 2016) (in determining "best available control technology" EPA may not "redefine the source" in a way that would disrupt the basic business purpose of the facility, which business purpose includes availability and use of on-site fuel).

[17] *See Sierra Club v. Costle*, 657 F.2d 298, 331 (D.C. Cir. 1981) (noting legislative history of Clean Air Act showed Congress did not want to impede long term growth or inhibit technological innovation).



their long-term strategies before they can predict future emissions reductions and conduct the regional-scale modeling used to establish [reasonable progress goals]."[18] Thus, EPA only contemplates that "controls" should be used to meet reasonable progress goals. Controls are defined in other areas of the Clean Air Act as "application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant."[19] This is further confirmed by the text of the relevant regulatory provision in the Regional Haze Rule, which refers to "installation" of a "control":

> In considering [one of the four statutory reasonable progress factors], if the State concludes that a *control measure cannot reasonably be installed* and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress.[20]

The discussion of *installing* a *control* suggests reference to an *existing* emissions unit that will remain in place and be modified, not the wholesale replacement of the emissions unit. The basic logic is simple: a control has to be installed on *something*. If an emissions unit is removed, then there is nothing on which to install the control.

The 2019 EPA Guidance interpreting the 2017 Regional Haze Rule confirms and drives home EPA's intention that "control" will be used to achieve reasonable progress, and that replacement of existing sources with other technology is not included. EPA provided the following list of "control measures that states may consider":

1. Emission reductions through improved work practices.

2. Retrofits for sources with no existing controls.

3. Upgrades or replacements for existing, less effective controls.

4. Year-round operation of existing controls.

5. Fuel mix with inherently lower SO2, NOx, and/or PM emissions. States may also determine that it is unreasonable to consider some fuel-use changes because they would be too fundamental to the operation and design of a source.

[18] 82 Fed. Reg. 3,078, 3,090-91 (Jan. 10, 2017) (emphasis added).

[19] 42 U.S.C. § 7479(3).

[20] 40 C.F.R. § 51.308(f)(2)(i) (emphasis added). Moreover, the statutory term for the requirements on certain sources to require "retrofit technology" as part of best available technology also suggests a similar approach for other sources regulated under the RHR.



6. Operating restrictions on hours, fuel input, or product output to reduce emissions.

7. Energy efficiency and renewable energy measures that could be applied elsewhere in a state to reduce emissions from EGUs.

8. Basic smoke management practices and smoke management programs for agricultural or wildland prescribed fires.[21]

Self-evidently, none of these includes replacement or electrification. The only time "replacement" appears in this list is in reference to replacement of *controls*. Further, the use of "retrofit" for sources should not be interpreted as replacement or electrification. The best available *retrofit* technology in the Regional Haze Program has never been interpreted that way; rather, the plain text of "retrofit" means the *addition to* an existing emissions unit.[22] While this list is not exhaustive, it is certainly indicative of the types of controls EPA contemplated requiring, none of which compare to electrification or replacement.

The 2021 Clarification also confirms this understanding. In that guidance, EPA clarifies that greater *efficiency of controls* could also be considered, and that guidance notably does not suggest replacement or electrification is appropriate.[23] The 2021 Clarification's discussion of the remaining useful life of a source in the four-factor analysis also discusses how the control technology—not the actual emissions source (e.g., engine)—should be the piece of equipment considered in this evaluation.[24] This discussion again contemplates that there is a *control* technology, confirming the CAA's approach of only requiring control technology and not outright replacement.

Additionally, neither EPA nor NMED may now claim that the Act's principal provision on regional haze, 42 U.S.C. § 7491, is ambiguous and then leverage that ambiguity to broaden their regulatory authority beyond the words of the statute to impose replacement or electrification requirements. That approach is now forbidden under *Loper Bright Enterprises v. Raimondo*, under which courts (and only courts) are to determine whether a statute grants an agency

[21] 2019 EPA Guidance, at 29-30.

[22] *See* "retrofit" *Merriam Webster*.

[23] 2021 Clarification, at 7 (discussing efficiency improvements of an "existing control" as a control measure to consider but not suggesting that replacement of the entire emissions unit is appropriate).

[24] 2019 EPA Guidance, at 33 ("[A]nnualized compliance costs are typically based on the useful life of the control equipment rather than the life of the source, unless the source is under an enforceable requirement to cease operation.").



authority.[25] For the reasons discussed above, the plain meaning of the statute only leaves agencies authority to require *control*s.[26]

The Draft SIP Revision only offers a terse response in support of NMED's claimed authority to require replacement or electrification, citing a supposed "prodigious flexibility afforded to states by the Regional Haze Rule."[27] But that is not even the right question; states have flexibility *within* their authority but may not act *beyond* that authority. As the authorities above demonstrate, 42 U.S.C. § 7491 does not authorize replacement or change of sources, and so New Mexico may not require that drastic step for sources.

B. Emissions Levels Used in the Four-Factor Cost-Effectiveness Analysis Should Use Actual Emissions, not Potential Emissions.

NMED is directed to use actual emissions when calculating cost-effectiveness of controls, consistent with the 2019 EPA Guidance. In that guidance, EPA provided as follows concerning visibility modeling:

> Generally, we recommend that a reasonably projected actual level of source operation in 2028 be used to estimate 2028 *actual* emissions for purposes of selecting sources for control measure analysis. Source operation during a historical period can inform this projection, but temporary factors that suppressed or bolstered the level of operation in the historical period should be considered, along with factors that indicate a likely increase or decrease in operation.[28]

Then, in discussing "emissions information to estimate the emission reductions from the potential control measures," EPA cross-referenced the above language, stating: "EPA's recommendations in this area are similar to the recommendations in Section II.B.3.b of this document regarding how emissions information is selected . . . ."[29]

This is also consistent with the approach for Best Available Retrofit Technology ("BART"). BART is relevant because it provides the other statutory guidance found in the Act's section on regional haze for evaluating the types of controls to install on sources, and statutes must be read as a

[25] 144 S. Ct. 2244, 2273 (2024) ("Courts must exercise their independent judgment in deciding whether an agency has acted within its statutory authority.").

[26] And even if the plain language could be interpreted to allow replacement, that interpretation would run afoul of the Major Questions Doctrine. As the Supreme Court has noted, Congress does not hide elephants in mouseholes by "alter[ing] the fundamental details of a regulatory scheme in vague terms and ancillary provisions." *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 468 (2001). Thus, the authority to require replacement of existing sources requires "clear congressional authorization." *Utility Air Regulatory Group v. EPA*, 573 U.S. 302, 324 (2014). *See also West Virginia*, 597 U.S. at 728 n.3 (EPA may not direct "existing sources to effectively cease to exist").

[27] Draft SIP Revision, at 102.

[28] 2019 EPA Guidance, at 17 (emphasis added).

[29] *Id.* at 30.



whole.[30] EPA provided in its BART guidelines as follows: "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon *actual emissions* from a baseline period."[31] Given the close relationship between the BART analysis and reasonable progress analysis, the direction for BART analysis should be highly persuasive here.

Last, practical reasons support using actual emissions. It is not potential emissions from a source that may affect visibility conditions; rather, it is the actual emissions.[32] Likewise, the true and more accurate measure of a cost-effectiveness analysis depends on a unit's actual emissions. Without considering actual emissions, the cost-effectiveness prong of the four-factor analysis loses all of its meaning. The point of including cost-effectiveness in the evaluation is to ensure that resources are spent wisely, where they can have the most positive impact, in recognition of the limited societal resources available to tackle environmental problems.[33]

An example illustrates the point. Consider engine *A* that runs only 10 hours a year and emits 1 ton of NOx during that operation and an otherwise identical engine, engine *B*, that runs 8760 hours while emitting 100 tons of NOx. Using potential emissions would mean that engine *A* would be assessed to have emissions of 876 tons per year, and would therefore appear far more cost-effective than engine *B*. In reality, however, engine *A* would actually be far more expensive to control based on its actual expected emissions. NMED's four factor analysis should avoid such perverse outcomes.

C. State Authority Over Interstate Natural Gas Pipelines

FERC approves or "certificates" pipelines to deliver natural gas. EPNG's pipeline system, as certificated by FERC, allows EPNG to move gas 24 hours a day, 365 days a year at its designed capacity. Given the extensive federal regulation of natural gas pipelines under FERC, states are

[30] *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 133 (2000) ("It is a fundamental canon of statutory construction that the words of a statute must be read in their context and with a view to their place in the overall statutory scheme." (quotation and citation omitted)).

[31] 40 C.F.R. Part 50, Appendix Y (Step 4.d.1.) (emphasis added).

[32] NMED recognized this fact when, in a separate context, NMED denied EPNG's request for an alternative compliance plan for the New Mexico ozone precursor rule that would have retired several engines at Blanco A. EPNG had also requested that such retirements would count toward regional haze reductions, but NMED rejected EPNG's calculation of emissions reductions for being based on emissions potentials. NMED's flip-flop on this issue demonstrates it aims to inflate baseline emissions to in turn drive down estimated costs-per-ton of reductions and inappropriately expand its regulatory reach.

[33] *See White Stallion Energy Ctr., LLC v. EPA*, 748 F.3d 1222, 1261 (D.C. Cir. 2014) (Kavanaugh, J., dissenting) (noting importance cost-effectiveness analysis "in an age of limited resources available to deal with grave environmental problems, where too much wasteful expenditure devoted to one problem may well mean considerably fewer resources available to deal effectively with other (perhaps more serious) problems" (quoting *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 233 (2009)), rev'd *Michigan v. EPA*, 576 U.S. 743 (2015).



largely preempted from imposing additional regulations on such pipelines, except for specific and narrow exceptions, including the CAA.[34]

NMED should bear this in mind as it moves forward with the SIP revision. In particular, this means that New Mexico may not exercise its own state law authority to impose requirements on interstate natural gas pipelines that go beyond what the CAA authorizes.

IV. NMED's Source Selection Process Takes an Overly Aggressive Approach not Required by the Act or RHR and that Relies on Faulty Technical Assumptions.

As discussed herein, NMED's screening methodology for determining which sources to evaluate through the four-factor analysis is over-inclusive and not required by the Act or RHR. NMED's approach is also not technically supported and should be rejected as arbitrary and not based in substantial evidence on the record.[35]

A "key flexibility of the regional haze program is that a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures."[36] Accordingly, NMED does not need to subject all sources of potential visibility-impairing emissions in New Mexico to a four-factor analysis for determining reasonable progress goals.

This is because, as the 2019 EPA Guidance observes, the CAA does not require a specific list of source types for which an analysis must be performed, in marked contrast to the statutory provisions directing that certain types of sources be subject to a BART analysis.[37] This is also consistent with the RHR, which takes a phased approach and does not require that states achieve natural visibility conditions in one fell swoop.[38] Thus, "it is reasonable and permissible for a state

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[34] *See Dominion Transmission, Inc. v. Summers*, 723 F.3d 238, 240 (D.C. Cir. 2013) (Natural Gas Act establishes a comprehensive scheme of federal regulation but does not preempt state authority under the CAA).

[35] *See* NMSA 1978, § 74-2-9 (court of appeals shall set aside agency action if it is arbitrary, capricious, or an abuse of discretion or not supported by substantial evidence in the record); *Pub. Serv. Co. of N.M. v. New Mexico Envtl. Dept.*, 1976-NMCA-039, ¶ 18 ("There is no substantial evidence in the record to support the Board's final reason 'G'. . . . Whether sulfur dioxide emissions can or do combine with other elements in the atmosphere to produce a visible gas, or whatever, the record does not indicate.").

[36] 2019 EPA Guidance, at 9.

[37] *Id.*; *see also* 42 U.S.C. § 7491(b)(2)(A) ("[E]ach major stationary source which is in existence on August 7, 1977, but which has not been in operation for more than fifteen years as of such date, and which, as determined by the State (or the Administrator in the case of a plan promulgated under section 7410(c) of this title) emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area, shall procure, install, and operate, as expeditiously as practicable (and maintain thereafter) [BART] . . . .").

[38] 2019 EPA Guidance, at 9 ("Selecting a set of sources for analysis of control measures in each implementation period is also consistent with the Regional Haze Rule, which sets up an iterative planning



to distribute its own analytical work, and the compliance expenditures of source owners, over time by addressing some sources in the second implementation period and other sources in later periods."[39] Finally, "one function of the source selection step is to reduce the number of sources for which the full set of relevant factors will be characterized."[40]

The 2021 Clarification is also consistent with this view on source selection, stating: "In general, states with larger sources that contribute more to visibility impairment should select more sources, and states with relatively small sources compared to their neighbors should nonetheless select their largest in-state sources."[41] The 2021 Clarification's principal recommendation is that states should select sources that are "among the largest sources of visibility impairment in the state."[42] As discussed below, NMED's source-selection approach exceeded this direction, and NMED's over-inclusive approach appears to stem from a misinterpretation of guidance.

A. NMED's Use of the Q/d Metric Should be Reevaluated or at Least Better Supported.

In determining the sources for which a four-factor analysis would proceed, NMED used the "Q/d" metric. Q/d is a measure of the quantity (the "Q") of emissions from a source divided by the distance (the "d") of the emissions from a particular Class I area. To select the Q, NMED aggregated emissions of NOx and SO2 from each source, weighting both emission types equally.[43] To select the d, NMED used the distance to the closest (in-state or out-of-state) Class I area from the particular source.[44] This process yields source specific Q/d scores, provided in the Draft SIP Revision's Table 6-1 (beginning on page 94).

The highest Q/d score was 461, for San Juan Generating Station, and NMED set a cut-off threshold where every facility with a Q/d score of 5.6 or greater would be selected for the four-factor analysis.[45] NMED adopted 5.6 as the cut-off "necessary to capture 80% of the total NOx and SO2 emissions from all New Mexico Title V facilities combined."[46] Notably, EPNG's Blanco

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process and anticipates that a state may not need to analyze control measures for all its sources in a given SIP revision. . . .").

[39] *Id.*

[40] *Id.* at 28.

[41] 2021 Clarification, at 4.

[42] *Id.*

[43] *See* Draft SIP Revision, at 92 ("NMED and EHD chose NOx and SO2 as the targeted pollutants because monitoring data indicates that aerosol species related to emissions of these two precursor pollutants (i.e., ammonium nitrate and ammonium sulfate) are the key drivers of anthropogenic visibility impairment at Class I Areas . . . ."), at 94 tbl. 6-1 (showing final Q/d scores).

[44] *See id.* at 92.

[45] *Id.* at 93.

[46] *Id.* at 92.



A is the very last facility that was screened in by NMED's misinterpretation of the proper threshold to apply; it has a Q/d score of just 5.63 compared with NMED's selected threshold of 5.6.[47]

NMED states that it selected 80% of NOx and SO2 emissions threshold based on the Western Regional Air Partnership ("WRAP") Protocol, which in turn references EPA draft guidance.[48] However the process in both the WRAP Protocol and EPA draft guidance differs significantly from NMED's.

First, the WRAP Protocol suggests using a Q/d score cut-off nearly two times higher than what NMED selected – at a score of 10: "[T]he Subcommittee suggests that states should first screen sources at a Q/d > 10 level to determine if a reasonable number of sources are identified for further review."[49] Then, only if no sources are selected does the WRAP Protocol suggest stepping down to a lower Q/d level: "**If no sources are identified**, the Subcommittee recommends stepping down the Q/d screening level in increments of one until a reasonable number of sources are identified for further review." [50] In stark contrast, NMED stepped down to scores well below 10 even though "a Q/d threshold of 10 or more would capture 13 Title V facilities responsible for" approximately 70% of the total NOx and SO2 emissions from all New Mexico Title V facilities.[51] In other words, even though the WRAP Protocol provides that a Q/d score lower than 10 is recommended only if *no sources* are identified at that level, NMED nevertheless stepped down when 13 sources have a score of 10 or above, accounting for approximately 70% of combined statewide NOx and SO2 emissions.

And NMED's explanation that it needed to include 80% of statewide NOx and SO2 emissions is based on a facially erroneous interpretation of both the WRAP Protocol and 2016 EPA Draft Guidance. Both those sources specify that the 80% measurement is related to 80% of the *visibility impacts*, not total emissions.[52] NMED's comparison of total emissions (rather than visibility impacts) is an apples-to-oranges comparison given that actual impacts of visibility depend on many other factors beyond total emissions volumes, including "transport direction/pathway,

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[47] *Id.* at 96 tbl.6-1.

[48] *See id.* at 92 (citing WRAP Reasonable Progress Source Identification and Analysis Protocol ("WRAP Protocol") and EPA Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period (2016) ("2016 EPA Draft Guidance")).

[49] WRAP Protocol, at 6.

[50] *Id.* (emphasis added).

[51] Draft SIP Revision, at 98.

[52] *See* EPA, Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period ("2016 EPA Draft Guidance"), at 72, https://www.epa.gov/sites/default/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf (referring to "a significant portion of the anthropogenic extinction budget"); WRAP Protocol, at 6 (referring to "emissions impacting [light] extinction").

dispersion and photochemical processes, or the particular days that have the most anthropogenic impairment due to all sources . . . ."[53]

Further, if NMED felt that an 80% coverage analysis was required (contrary to the WRAP Protocol), then a more accurate and consistent approach would have been for NMED to assess how many sources must be included to cover 80% of combined Q/d scores. The 2016 EPA Draft Guidance contemplates such an approach, stating: "Mechanically, it is possible to compare the sum of the individual Q/d values for the 'above threshold sources' to the sum of the Q/d values for all in-state sources."[54] However, that document nevertheless cautions that an even more precise approach for determining visibility impacts might be appropriate.[55] NMED's 80% comparison with total NOx and SO2 emissions is therefore an even rougher method than the method EPA expressed cautioned against using.

Lastly, even if the 80% threshold were correct—contrary to the foregoing arguments—NMED did not even apply that threshold properly as a matter of arithmetic, causing NMED to erroneously pull in Blanco A. As shown in Table 6-2 of the Draft SIP Revision, excluding Blanco A would have still captured sources that emit 79.98% of statewide NOx and SO2 emissions.[56] Under any rational method for rounding, 79.98% rounds up to 80%, and NMED's failure to round here elevates form of substance, pulling in a source based on a 0.02% difference. Indeed, under New Mexico's air-quality regulations, 79.98% (in fact, 79.51% and up) rounds up to 80% in other contexts,[57] and it is arbitrary and capricious to select a different rounding mechanism in this context.

In sum, EPNG recommends that NMED follow the WRAP Protocol more closely by simply using the Q/d score of 10 as a threshold. Alternatively, using 7 as a threshold appears to be a breakpoint, as the drop from 8 to 7 pulls in several more percent of statewide NOx + SO2 emissions, going from 71.5% to 78%.[58] As relevant for EPNG, this would eliminate Blanco A from further consideration. At the very least, NMED should at least round 79.98% up to 80% so that only 23 sources are selected for further consideration and thereby eliminating Blanco A.[59]

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[53] 2019 EPA Guidance, at 13.

[54] 2016 EPA Draft Guidance, at 72 n.103.

[55] *See id.* ("[T]his [approach] may not give a good indicator of what fraction of in-state light extinction impacts are attributable to the first set of sources.").

[56] *See* Draft SIP Revision, at 98.

[57] *See* 20.2.1.116(C)(2), 20.2.71.111(A)(3), 20.2.81.104(C) NMAC.

[58] *See* Draft SIP Revision, at 98 tbl. 6-2.

[59] In addition to these flaws, the Draft SIP Revision also erroneously weights NOx emissions and SO2 emissions equally. *See id.* at 94-96 tbl.6-1 (using combined, equally weighted emissions of NOx and SO2 to calculate Q/d scores). This is despite the fact that SO2 has a much greater impact on visibility impairment in the relevant areas and in fact is "*the primary driver of light extinction* at all New Mexico Class I Areas." *Id.* at 53 (emphasis added). Blanco A, Pecos River, and Washington Ranch all emit de minimis levels of SO2. But NMED arbitrarily and capriciously failed to consider this important aspect of the problem in deciding to subject those facilities to a four-factor analysis.

B. NMED Should Actually Evaluate Whether Emissions Reductions in New Mexico Will Improve Visibility at Mesa Verde.

Blanco A was selected for four-factor analysis based on its proximity to Mesa Verde National Park ("Mesa Verde"). Because it is in Colorado, Mesa Verde is an out-of-state Class I area. The Draft SIP Revision has not even determined whether sources in New Mexico should have been subject to a four-factor analysis based on proximity to Mesa Verde. Any explanation, let alone a reasoned explanation, is lacking. The RHR mandates that NMED must perform such an evaluation.

Under the RHR, states must only address regional haze "in each mandatory Class I Federal area located outside the State *that may be affected by emissions from within the State*."[60] The 2019 EPA Guidance drives this home by providing that states have "the flexibility to use any reasonable method for *quantifying* the impacts of [their] own emissions on out-of-state Class I areas."[61]

But the Draft SIP Revision arbitrarily and capriciously makes only a barebones effort at determining whether New Mexico emissions may affect out-of-state Mesa Verde, and if so, in what quantity.[62] The Draft SIP Revision states that "it is a challenging exercise to estimate with *any* degree of certainty what the quantitative impacts of individual point sources are at Class I Areas, especially when projecting visibility into the future."[63] Despite this challenge and with little technical analysis, the Draft SIP Revision states that "reductions of visibility-impairing pollutant emissions from sources in [New Mexico] can reasonably be expected to improve visibility at Mesa Verde."[64] No rigorous analysis or modeling was undertaken to support these generic statements. Thus, NMED makes contradictory statements that (1) it cannot estimate visibility impacts "with any degree of certainty" and that (2) emissions reductions in New Mexico can be expected to improve visibility in Mesa Verde. This contradiction results in arbitrary and capricious action if there is not rational connection between the facts found and the choice made, and these statements also demonstrate a lack of adequate record support.[65]

Thus, contrary to the EPA 2019 Guidance, NMED did not quantify impacts to Mesa Verde. Without more evidence and analysis in the record, NMED cannot defensibly use proximity to Mesa Verde as a basis for subjecting Blanco A to four-factor analysis. Otherwise, NMED potentially

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[60] 40 C.F.R. § 51.308(f) (emphasis added).

[61] 2019 EPA Guidance, at 8 (emphasis added).

[62] *See Bernalillo Cnty. Health Care Grp. v. New Mexico Pub. Reg. Comm'n*, 2014-NMSC-008, ¶ 9 (Agency action is arbitrary and capricious if the agency failed to consider an important aspect of the problem or offered an explanation that runs counter to the evidence.)

[63] Draft SIP Revision, at 64 (emphasis added).

[64] *Id.*

[65] *In re Rhino Envtl. Servs*, 2005-NMSC-024, ¶ 41 (holding agency action arbitrary and capricious for lack of reasoned explanation).



subjects sources in New Mexico that are not required under the RHR and reaches a decision not based on substantial evidence.

V. Critique of NMED Four-Factor Analysis for Blanco A and Pecos River

In this section, EPNG discusses technical flaws in the four-factor analysis conducted by NMED for Blanco A and Pecos River. NMED selected a cost-effectiveness threshold of $10,000/ton of NOx reduced.[66] EPNG reserves the right to assert that $10,000/ton is arbitrarily and capriciously high as a cost threshold in the forthcoming EIB rulemaking, especially when $7,500 was used as part of the recent Ozone Precursor Rule and where New Mexico is already making considerable progress on visibility impacts in Class I areas, as described in more detail in Section VII.

Under EPNG's more accurate approach for assessing cost-effectiveness of actual emissions reductions, the costs of emissions reduction projects at the Blanco A and Pecos River units selected for emissions limits would have been well over the $10,000/ton threshold selected by NMED. Accordingly, these are material assumptions that NMED should support with a strong technical basis.

EPNG raised these issues in its January 19, 2024 letter to Ms. Kirby Olson of NMED regarding NMED's draft final evaluations for Blanco A, Pecos River, and Washington Ranch.[67] EPNG provides that letter, along with its enclosures, as Attachment 1 to this letter. While the January 19, 2024 letter includes many of the same technical arguments made below, EPNG nevertheless spells the arguments out in further detail again here because NMED's Draft SIP Revision does not address the substantive technical arguments raised nine months ago. If NMED were to review these technical arguments a second time, NMED should find them persuasive and adjust course prior to requesting a hearing with EIB.

A. Overarching Critique: Baseline Actual Emissions

NMED used a potential-to-emit approach for determining baseline emissions as part of the cost-effectiveness analysis for Blanco A and Pecos River because NMED scaled up each unit as if they always operate at 100% load. Consistent section III.C, this approach is not appropriate for Regional Haze Program purposes.

Additionally, from a technical standpoint, EPA already has adequate guidance for how an appropriate measure of emissions baseline can be determined, through the proper application of the Baseline Actual Emissions ("BAE") concept.

In the EPA's Prevention of Significant Deterioration ("PSD") program, "EPA determined that it is fair and reasonable for a source to use a 10-year look back period for calculating '[BAE]' because it allows the source to consider a full business cycle in setting a baseline emissions rate *that*

[66] *Id.* at 102.

[67] *See* Attachment 1 (January 2024 Letter), at 1-8.



represents normal operation of the source for that time period."[68] As indicated in the PSD rules, the data (needed to calculate the actual emission factors, utilization rate, etc.) must adequately describe the operation and associated pollution levels for each emission unit.[69] EPA has taken the same approach to BAE for establishing a source baseline for the purpose of imposing emissions fees under 42 U.S.C. § 7511d(b). Scaling the emission factor to 100% load, as NMED did, is not in conformity with EPA's guidance on establishing BAE because that does not represent "normal operation," especially for natural gas pipeline engines, which can have variable load because of energy demand fluctuations both seasonally and year to year.

B. Blanco A Critique

As explained in this subsection, Units A-11 and A-13 at Blanco A should not be required to undertake significant capital projects as part of any final SIP developed by NMED for the regional haze program because of the costs significantly exceeding $10,000/ton. Even if NMED had authority to require replacement with new natural-gas fired engines (which it does not), NMED's four-factor analysis is deeply flawed because of multiple erroneous assumptions that collectively result in costs below the $10,000/ton threshold that NMED has selected for this process.

Before turning to the specific critiques of the Blanco A analysis, EPNG also briefly notes that NMED denied EPNG's request for an alternative compliance plan ("ACP") under 20.2.50.113 NMAC, which would have included the voluntary retirement of several engines at Blanco A. NMED rejected that request. NMED's denial in part critiqued EPNG's proposed approach for being based on potential to emit. However, NMED's four-factor analysis for both Blanco A and Pecos River is driven by inflated baseline emissions calculations that effectively result in a potential-to-emit approach, demonstrating NMED's arbitrary picking and choosing of baseline calculations. While EPNG proposed voluntarily retiring several units at Blanco A, that overall proposal was in the context of an entire ACP, where EPNG weighed the benefits of displacing costly projects at other facilities against the cost of retirements (which a company may voluntarily consider as part of an ACP under the Ozone Precurser Rule). By no means does it represent a basis, in this different context, for concluding that mandated retirement is legally permissibly or cost-effective. For the reasons explained in Section III.A, NMED may not mandate retirement under the Regional Haze program, which is likely an even more extreme remedy than replacement/electrification.

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[68] EPA, Guidance on Establishing Emissions Baselines Under Section 185 of the Clean Air Act for Severe and Extreme Ozone Nonattainment Areas that Fail to Attain the 1-Hour Ozone NAAQS by Their Attainment, at 3 (Mar. 21, 2008) (emphasis added), https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/20080321_harnett_emissions_basline_185.pdf; *see also* 40 C.F.R. § 52.21(b)(48).

[69] *See* 40 C.F.R. § 52.21(b)(48)(ii)(e) (Average rate may not "be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions.").



1. Baseline Emissions Calculations

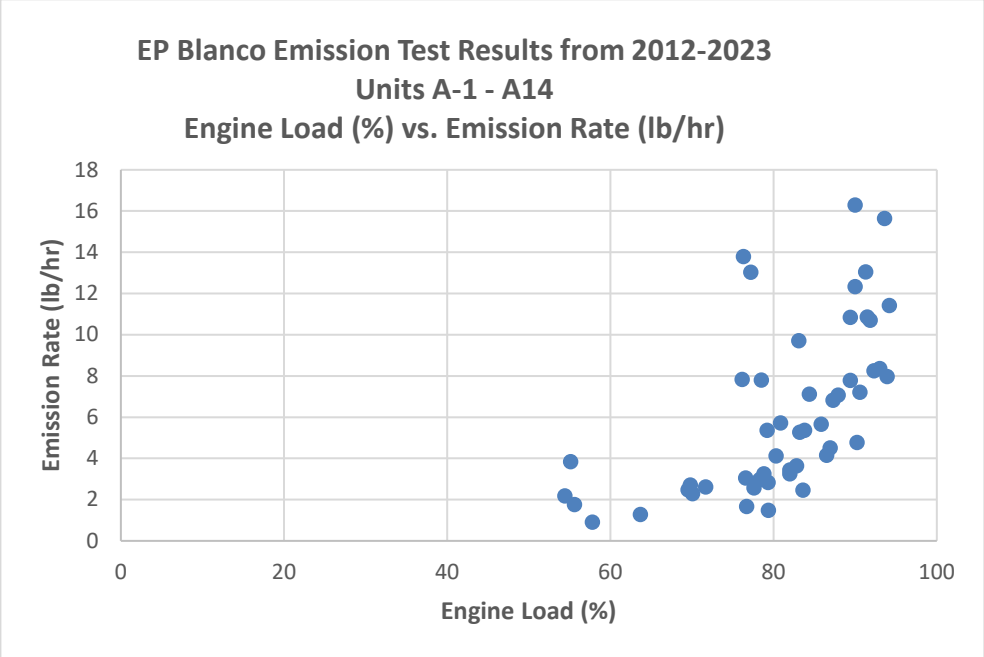
Contrary to EPNG's method, NMED relied on one emission test data (in lb/hr) from the period of 2022-2023 for each of the six units (units A-2, A-3, A-4, A-9, A-11 AND A-13) and then extrapolated it to 100% load to calculate the Baseline Actual Emissions BAE rate (in lb/hr). For the remaining eight units, NMED used the average of the six units' BAE rates to be the BAE rate for these remaining eight units (in lb/hr). This method of calculating BAE is flawed for the following reasons:

- The engines at Blanco A Compressor Station operate at variable loads. It is incorrect to calculate the BAE rate assuming the engines operate at 100% load all the time. In fact, these engines rarely operate at 100% load, if at all, as demonstrated in Table 2, below, which shows average annual operating hours far below 8760 for all units, and as low as 1 and 2 for two others. Additionally, some engines are restricted by the attached compressors, and they cannot physically operate at 100% load.

- NMED averaged six (6) emission test data points (one each from units A-2, A-3, A-4, A-9, A-11 and A-13) from the period of 2022-2023 to establish the BAE rates for all 14 units. As stated by EPA in its BAE guidance, a longer look back period is needed to allow the source to consider a full business cycle in setting a BAE rate that represents normal operation for that time period. One emission test data is not representative of normal operation of the source, and certainly not as averaged across 14 units.

- NMED relied on a linear function of the engine load percent and test data to establish the BAE rate. As demonstrated in Figure 3, the relationship between the test data and engine load percent is not a linear function. The emission rate depends on many variables; engine load percent is one of the many variables.

Figure 3. – Blanco A Emission Test Results



2. O&M Costs

In NMED's draft final control cost evaluations spreadsheet, NMED assumed that the incremental O&M cost of a LEC retrofit is expected to be negligible. EPNG submitted these costs several years ago as part of its initial submissions. Considering the passage of time and the rate of inflation during that time, EPNG obtained up-to-date estimated costs for primary parts associated with the emission controls from the vendor. EPNG updated additional O&M costs to provide in its January Letter, in Enclosure 1 therein. NMED did not update its costs to reflect the recommendations that EPNG provided in the January Letter, but EPNG urges NMED to do so now because failing to use the most updated data that is already available would result in arbitrary and capricious agency action.

3. Allowance for Funds Used During Construction ("AFUDC")

AFUDC is a generally accepted regulatory accounting method under which the cost of financing the capital construction projects incurred during construction phase is added to the cost of the asset. AFUDC offers a way for the entity to recover its pre-operational financing costs. Including AFUDC in construction projects follows the guidelines for accounting in FERC's Uniform System of Accounts. Because a FERC-regulated entity, such as EPNG, does not earn a return on assets under construction to cover financing costs incurred during the construction period, regulators typically allow entities to capitalize an allowance for funds used during construction for future recovery. EPNG requests that NMED incorporate the use of AFUDC in its cost analysis as shown in EPNG's January Letter, in Enclosure 1 therein.

4. Replacement Capital Costs

The Draft SIP Revision's conclusion on the cost-per-ton for replacement of engines at Blanco A is based on a replacement capital cost of $3,043,061 for a replacement engine.[70] This value is too low. If EPNG were to replace the two units with a single engine based on the site rating, this would cost nearly $15 million, which greatly exceeds the Draft SIP Revision's input cost for the replacement ($6,086,122 for two engines).[71] This change would make replacement far less cost-effective and would exceed the $10,000/ton threshold set by NMED.

Additionally, even using many of NMED's same assumptions, replacement still costs more than $10,000/ton because NMED made critical errors for two assumptions. First, NMED used the wrong measure of inflation to scale up costs from an estimate EPNG provided on September 8, 2020. EPNG's estimate calculated the capital cost based on $/hp and the permitted hp of each engine ($3,227/hp x 943 hp), and this cost estimate was in 2020 dollars. Since that time, costs have gone up dramatically. To calculate the replacement cost in 2023 dollars, NMED used the U.S. Bureau of Labor Statistics' CPI inflation calculator. However, per the U.S. Bureau of Labor Statistics website, the calculated data for that inflation measure represents changes in the prices of all goods and services purchased for consumption by urban ***households***. This method is not suitable for estimating changes in capital cost of industrial machinery like natural gas-fired engines. Rather, the appropriate method to calculate the change in replacement capital cost is by using the Chemical Plant Cost Indexes. The published Chemical Plant Cost Indexes for calendar year 2020 and calendar year 2023 are 596.2 and 797.9, respectively, which amounts to an approximate 33.8% increase in capital cost from the 2020 estimate that EPNG provided. This cost increase is consistent with the $/hp increase that EPNG has experienced for natural-gas fired engines over that timeframe.

Second, NMED assumed the other indirect annual cost of the replacement engine is $0.[72] This is contrary to EPA's Control Cost Manual, which suggests that other indirect annual costs should be set at 4% of the total capital investment cost.[73]

By using the Chemical Plant Cost Indexes and with the addition of the other indirect annual cost of the replacement engine, the cost effectiveness in 2023 dollars for the two units at Blanco A

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[70] Draft SIP Revision, Attachment D, at 211.

[71] *See* Attachment 2 (Blanco A cost data).

[72] Draft SIP Revision, Attachment D, at 211.

[73] EPA, Cost Estimation: Concepts and Methodology, Chapter 2, at 35 (Nov. 2017), https://www.epa.gov/sites/default/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf (noting that other indirect costs, such as taxes, insurance, and administrative charges and permitting costs are "usually combined into a single, 4% factor" "from the system total capital investment"); *see also id.* at 13 (noting that administrative charges are an element of fixed annual costs).



(units A-11 and A-13) are $10,501 and $12,895, respectively.[74] Both cost values exceed NMED's cost threshold of $10,000, and these units should therefore not be subject to emissions-rate limits for that reason alone.

Finally, the $/ton values provided above are derived by only changing two of NMED's input assumptions (capital cost inflation and indirect annual costs). Going even further and correcting for NMED's flawed use of inflated baseline emissions and assumed emissions reduction quantities, the $/ton using the proper BAE amounts for A-11 and A-13 (of 21.28 tpy and 14.76 tpy, respectively, as shown in Table 2) results in costs dramatically exceeding $10,000/ton. A-11 and A-13 would have costs of $29,780/ton and $44,210/ton, respectively.[75]

5. Blanco Conclusion

In this last subsection, EPNG sets forth the four-factor analysis that should apply to Blanco A if the errors in NMED's methods and assumptions are corrected.

Because NMED used emission test data from 2022 to 2023 in establishing the BAE rate (in lb/hr), EPNG has expanded the lookback period from 2015-2019 to 2015-2023 when reviewing emission test data for Blanco A Compressor Station. Additionally, consistent with NMED's methodology, EPNG is using the average test results of that period. EPNG recalculated the cost effectiveness using the average emission test data from 2012-2023 by engine and the average actual hours from 2016 to 2021 by engine, as provided in Table 2. Incorporating the above points on emission calculations, the appropriate BAE for Blanco A Compressor Station is as follows:

Table 2. – Blanco A Baseline Actual Emissions

Unit ID	NOx EF (lb/hr) Based on the Average Test Data (2012-2023)	Operating Hours (hr/yr) Based on the Average Annual Hours (2016-2021)	Baseline Actual Emissions (tpy)
A-1	4.47	3120	6.97
A-2	7.52	1312	4.93
A-3	7.09	3277	11.62
A-4	1.58	2275	1.80
A-5	5.66	50	0.14
A-6	6.43	1297	4.17
A-7	6.57	3698	12.15
A-8	7.24	1	0.00
A-9	8.49	2307	9.79
A-10	6.04	2	0.01
A-11	7.02	6065	21.28

[74] *See* Attachment 8, Blanco A Replacement Cost Scenarios (showing calculation methodology).

[75] *See id.* (showing calculation methodology).

A-12	7.83	631	2.47
A-13	5.99	4931	14.76
A-14	1.57	1762	1.38

Furthermore, considering the revised BAE numbers and the O&M, AFUDC, and capital costs, EPNG computes the final cost per ton for Blanco A Compressor Station as follows in Table 3:

Table. 3 – Cost Analyses for Low Emission Combustion at Blanco A

Unit ID	Total Annualized Cost ($) – LEC1	Total Annualized Cost ($) – LEC2	Total Annualized Cost ($) – LEC3	Cost Effectiveness ($/ton) – LEC1	Cost Effectiveness ($/ton) – LEC2	Cost Effectiveness ($/ton) – LEC3
A-1	$367,750	$542,730	$500,805	NA	$145,642	$93,647
A-2	$348,694	$523,674	$481,749	$414,120	$146,677	$113,291
A-3	$369,506	$544,486	$502,561	$264,298	$66,312	$50,691
A-4	$358,753	$533,733	$491,808	NA	NA	$799,896
A-5	$335,504	$510,484	$468,559	NA	$5,730,671	$4,076,698
A-6	$348,531	$522,977	$481,052	$2,782,020	$185,385	$137,641
A-7	$373,680	$548,660	$506,735	$603,980	$66,060	$49,548
A-8	$334,992	$509,972	$468,047	$696,865,144	$347,116,726	$189,556,768
A-9	$359,114	$534,094	$492,169	$138,301	$72,250	$57,287
A-10	$334,999	$509,979	$468,053	NA	$134,345,216	$97,670,156
A-11	$398,509	$573,489	$531,564	$168,247	$38,288	$29,318
A-12	$341,576	$516,556	$474,631	$679,891	$284,838	$221,657
A-13	$386,637	$561,617	$519,692	NA	$58,288	$42,604
A-14	$353,397	$528,377	$486,452	NA	NA	$1,040,483

Note – “NA” no additional emissions reduction beyond baseline will occur so cost effectiveness cannot be calculated.

Detailed calculations are presented in Enclosure 1 to EPNG’s letter of January 19, 2024, which is provided as Attachment 1 here.

EPNG requests that NMED reflect these calculations in its petition for a public hearing with EIB, which would mean removing all Blanco A units from the proposed SIP for exceeding the cost threshold of $10,000/ton.

C. Pecos River Critique

As explained in this subsection, the cost-effectiveness calculations for the installation of SCR at the Pecos River turbines suffers from multiple erroneous assumptions. Once these erroneous assumptions are corrected, the cost-effectiveness calculations for SCR go up from NMED’s assessed $6,000/ton for unit A-02 and $7,000/ton[76] for A-03 to $26,790/ton and $28,369/ton,

[76] Draft SIP Revision, at 112.



respectively. Those corrected values are far in excess of NMED's selected $10,000 cost-effectiveness threshold, and these units should therefore be excluded from any emissions limits under the SIP revision process.

1. Capital Costs

NMED used the EPA SCR workbook to calculate the capital cost to be $2,875,450 for the SCR and $2,975,000 for turbine housing reconfiguration, adjusted to 2023 dollars.[77] In EPNG's comment response to NMED dated January 19, 2024, EPNG relied on the vendor quote of the SCR cost plus costs associated with removing the existing regenerator including all exhaust duct work and installation of a new regenerator equipment.[78] EPNG's estimated capital cost for the SCR is $11,371,394.[79] EPNG's capital estimate is therefore approximately double NMED's, which affects the overall cost-per-ton value. For the reasons discussed below, EPNG's more accurate estimated capital cost of $11,371,394 must be used by NMED.

NMED relied heavily on default values reported in the EPA SCR workbook in its cost estimate calculations. That approach is unreliable and problematic because the SCR workbook is not suited to predict SCR costs for the turbines at Pecos River. The EPA Cost Control Manual section states that the "procedures for estimating costs presented in this report are based on cost data for SCR retrofits *on existing . . . boilers for electric generating units larger than 25 Mwe (approximately 250 MMBtu/hr)*."[80] Thus, the estimate is for boilers—not turbines. That is an entirely different piece of equipment than a turbine. The procedures to estimate capital costs are not directly applicable to sources other than utility and industrial boilers. For example, EPA states that "[c]apital cost equations are provided for both coal-fired and oil- or gas-fired units. The capital cost equations are applicable to coal-fired utility boilers and to oil- or gas-fired utility boilers at facilities with generating capacity greater than or equal to 25 MW. Equations are also provided for coal-fired and oil- or gas-fired industrial boilers with a heat input capacity greater than approximately 250 MMBtu/hr."[81]

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[77] Draft SIP Revision, Appendix D, at 285.

[78] Attachment 1 (January 19 Letter), at pdf page 36.

[79] *See* Attachment 7, SCR Cost Analysis and Vendor Capital Quote. While the analysis and vendor quote are for turbines at Caprock Compressor Station, the cost of SCR for the turbines at Pecos River is reflected by this estimate as well, given the similar unit and facility design. It should also be noted that the SCR capital cost would only have increased since this time, given the increase in the Chemical Plant Cost Indexes discussed above. This capital cost was used to support the analysis in the January 19, 2024 letter to NMED, but EPNG plans to present an updated vendor estimate for the hearing, should NMED continue proposing SCR at Pecos River.

[80] Control Cost Manual, Chapter 2, Selective Catalytic Reduction, at 6 (June 2019), https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf (emphasis added).

[81] *Id.* at 66.

The capital cost equations listed in the Control Cost Manual include the following applications: (1) coal-fired utility boilers greater than or equal to 25 MW; (2) oil- or gas-fired utility boilers range from 25 MW to 500 MW; (3) coal-fired industrial boilers greater than or equal to 250 MMBtu/hr; (4) oil-fired industrial boilers range from 275 MMBtu/hr and 5,500 MMBtu/hr; (5) gas-fired industrial boilers range from 205 MMBtu/hr and 4,100 MMBtu/hr; and (6) gas-fired industrial boilers greater than 4,100 MMBtu/hr.[82] Note that these are all for ***boiler*** units with capacity of at least 205 MMBtu/hr.

By comparison, the gas-fired turbines at Pecos River each have a maximum heat input of 56.45 MMBtu/hr at site elevation, far below the 205 MMBtu/hr minimum evaluated in the EPA SCR workbook and the EPA Control Cost Manual. And, capital costs do not necessarily scale with unit size because of certain size-invariant capital costs. Furthermore, the EPA Control Cost Manual SCR methodologies are developed for utility and industrial boilers, not turbines. Similarly, none of the cost equations in EPA Control Cost Manual are applicable to the turbines at Pecos River. Last, even if using boiler SCR costs to calculate costs for turbines was an accurate approach (which it is not), the cost formulas in the Cost Control Manual rely on outdated studies from the late 1990s and early 2000s. For all these reasons, NMED must rely on a recent vendor quote to estimate the SCR cost as opposed to relying on EPA SCR workbook to meet minimum standards of rational agency decision-making.

In the EIB's recent 2021 ozone rulemaking (part 20.2.50 NMAC), EPNG provided vendor quotes for SCR modifications at a similar facility in New Mexico, which information was accepted and relied on by NMED and EIB. These same numbers are appropriate for use in the four-factor analysis for Pecos River. Indeed, the 2019 EPA Guidance notes that vendor estimates are preferrable, stating: "We recommend that *states exercise caution before accepting or rejecting controls based on generic cost estimates if adequately documented source-specific estimates are available or can be prepared.*"[83] There is no reason NMED should reject this reliable cost data in the context of Regional Haze.

The 2019 EPA Guidance reflects the fact that source-specific vendor estimates are the best source of information available on a specific cost of control. That is why the 2019 EPA Guidance explains that "states may quantify control costs for particular types of control equipment by using generic cost estimates or estimation algorithms" "when site-specific cost estimates are not available," clearly demonstrating that site-specific estimates are preferrable.[84] Given that the Control Cost Manual's estimates are for large boilers (not turbines), the source-specific estimates are even more preferrable.

NMED's estimate of the cost of SCR installation using the EPA SCR Tool is unreliable for natural gas turbines for the reasons described herein, and NMED should instead use the capital cost $11,371,394.

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[82] *Id.* at 68-74.

[83] 2019 EPA Guidance, at 32 (emphasis added).

[84] *Id.*

2. Baseline Emissions Calculations and Cost-Effectiveness Result

While EPNG agrees that the BAE in tons per year ("tpy") calculation should be based on the representative annual operating hours from 2016-2021, EPNG disagrees with NMED on how the baseline NOx hourly emission rate (lb/hr) was established.

In the cost estimate, NMED adjusted turbines' tested NOx emission rates to 100% load assuming a linear relationship between NOx emission rate and percent load.[85] Figure 4, below, shows NMED scaled up Pecos River Unit A-01 June 2023 tested NOx emission rate from 22.4 lb/hr to 39.5 lb/hr assuming a linear relationship between percent load and NOx emission rate.[86] To establish the BAE in the cost estimate, NMED assumed the turbines will operate at 100% load at all time. In doing so, NMED artificially inflated the NOx BAE for these units.

As demonstrated in EPNG's comment response to NMED dated January 19, 2024, the NOx emission rate for turbines does not increase linearly with percent load as shown in Figure 5, below.

Next, while NMED used only the single most recent test data from 2023 to establish the baseline emission rate, EPNG reviewed and used the available test data over the period of 2016-2022. The average test results over this 2016-2021 period, as shown in Table 4, are more appropriate for establishing the BAE, to be consistent with the representative annual operating hours from 2016-2021.

Last, NMED used the ISO rating (expressed at sea level elevation and 59 degrees F) of the turbines to scale up the emission factors. However, that approach does not reflect actual operating conditions, making it less representative and less accurate. Pecos River is located at an elevation of 2,900 feet and has much higher average daytime temperatures. Because of the lower air density and resulting lower mass of air flow, power generated by turbines decreases in warmer temperatures and higher elevations. Based on GE power curves depicting this relationship, when fully loaded, the units will operate at a lower horsepower ("HP") at Pecos River than compared to the sea level ISO rating of 7,150 HP. If emission factors are to be scaled, the appropriate basis for scaling is the unit site rating of 5,650 HP, which is approximately 80% of 7,150 HP. For all the reasons above, EPNG recommends that the use of the inflated NOx emission rate be discarded, as it is not representative of BAE. In fact, NMED's estimated NOx emissions reductions (in tpy) *with* SCR control are higher than the Pecos River reported *annual* NOx emissions from 2016-2021,[87] further demonstrating that NMED's estimated NOx BAE are indeed the equivalent potential emissions.

The alternative BAE and cost effectiveness calculations recommended by EPNG are summarized in Table 4 below. EPNG provided similar substantive comment in its January 2024 letter.

[85] NMED Draft SIP Attachment C, page 54.

[86] *See id.*

[87] Draft SIP Revision, Appendix C, at 57.

El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

Table 4. – Pecos River Units A-01, A-02, A-03 Cost Effectiveness Results

Unit No.	Average NOx Emissions (2016-2021) (lb/hr)	Representative Annual Operating Hours (hr/yr)	NOx BAE (tpy)	Annualized Cost (2023$)	Estimated NOx Reduction[1] (tpy)	Cost Effectiveness ($/ton)
A-01	22.1	3553	39.3	$1,037,467	27.5	$37,750
A-02	25.6	6378	81.7	$1,532,106	57.2	$26,790
A-03	27.5	5537	76.2	$1,511,879	53.3	$28,369
1. Based on 70% control efficiency for SCR.						

Figure 4. – NOx Emission Rate (lb/hr) versus Load

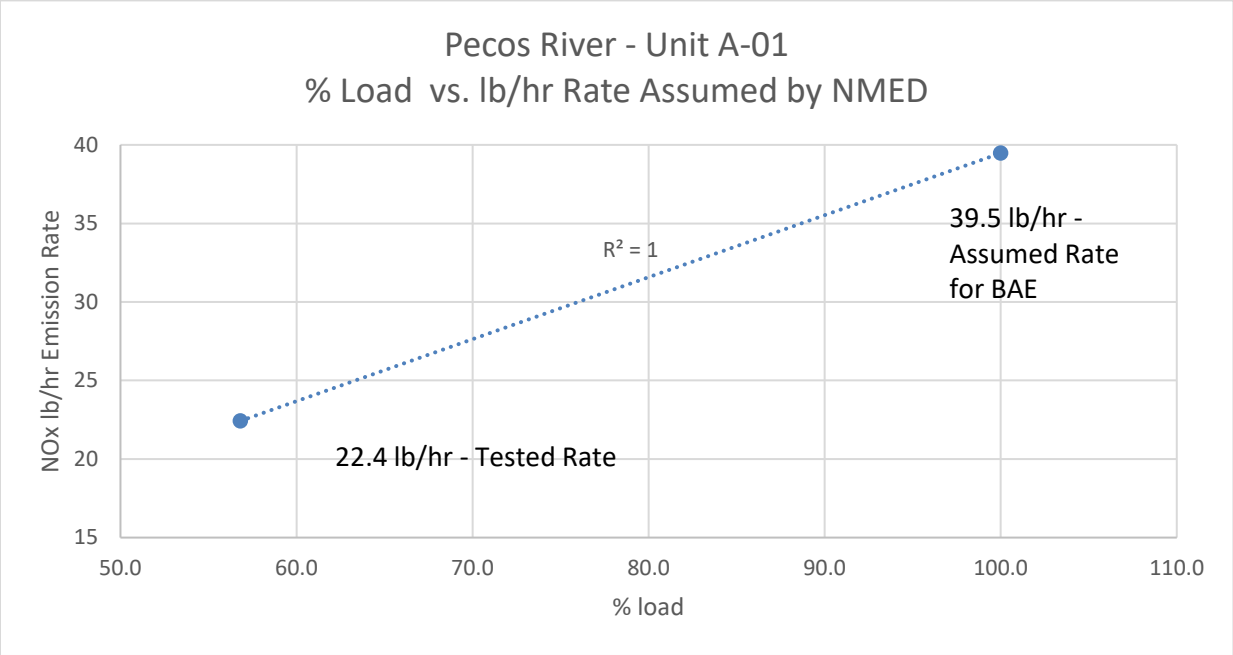
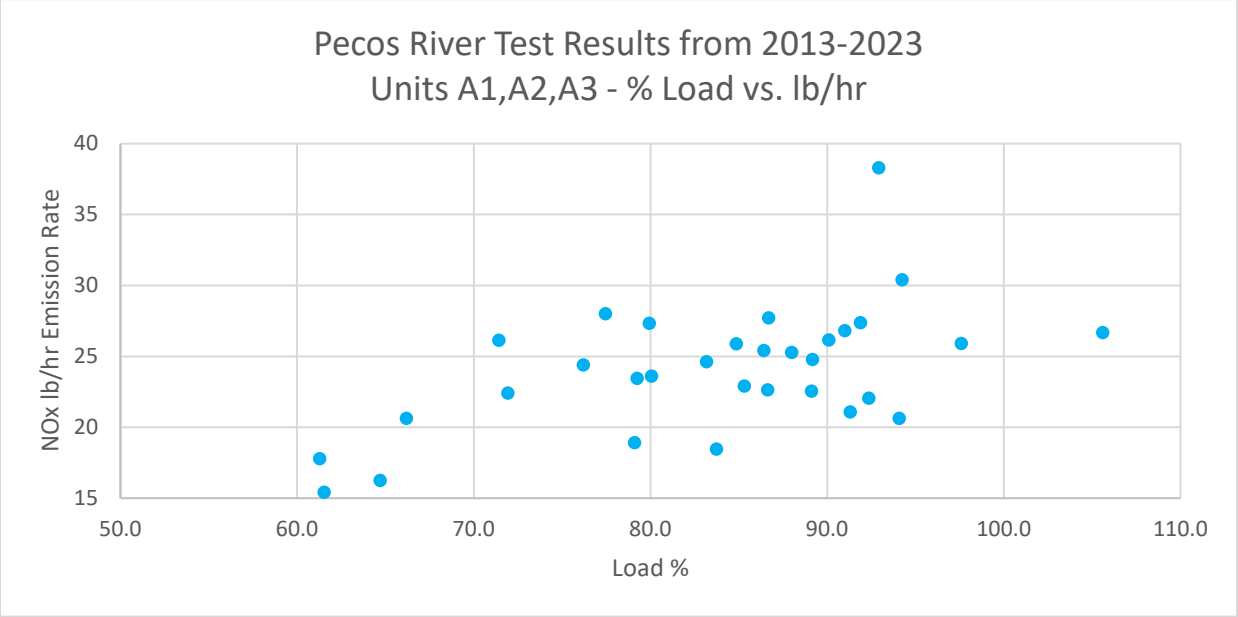


Figure 5. – Pecos River Test Results from 2013 -2023 for Units A-01, A-02, A-03



3. SCR Efficiency

NMED cited an SCR efficiency rating of 90% its four-factor analysis calculations.[88] This efficiency rating is not representative and is an overestimate for turbine-driven natural gas transmission compression, including the turbines at Pecos River.

As shown in the EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, the optimum temperature for SCR efficiency depends on both the type of catalysts used in the process and the flue gas composition.[89] For the majority of commercial catalysts, the operating temperatures for the SCR process range from 480 to 800 degrees F. Figure 2.2 from the EPA Control Cost Manual's Chapter 2, provided as Figure 6 below, is a graph of the NOx removal efficiency as a function of temperature for a typical metal oxide catalyst. The figure shows that the rate of NOx removal increases with temperature up to a maximum between 700 and 750F. As the temperature increases above 750F, the reaction rate and resulting NOx removal efficiency begin to decrease. The compressors at Pecos River CS typically have an exhaust temperature between 500 and 580F. Per Figure 6, below, from the EPA Control Cost Manual, SCR efficiency in the temperature range for the Pecos River turbines is closer to between 63% and 73%.

In EPNG's initial Four-Factor Analysis Report submitted on November 1, 2019 and the January 19, 2024 comment response to NMED, EPNG cited a 70% reduction efficiency for SCR as a

[88] *See* Draft SIP Revision, at 139 nn.22-23.

[89] Control Cost Manual, Chapter 2, Selective Catalytic Reduction, at 20 (June 2019).

conservative estimate.[90] NMED has not provided a reasoned response or other basis for selecting a 90% reduction efficiency, which is only achieved in a narrow temperature band.

Figure 6. – SCR Control Efficiency Vs. Temperature, EPA Control Cost Manual

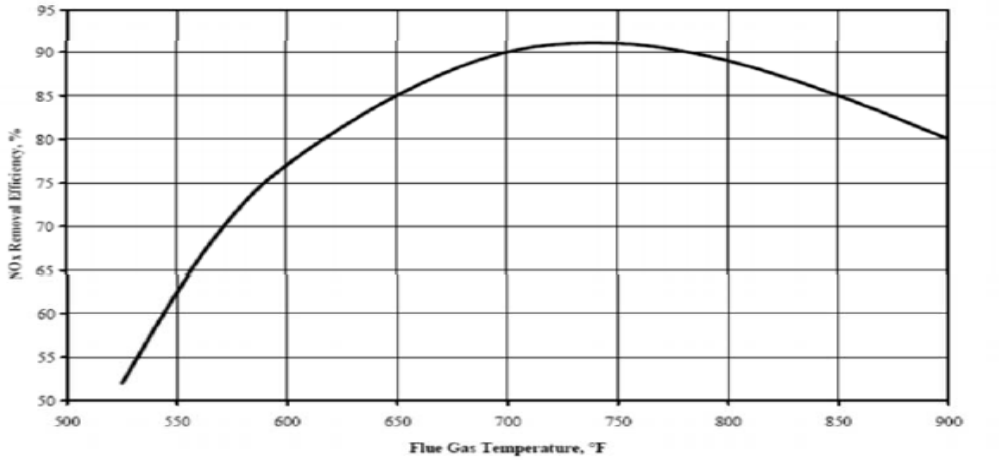


Figure 2.2: NO_x Removal versus Temperature [50]

4. Additional O&M Cost

While NMED relied heavily on outdated default values reported in EPA SCR workbook to estimate the additional O&M Costs,[91] EPNG relied on the more accurate vendor quotes for primary parts associated with the SCR controls. In its January 19, 2024 letter, EPNG updated the additional O&M costs based on vendor quotes received in Q3 2021 for reagent consumption and cost, as well as maintenance, labor, electricity, and catalyst replacement costs.[92] For example, to calculate the annual reagent cost, NMED used the EPA SCR workbook's default value of $0.293/gallon for 29% ammonia solution.[93] The $0.29/gallon ammonia solution cost is based on an outdated average for 2016 per USGS Mineral Commodity Summaries, January 2017.

Contrary to NMED's approach, the EPA SCR workbook notes that the user should use the actual value, if known.[94] The August 2021 quote received by EPNG from an aqueous ammonia vendor

[90] *See* Attachment 1 (January 2024 Letter), at 7-8; Draft SIP Revision, Attachment D, at 2-4 through 2-5.

[91] Draft SIP Revision, Appendix D, at 285.

[92] *See* Attachment 1 (January 2024 Letter), at 7.

[93] EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, at 90 n.34.

[94] *See id.* at 90 n.33 ("When estimating direct annual operating costs, the current price of these commodities reflecting the year in which the cost estimate is made should be used. Catalyst and reagent prices can be obtained from vendors.").

was $1.80/gallon.[95] Although EPNG provided this actual value of ammonia solution in the January 19, 2024 response to NMED, NMED failed to update the annual O&M cost.

Further, NMED's approach failed to account for the catalyst cost required for SCR.[96] The catalyst would cost approximately $200,000 and would last for four years, representing an approximate $50,000 annual cost that must be reflected in the cost analysis.[97]

5. Other Indirect Annual Cost – Administrative, Insurance, and Taxes

In NMED's draft final control cost evaluations spreadsheet, Other Indirect Annual Costs ("OAC") are listed at $2,799 per unit. Costs should be slightly higher based on the vendor quote for the capital investment cost. The appropriate costs are shown in Table 5.

Table 5. – Pecos River Units A-01, A-02, A-03 Annual Administrative Costs

Cost type	Unit A-01	Unit A-02	Unit A-03
Administrative Costs	$3,059	$3,310	$3,310

These costs were incorporated into the detailed calculations in the January 2024 letter, in Enclosure 2A.[98] NMED did not incorporate these costs in its four-factor analysis for the Pecos River units.[99] These costs must be included.

6. Pecos River Emission-Rate Limits

In the proposed addition to 20.2.68 NMAC, NMED proposes NOx emission-rates limits of 3.64 lb/hr for Pecos River Unit A-02 and 4.05 lb/hr for Unit A-03. These limits are based on the assumption that SCR will achieve a 90% reduction efficiency. However, consistent with the discussion in Section V.B.3., above, that emission-rate limit is based on the optimal temperature range for SCR efficiency and not the actual exhaust gas temperature for the two Pecos River units. It is therefore not realistic, and the final rate should not be set at a value Pecos River cannot achieve. The CAA contemplates that requirements imposed on sources will be feasible to achieve. Indeed, throughout the Draft SIP Revision, NMED analyzed feasibility of controls, demonstrating feasibility is a critical consideration. As discussed above, a 90% reduction efficiency is infeasible at the Pecos River units and must be eliminated from consideration.

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[95] *See* Attachment 3 (SCR Reagent Vendor Quote) (while the per-gallon cost is $1.35, shipping costs are $2,700 per 6,000-gallon load, equating to $0.45/gallon, for a total cost of $1.80/gallon).

[96] *See* Draft SIP Revision, Appendix D, at 285.

[97] *See* Attachment 1, at pdf page 30 (showing annual catalyst replacement costs of $42,912, $51,371, and $45,601 for Units A-01, A-02, and A-03, respectively).

[98] *See id.*

[99] *See* Draft SIP Revision, Attachment C, at 57 (showing cost inputs from EPNG that NMED adopted); *id.* Attachment D, at 285 (showing lower administrative costs than those shown here).



7. Pecos River Alternative Emissions Standard Under 20.2.50.113 NMAC

Pecos River Units A-01, A-02, and A-03 are all part of an approved Alternative Emissions Standard ("AES") under the New Mexico Ozone Precursor Rule, 20.2.50.113 NMAC, which was conditionally approved on June 26, 2023 by the AQB.[100] These units qualified for an AES based on economic infeasibility because of their high cost-per-ton of emissions reductions. The cost-per-ton assessed for units A-02 and A-03 in the request for the AES was $22,517 and $26,527, respectively, based on actual emissions, and $11,097 for both based on potential to emit.[101] All these values exceed the $10,000/ton threshold selected by NMED.

NMED's approval, through AQB, of the AES cost assessment just last year represents, per the Ozone Precursor Rule, a finding that "it is not . . . economically feasible for the individual engine or turbine to achieve the emissions standards."[102] NMED should not deviate from this finding now, as doing so would be "arbitrary, capricious or an abuse of discretion" or "not supported by substantial evidence in the record."[103]

8. Ammonia Use Required for SCR Presents Its Own Environmental Drawbacks.

As noted above, one of the four factors in the four-factor analysis requires consideration of other "environmental impacts of compliance."[104] This is notable because SCR presents its own *additional* environmental issues.

First, and as discussed above, an SCR system must maintain precise operational parameters to generate as complete of a reaction as possible. And even when these parameters are closely controlled, some level of ammonia does not react and joins the exhaust stream.[105] This is referred to as "ammonia slip."[106] Ammonia is itself an unhealthy gas to inhale for humans and animals, and ammonia can react with other atmospheric constituents that turn into other harmful

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[100] *See* Attachment 4, AQB Letter Conditionally Approving AES (June 26, 2023). The approval was conditional "to the extent that, when any turbine is permanently replaced, the replacement turbine shall be considered 'new' pursuant to the rule." *Id.* at 1.

[101] *See* Attachment 5, Barr, New Mexico Alternative Emission Standards Proposal (Rev. April 2023), at 16 tbl. 4-1. The analysis for the AES used some different assumptions than EPNG's four-factor analysis, which are detailed in Attachment 6, Summary of Assumptions. For example, the AES used a 3.25% interest rate and a 25-year useful life, as opposed to an 8.53% interest rate and 20-year useful life. These differences contribute to EPNG's cost-per-ton estimate for the AES being lower than its estimate for the four-factor analysis.

[102] 20.2.50.113(B)(11)(a) NMAC.

[103] NMSA 1978, § 74-2-9(C)(1)-(C)(2).

[104] 42 U.S.C. § 7491(g)(1).

[105] ThermoFisher Scientific, *Reducing NH3 in Selective Catalytic Reduction* (July 16, 2019), https://www.thermofisher.com/blog/identifying-threats/reducing-nh3-slip-in-selective-catalytic-reduction-scr/ ("The reaction between NOx and NH3 is never perfect[.]").

[106] Control Cost Manual, Chapter 2, Selective Catalytic Reduction, at 23.



substances, like ammonium sulfates.[107] Further, ammonia plays a role in $PM_{2.5}$ formation, which itself has the potential to impact visibility.[108] Thus, ammonia slip itself is an environmental impact that should be considered under the four-factor analysis.

Second, SCR requires the continuous use of an ammonia solution to reduce NOx in the exhaust gas stream.[109] The amount of solution required varies by a unit's annual usage hours. Potentially thousands of gallons per year would be shipped to the facility via tanker trucks over local roads, and storage onsite in a large tanks. The ammonia solution requires safe storage, handling and disposal in compliance with state and federal regulation to avoid harm to the environment. These requirements include those under the Community Planning and Right-to-Know Act (including reporting obligations) and the Comprehensive Environmental Response, Compensation, and Liability Act, along with additional state-level requirements.[110] In addition to environmental requirements, the facility would be required to comply with applicable process safety management requirements applicable to chemicals such as ammonia.[111] While EPNG would, of course, aim to responsibly handle such materials consistent with applicable laws, it is not within the Company's practice or protocol to unnecessarily increase the frequency of handling chemicals like ammonia. Additionally, EPNG has no control over the safety of ammonia solution and byproducts thereof when in shipment.

Despite these environmental impacts, NMED's evaluation of SCR states that there are no significant energy and environmental impacts from requiring SCR installation at Pecos River.[112] NMED has therefore failed to consider an important aspect of the problem at this stage, which would result in arbitrary and capricious action if left uncorrected and if the final SIP revision requires SCR at Pecos River.[113] And even if a consideration of ammonia slip is still offered, an

[107] *Id.* at 23-24 (noting ammonia in the flue gas "causes a number of problems . . ., including health effects, visibility of the stack effluent").

[108] *See* Wu et al., *$PM_{2.5}$ Pollution is Substantially Affected by Ammonia Emissions in China*, Environmental Pollution (Aug. 20, 2016), https://pubmed.ncbi.nlm.nih.gov/27552041/.

[109] *See* Attachment 7, SCR Cost Analysis and Vendor Capital Quote.

[110] *See, e.g.*, 40 C.F.R. Part 355 Appendix A (listing ammonia as "extremely hazardous substance" under Emergency Planning and Community Right-to-Know Act); 40 C.F.R. § 302.4 (listing ammonia as hazardous substance under reporting requirements in Comprehensive Environmental Response, Compensation, and Liability Act). Under the thresholds listed in these regulations, the amount of ammonia stored onsite would likely require emergency planning, but EPNG has not fully reviewed the extent of the regulatory requirements and their potential application.

[111] *See* 29 C.F.R. § 1910.119 (Occupational Safety and Health Administration (OSHA) process safety management regulations applying provisions to ammonia solution); 40 C.F.R. Part 68 (EPA risk management program modeled after OSHA's program).

[112] *See* Draft SIP Revision, at 112-13 (table showing "none" on the column for "Energy & Non-Air Quality Impacts" for SCR).

[113] *See Bernalillo Cnty. Health Care Grp.*, 2014-NMSC-008, ¶ 9 (Agency action is arbitrary and capricious if the agency failed to consider an important aspect of the problem or offered an explanation that runs counter to the evidence.).



agency must still reasonably explain why environmental concerns about ammonia usage do not outweigh the other factors.

9. Pecos River Conclusion

In this last subsection, EPNG sets forth the cost-effectiveness values that should apply to Pecos River if the errors in NMED's methods and assumptions are corrected.

Considering the above points, the cost-per-ton values for NOx emissions reduced for Pecos River units A-01, A-02, and A-03 should be: $37,750, $26,790, and $28,369, respectively. Based on these values, none of the Pecos River units should be subject to any emissions limits under the SIP Revision. EPNG requests that NMED reflect this fact in its petition for a public hearing with EIB to avoid promulgating an arbitrary and capricious rule based on demonstrably false assumptions.

VI. Washington Ranch Four Factor Analysis

While EPNG does not agree with all the methodological choices (or consideration of replacement) used for the Washington Ranch four factor analysis, EPNG does agree with the bottom-line conclusion that the cost of emissions reductions would exceed $10,000/ton. Accordingly, EPNG agrees that no emissions limits should be imposed on units at Washington Ranch. Notably, if NMED had used proper assumptions for Washington Ranch, then the cost of emissions reductions therefrom would be even higher than NMED assessed.

However, EPNG does not oppose an emissions rate limit of 3.0 g/hp-hr based on *existing* controls at Washington Ranch. And no additional controls should be required for Washington Ranch, consistent with the results of NMED's cost-effectiveness analysis for those units.[114]

VII. NMED Should Consider Visibility Improvements In Deciding Whether to Impose Emissions Limits.

Last, even if it was reasonable and consistent with EPA guidance to subject Blanco A and Pecos River to a four-factor analysis (which it was not), final emissions limits do not need to be selected for these sources, considering visibility conditions and projected improvements compared with the costs of the controls (even using the faulty $/ton values that NMED assessed).

As the 2019 EPA Guidance explains, there are additional factors that states may consider in determining whether to ultimately impose emissions controls under the RHR to make reasonable progress toward reaching natural visibility conditions. Quite naturally, visibility conditions is one such factor: "[B]ecause the goal of the regional haze program is to improve visibility, it is

[114] Indeed, the cost-effectiveness evaluation for the units at Washington Ranch suffers from some of the same errors as those described above for Blanco A and Washington Ranch. Even with those errors, NMED's analysis still shows that the units at Washington Ranch have no cost-effective incremental control options, further confirming that additional controls are not reasonable at that facility.

reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal."[115] In the 2019 EPA Guidance, EPA therefore "interpret[ed] the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other [four] factors when determining whether a measure is necessary to make reasonable progress."[116] The 2021 Clarification confirms this interpretation, noting: "Another potentially reasonable approach might be for a state that identifies cost-effective new controls at a multitude of sources to choose to require controls at only a subset of those sources that constitute the vast majority of the visibility benefit."[117]

In considering actual visibility benefits against costs of controls, controls should not be required at Blanco A or Pecos River. As the Draft SIP Revision notes, all but one Class I area in New Mexico is projected to be below the uniform rate of progress glidepath toward natural visibility conditions by 2064.[118] The one exception is the Salt Creek Wilderness Area, but that is not the closest Class I area for either Blanco A or Pecos River. Thus, consistent with the 2021 Clarification, NMED can simply require controls "at only a subset of those sources that constitute the vast majority of the visibility benefit."[119]

Further supporting this position, as explained *supra* note 59, Blanco A and Pecos River are relatively small emissions sources of NOx and SO2 combined, and their emissions of SO2 are *de minimis*. Given the predominance of ammonium sulfate as the aerosol species with the greatest visibility impacts at all New Mexico Class I areas and at Mesa Verde, reductions of NOx emissions from Blanco A and Pecos River are not required to make reasonable progress. And even accepting NMED's (erroneous) cost-per-ton estimates for these sources, they are still in the upper range of the threshold that NMED identified for determining cost-effectiveness. That $10,000/ton threshold can be balanced against the actual expected visibility benefits that would occur.

Accordingly, after considering projected visibility conditions in New Mexico, emissions limits on Units A11 and A13 at Blanco A and Units A-02 and A-03 at Pecos River Blanco A are not required to make reasonable progress under the RHR.

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[115] *Id.* at 36-37.

[116] *Id.* at 37.

[117] 2021 Clarification, at 13. *See also id.* ("While the CAA lists the four reasonable progress factors, it is silent as to whether states or the EPA may consider other, additional factors. This final rule neither requires nor prohibits states from considering visibility when making reasonable progress determinations. . . . However, a state that elects to consider an additional factor such as visibility benefit must consider it in a reasonable way that does not undermine or nullify the role of the four statutory factors in determining what controls are necessary to make reasonable progress." (citing Response to Comments on Protection of Visibility, at 186)).

[118] Draft SIP Revision, at 169 ("The future year visibility on the MID at each Class I Area in New Mexico is projected to be below the URP glidepath adjusted for international emissions and wildland prescribed fire, except for Salt Creek Wilderness area.")

[119] 2021 Clarification, at 13.

VIII. Conclusion

Based on the arguments presented herein, NMED should not impose any emissions rate limits on EPNG's units at Blanco A or Pecos River. For Washington Ranch, EPNG does not oppose the 3.0 g/hp-hr emission rate limit proposed for Units 1 and 2 based on existing controls, but no additional controls should be required for those units, consistent with NMED's cost-effectiveness evaluation. EPNG therefore requests that NMED not propose any emission limits for the units at Blanco A and Pecos River in its petition for a public hearing with EIB.

If you have any questions about our response, please contact Weiwen Daly by email at Weiwen_Daly@kindermorgan.com or by phone at 303-914-7616 or me by email at Tom_Mitchell@kindermorgan or by phone at 713-420-3463.

Sincerely,

/s/ Thomas Mitchell

R. Thomas Mitchell
Manager, EHS

Attachments:

- Attachment 1: Letter from R. Thomas Mitchell, El Paso Natural Gas Company, L.L.C. to Ms. Kirby Olson, Planning Section Chief, Air Quality Bureau (January 19, 2024).
- Attachment 2: Blanco A Cost Support (Sept. 5, 2024).
- Attachment 3: SCR Reagent Vendor Quote (August 2021).
- Attachment 4: Letter from Cindy Hollenberg, AQB Compliance and Enforcement Section Chief, to Weiwen Daly, Kinder Morgan, Inc., Conditionally Approving AES (June 26, 2023).
- Attachment 5: Barr, New Mexico Alternative Emission Standards Proposal (Rev. April 2023).
- Attachment 6: Document Summarizing Differences in Cost-Effectiveness Analysis Parameters Between Alternative Emissions Standard Demonstration and Four-Factor Analysis for Pecos River.
- Attachment 7: SCR Cost Analysis and Vendor Capital Quote.
- Attachment 8: Blanco A Replacement Cost Scenarios.

ATTACHMENT 1

Letter from R. Thomas Mitchell, El Paso Natural Gas Company, L.L.C. to Ms. Kirby Olson, Planning Section Chief, Air Quality Bureau (January 19, 2024)

El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

via Email Only

19 January 2024

Ms. Kirby Olson
Planning Section Chief
Air Quality Bureau
New Mexico Environment Department
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

RE: Draft Final Evaluations, EPA's Regional Haze Rule, El Paso Natural Gas Company, LLC's Blanco Compressor Station A, Pecos River Compressor Station, and Washington Ranch Storage Facility

Dear Ms. Olson:

El Paso Natural Gas Company, L.L.C. (EPNG) appreciates this opportunity to review and comment on the draft final control cost evaluations for the Regional Haze Second Planning Period provided by the New Mexico Environment Department (NMED) for the Blanco Compressor Station A, Pecos River Compressor Station, and Washington Ranch Storage Facility. Below, we provide comments unique to each facility followed by some general comments.

I. Washington Ranch Storage

Other than the common comments provided above, no additional comments are submitted as NMED has agreed that LEC is already installed, and the evaluation demonstrated that electrification and replacement are not cost effective by any metric.

II. Blanco A Compressor Station

A. Emissions Calculations

As a threshold matter, EPNG wishes to clarify that regarding the use of potential emissions versus actual emissions, NMED is directed to use actual emissions when calculating cost-effectiveness of controls, consistent with EPA's Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (at 17) where EPA provided as follows:

> Generally, we recommend that a reasonably projected actual level of source operation in 2028 be used to estimate 2028 actual emissions for purposes of selecting sources for control measure analysis. Source operation during a historical period can inform this projection, but temporary factors that suppressed or bolstered the level of operation in the historical period should be considered, along with factors that indicate a likely increase or decrease in operation.

This is also consistent with the approach for Best Available Retrofit Technology (BART). EPA provided in its BART guidelines as follows: "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing

sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period." 40 C.F.R. Part 50, Appendix Y (Step 4.d.1.).

With regard to how the baseline emissions are calculated, the Clean Air Act (CAA) provides EPA may issue guidance on the calculation of the "baseline amount" as the lower of the average actuals or average allowable over a period of more than one year. Under the presumptive calculation method provided in the CAA, the baseline amount would be considered representative of the source's normal operating conditions. In the PSD rule, "Baseline Actual Emissions" is defined as the average rate of emissions, in tons per year, from a source that actually occurred and is representative of sources in existence on the applicable baseline date. EPA's definition of "baseline actual emissions" enables a source to calculate its baseline rate using the actual operational data from a period other than the period immediately preceding a proposed change in order to select a period of time that is more representative of the source's normal operation. The longer look back period allows the source to consider a full business cycle in setting a baseline actual emission rate that represents normal operation of the source for that time period.

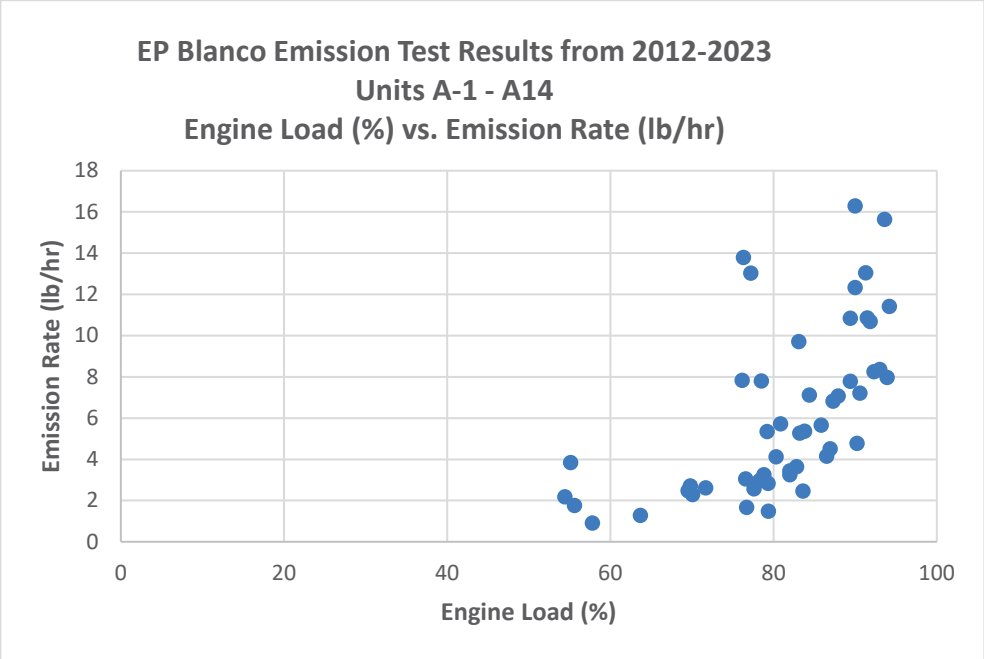
Contrary to EPNG's method, NMED relied on one emission test data (in lb/hr) from the period of 2022-2023 for each of the six units (units A-2, A-3, A-4, A-9, A-11 AND A-13) and then extrapolated it to 100% load to calculate the BAE rate (in lb/hr). For the remaining eight units, NMED used the average of the six units' BAE rates to be the BAE rate for these remaining eight units (in lb/hr). This method of calculating BAE is flawed for the following reasons:

1. The engines at Blanco A Compressor Station operate at variable loads. It is incorrect to calculate the BAE rate assuming the engines operate at 100% load all the time. In fact, these engines rarely operate at 100% load, if at all. Additionally, some engines are restricted by the attached compressors, and they cannot physically operate at 100% load.

2. NMED used six (6) emission test data (one each from units A-2, A-3, A-4, A-9, A-11 and A-13) from the period of 2022-2023 to establish the BAE rates for all 14 units. As stated by EPA, to establish the BAE, a longer look back period is needed to allow the source to consider a full business cycle in setting a BAE rate that represents normal operation for that time period. One emission test data is not representative of normal operation of the source.

3. All units except for units A-8 and A-10 have been tested from the period of 2015-2023. Units A-8 and A-10 were tested in 2012. The BAE rate (in lb/hr) should be based on the actual tested data for each individual unit, not the average test data of some other six units.

4. NMED relied on a linear function of the engine load percent and test data to establish the BAE rate. As demonstrated in the following chart, the relationship between the test data and engine load percent is not a linear function. Emission rate depends on many variables; engine load percent is one of the many variables.



B. Additional O&M Cost

In NMED's draft final control cost evaluations spreadsheet, NMED assumed that the incremental O&M cost of an LEC retrofit is expected to be negligible. EPNG submitted these costs several years ago as part of its initial submissions. Considering the passage of time and the rate of inflation during that time, EPNG obtained up-to-date estimated costs for primary parts associated with the emission controls from the vendor. The additional O&M costs have been updated using the up-to-date vendor estimate and are presented in Enclosure 1.

C. Allowance for Funds Used During Construction (AFUDC)

AFUDC is a generally accepted regulatory accounting method under which the cost of financing the capital construction projects incurred during construction phase is added to the cost of the asset. AFUDC offers a way for the entity to recover its pre-operational financing costs. Including AFUDC in construction projects follows the guidelines for accounting in the Federal Energy Regulatory Commission's Uniform System of Accounts (FERC USOA). Because a FERC regulated entity, such as EPNG, does not earn a return on assets under construction to cover financing costs incurred during the construction period, regulators typically allow entities to capitalize an allowance for funds used during construction for future recovery. EPNG requests that NMED allow the use of AFUDC in its analysis as shown in Enclosure 1.

D. Blanco Conclusion

Because NMED used emission test data from 2022 to 2023 in establishing the BAE rate (in lb/hr), EPNG has expanded the look back period from 2015-2019 to 2015-2023 when reviewing emission test data for Blanco A Compressor Station. Additionally, consistent with NMED's methodology, EPNG is using the average test results of that period. EPNG recalculated the cost effectiveness using the average emission test data from 2012-2023 by engine and the average

actual hours from 2016 to 2021 by engine. Incorporating the above points on emission calculations, EPNG believes that the appropriate BAE for Blanco A Compressor Station is as follows:

Baseline Actual Emissions

Unit ID	NOx EF (lb/hr) Based on the Average Test Data (2012-2023)	Operating Hours (hr/yr) Based on the Average Annual Hours (2016-2021)	Baseline Actual Emissions (tpy)
A-1	4.47	3120	6.97
A-2	7.52	1312	4.93
A-3	7.09	3277	11.62
A-4	1.58	2275	1.80
A-5	5.66	50	0.14
A-6	6.43	1297	4.17
A-7	6.57	3698	12.15
A-8	7.24	1	0.00
A-9	8.49	2307	9.79
A-10	6.04	2	0.01
A-11	7.02	6065	21.28
A-12	7.83	631	2.47
A-13	5.99	4931	14.76
A-14	1.57	1762	1.38

Furthermore, considering the revised BAE numbers and the cost issues of sections 2 and 3 above, EPNG believes the final cost per ton for Blanco A Compressor Station is as follows:

Cost Analyses for Low Emission Combustion

Unit ID	Total Annualized Cost ($) – LEC1	Total Annualized Cost ($) – LEC2	Total Annualized Cost ($) – LEC3	Cost Effectiveness ($/ton) – LEC1	Cost Effectiveness ($/ton) – LEC2	Cost Effectiveness ($/ton) – LEC3
A-1	$367,750	$542,730	$500,805	NA	$145,642	$93,647
A-2	$348,694	$523,674	$481,749	$414,120	$146,677	$113,291
A-3	$369,506	$544,486	$502,561	$264,298	$66,312	$50,691
A-4	$358,753	$533,733	$491,808	NA	NA	$799,896
A-5	$335,504	$510,484	$468,559	NA	$5,730,671	$4,076,698
A-6	$348,531	$522,977	$481,052	$2,782,020	$185,385	$137,641
A-7	$373,680	$548,660	$506,735	$603,980	$66,060	$49,548
A-8	$334,992	$509,972	$468,047	$696,865,144	$347,116,726	$189,556,768
A-9	$359,114	$534,094	$492,169	$138,301	$72,250	$57,287
A-10	$334,999	$509,979	$468,053	NA	$134,345,216	$97,670,156
A-11	$398,509	$573,489	$531,564	$168,247	$38,288	$29,318
A-12	$341,576	$516,556	$474,631	$679,891	$284,838	$221,657
A-13	$386,637	$561,617	$519,692	NA	$58,288	$42,604
A-14	$353,397	$528,377	$486,452	NA	NA	$1,040,483

Note – "NA" no additional emissions reduction beyond baseline will occur so cost effectiveness cannot be calculated.

Detailed calculations are presented in Enclosure 1.

III. Pecos River Compressor Station

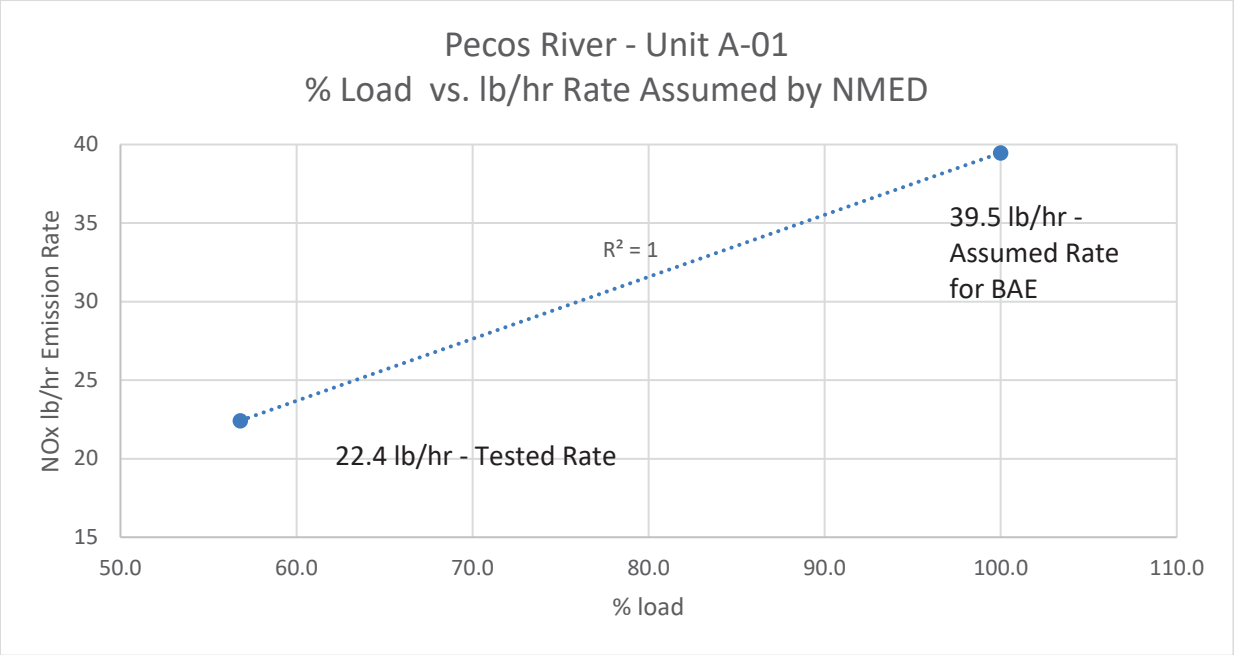
A. Emission Calculations

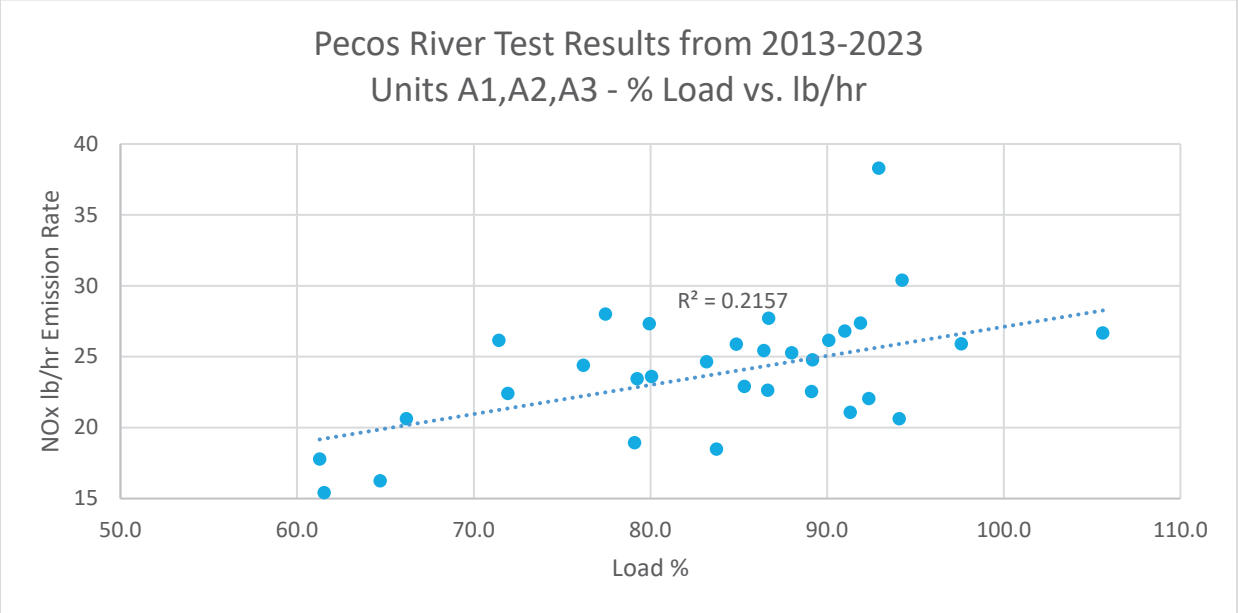
NMED followed substantially similar methodology for calculating emission factors at Pecos River Compressor Station as was done for Blanco A Compressor Station. Similarly, for the reasons stated in the Blanco A Compressor station response, EPNG disagrees with NMED's methodology. Additionally, for Pecos River Compression Station, EPNG notes:

1. The NOx emission rate for turbines does not increase linearly with load condition. As can be seen on the charts below, based on 10 years of emission test results, the observed R^2 is in the range of 0.22. A linear relationship would result in an R^2 value of 1. Thus, the existing correlation is considered insufficient to scale emission factors linearly with load; EPNG therefore recommends that the use of the inflated emission rate be discarded, as it is not representative of actual emissions.

2. While NMED used only the single most recent test data and EPNG believes that it is more appropriate to use the average test result over the 10-year period of 2013-2023, those two values are essentially the same and make no difference to the final results.

3. NMED used the ISO rating of the turbines to scale up the emission factors. For reasons stated above, EPNG believes that scaling emission factors is inappropriate. Additionally, NMED used the turbine's ISO rating expressed at sea level elevation, and 59 °F. Pecos River Compressor Station is located at an elevation of 2,900 feet and has much higher average daytime temperatures. Power generated by turbines decreases in warmer temperatures and higher elevations, due to less density and lower resulting mass of air flowing through the turbine. Based on GE power curves depicting this relationship, when fully loaded, the units will operate at a lower HP at the location than compared to the sea level ISO rating of 7,150. If emission factors are to be scaled, EPNG believes that the appropriate basis is the unit site rating of 5,650 HP.





B. SCR Efficiency

NMED cited an SCR efficiency rating of 90% in the calculations as "[C]onsistent with EPA and industry documentation". EPNG believes that not to be the case specifically for turbine driven natural gas transmission compression. The compressors at Pecos River Compressor station typically have an exhaust temperature of around 550F – 580F. Per the chart below from the June 2019 versions of the EPA Control Cost Manual, Section 4, Chapter 2 – Selective Catalytic

Reduction, Page 20[1], SCR efficiency in this temperature range is closer to 63%-73%. In EPNG's submittal we cited a 70% reduction efficiency as a conservative estimate.

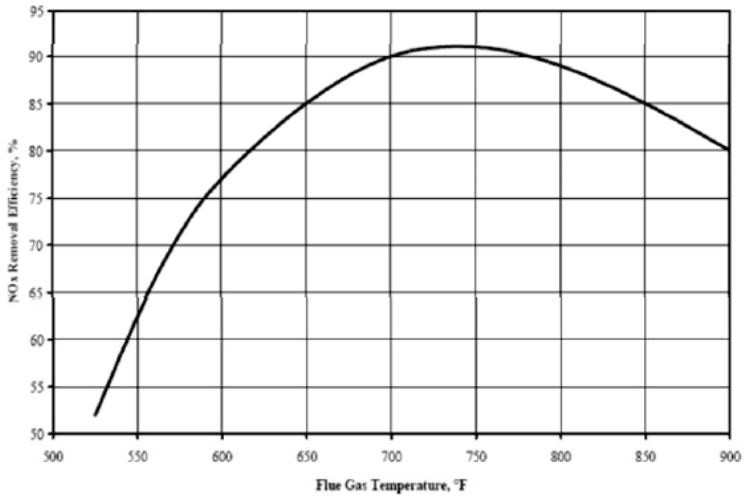


Figure 2.2: NO_x Removal versus Temperature [50]

C. Additional O&M Cost

EPNG submitted the O&M costs several years ago as part of its initial submissions. Considering the passage of time and the rate of inflation during that time, EPNG obtained up-to-date estimated costs for primary parts associated with the emission controls from the vendor. These updated O&M costs are also consistent with what EPNG submitted, and NMED relied on, for similar stations as part of the NM Ozone Rulemaking (20.2.50 NMAC). Accordingly, below, O&M costs are based on vendor quotes received in July of 2021 for reagent consumption, as well as maintenance, labor, electricity, and catalyst replacement costs.

Cost type	Unit A-01	Unit A-02	Unit A-03
Annual Maintenance	$35,905	$56,857	$56,857
Annual Operating Labor	$87,599	$87,600	$87,600
Annual Reagent	$90,114	$107,879	$95,762
Annual Electricity	$17,405	$20,836	$18,496
Annual Catalyst Replacement	$42,912	$51,371	$45,601
Direct Annual Cost	**$273,935**	**$324,543**	**$304,316**

These costs have been incorporated into the detailed calculations in Enclosure 2A.

D. Other Indirect Annual Cost - Administrative, Insurance, and Taxes

In NMED's draft final control cost evaluations spreadsheet, Other Indirect Annual Costs (OAC) are listed at $2,799 per unit. EPNG believes that costs should be slightly higher based on EPA

[1] https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf



recommended percentages of annual maintenance and operating costs. The appropriate costs are as follows:

Cost type	Unit A-01	Unit A-02	Unit A-03
Administrative Costs	$3,059	$3,310	$3,310

These costs have been incorporated into the detailed calculations in Enclosure 2A.

E. Capital Recovery Costs

In the part 20.2.50 NMAC 2021 rulemaking, EPNG provided vendor quotes for SCR modifications at a similar facility in New Mexico, which information was accepted and relied on by NMED. These same numbers are appropriate for use in the FFA for Pecos River Compressor Station. Based on these more up-to-date vendor quotes, and utilizing EPNG's documented, actual8.53% interest rate provided to NMED, total annual costs (including annualized capital recovery costs, direct annual costs, and administrative costs) are updated as follows:

Cost type	Unit A-01	Unit A-02	Unit A-03
Capital Recovery Costs	$760,473	$1,204,253	$1,204,253
Direct Annual Cost	$273,935	$324,543	$304,316
Administrative Costs	$3,059	$3,310	$3,310
Total Annual Cost (TAC)	**$1,037,467**	**$1,532,106**	**$1,511,879**

These costs have been incorporated into the detailed calculations in Enclosure 2A.

F. Pecos River Conclusion

Considering the above points 1 - 2, EPNG believes that the appropriate BAE for Pecos River Compressor Station should be based on NMED lb/hr rates cited in recent test results, which align with test averages for unit performance, as follows:

Unit	A-01	A-02	A-03
Average Hours (2016-2021)	3553	6378	5537
NOx (lb/hr)	22.4	25.3	24.4
BAE (ton/year)	39.8	80.7	67.5

Furthermore, considering the revised BAE numbers and all the information above, EPNG believes the final cost per ton for Pecos River Compressor Station is as follows:

Unit	A-01	A-02	A-03
NOx Control Efficiency (%)	70%	70%	70%
Estimated Reductions (ton/yr)	27.9	56.5	47.3
TAC ($/yr)	$1,037,467	$1,532,106	$1,511,879
2023$ Cost Effectiveness ($/ton)	**$37,248**	**$27,126**	**$31,976**

Detailed calculations are presented in Enclosure 2B.

IV. General Comments

EPNG wishes to clarify the appropriateness of various statements and considerations mentioned by NMED.

A. Electrification/Replacement

First, EPNG respectfully disagrees with NMED's consideration of replacement or electrification as an option for NOx emissions reductions. The Regional Haze Rule only requires analysis and application of *retrofit* technology (i.e., emissions control equipment) for existing engines. Neither replacement nor electrification is authorized by the Regional Haze provision or the implementing regulations, and units cannot be forced to undertake such a fundamental change to their facilities.

A fundamental principle of the Clean Air Act is that Congress did not intend to eliminate emissions sources; rather, Congress simply intended for *control* of emissions sources—*e.g.*, through scrubbers, capture devices, or other methods that reduce emissions of a pollutant without affecting the fundamental engineering design of the source. *See, e.g.*, *West Virginia v. EPA*, 142 S. Ct. 2587, 2612 n.3 (2022) (EPA may not "direct existing sources to effectively cease to exist" under 42 U.S.C. § 7411(d)); *Helping Hand Tools v. EPA*, 848 F.3d 1185, 1194 (9th Cir. 2016) (in determining "best available control technology" EPA may not "redefine the source" in a way that would disrupt the basic business purpose of the facility, which business purpose includes availability and use of on-site fuel). Congress took this approach in part to ensure that achieving clean air goals did not unnecessarily disrupt economic activity. *See Sierra Club v. Costle*, 657 F.2d 298, 331 (D.C. Cir. 1981) (noting legislative history of Clean Air Act showed Congress did not want to impede long term growth or inhibit technological innovation).

The Clean Air Act's regional haze provision is no different. For example, in the preamble to the 2017 Regional Haze Rule Amendment, EPA explained that "states must evaluate the control measures that are necessary to make reasonable progress using the four factors and develop their long-term strategies before they can predict future emissions reductions and conduct the regional-scale modeling used to establish [reasonable progress goals]." 82 Fed. Reg. 3,078, 3,090-91 (Jan. 10, 2017) (emphasis added). Thus, EPA only contemplates that "controls" should be used to meet reasonable progress goals. Controls are defined in other areas of the Clean Air Act as "application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant." 42 U.S.C. § 7479(3). This is further confirmed by the text of the relevant regulatory provision in the Regional Haze Rule, which refers to "installation" of a "control":

> In considering [one of the four statutory reasonable progress factors], if the State concludes that a *control measure cannot reasonably be installed* and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress.

40 C.F.R. § 51.308(f)(2)(i) (emphasis added). The discussion of *installing* a *control* suggests reference to an *existing* emissions unit that will remain in place and be modified, not the wholesale replacement of the emissions unit. This is basic logic: a control has to be installed on *something*. If an emissions unit is removed, then there is nothing on which to install the control.

EPA's 2019 guidance interpreting the 2017 Regional Haze Rule confirms and drives home EPA's intention that "control" will be used to achieve reasonable progress, and that replacement of existing sources with other technology is not included. EPA provided the following list of "control measures that states may consider":

1. Emission reductions through improved work practices.

2. Retrofits for sources with no existing controls.

3. Upgrades or replacements for existing, less effective controls.

4. Year-round operation of existing controls.

5. Fuel mix with inherently lower SO2, NOx, and/or PM emissions. States may also determine that it is unreasonable to consider some fuel-use changes because they would be too fundamental to the operation and design of a source.

6. Operating restrictions on hours, fuel input, or product output to reduce emissions.

7. Energy efficiency and renewable energy measures that could be applied elsewhere in a state to reduce emissions from EGUs.

8. Basic smoke management practices and smoke management programs for agricultural or wildland prescribed fires.

EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period 29-30 (Aug. 20, 2019) (footnote omitted). Self-evidently, none of these includes replacement or electrification. The only time "replacement" appears in this list is in reference to replacement of *controls*. Further, the use of "retrofit" for sources should not be interpreted as replacement or electrification. The best available *retrofit* technology in the Regional Haze Program has never been interpreted that way; rather, then plain text of "retrofit" means the *addition to* an existing emissions unit. *See* "retrofit" *Merriam Webster*. While this list is not exhaustive, it is certainly indicative of the types of controls EPA contemplated requiring – none of which compare to electrification or replacement.

More recent EPA guidance issued in 2021 also confirms this understanding. In that guidance, EPA clarifies that greater *efficiency of controls* could also be considered, and that guidance notably does not suggest replacement or electrification is appropriate. *See* EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period 7 (July 8, 2021) (discussing efficiency improvements of an "existing control" as a control measure to consider but not suggesting that replacement of the entire emissions unit is appropriate).

Finally, NMED's website pertaining to the Second Implementation Period never mentions replacement or electrification, but NMED does mention *control* multiple times: "*control*

technologies to reduce haze" and "the cost of *control*, time necessary to install *controls*…" NMED, Regional Haze Planning (emphases added). In sum, an evaluation of replacement and/or electrification of engines is outside the bounds of the Regional Haze Rule.

B. Operating Restrictions

These engines, and in fact, the entire fleet of ENPG's engines and turbines, are part of interstate natural gas pipelines that are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the federal Natural Gas Act. See, e.g., 18 C.F.R. §284.7(a) (setting forth requirements for interstate natural gas firm transportation service). FERC approves or "certificates" the pipeline to deliver natural gas. EPNG's pipeline system, as certificated by FERC, so that EPNG can move gas 24 hours a day, 365 days a year at its designed capacity. Reducing capacity of one or more of EPNG's engines or turbines through operating restrictions would require that EPNG seek and obtain approval from FERC. In certain circumstances, this might be viewed by FERC as abandonment of capacity and abandonment proceedings can take up to 11-13 months.

Additionally, as noted above, replacement of units, and by extension, retirement of existing units, is beyond the scope of the Regional Haze Rule. Accordingly, operating restrictions are not appropriate on EPNG's FERC-regulated engines and turbines.

Again, EPNG appreciates this opportunity to review and comment on the draft final control cost evaluations for the Regional Haze Second Planning Period in New Mexico. If you have any questions about our response, please contact Weiwen Daly by email at Weiwen_Daly@kindermorgan.com or by phone at 303-914-7616 or me by email at Tom_Mitchell@kindermorgan or by phone at 713-420-3463.

Sincerely,

R. Thomas Mitchell

Digitally signed by R. Thomas Mitchell
DN: cn=R. Thomas Mitchell, o=Kinder Morgan, ou, email=tom_mitchell@kindermorgan.com, c=US
Date: 2024.01.19 12:21:31 -06'00'

R. Thomas Mitchell
Manager, EHS

Enclosures

Enclosure 1

Blanco A Calculations

EPNG Blanco A Compressor Station Uncontrolled 2028 Emissions Projection

Unit No.	Operating Hours (hr/yr)									Projected 2028 Hours Based on (2016-2021) Average Hrs/yr	NOx EF (lb/hr) Based on the Average Test Data (2012-2023)	Notes	Projected 2028 NOx Emissions (tpy) based on Average Test Data (2012-2023) and Average Hours (2015-2022)
	2015	2016	2017	2018	2019	2020	2021	2022	Max				
A-1	2655.4	6728.5	5123.0	579.0	3787.0	2500	0	0	6728.50	3120	4.47		6.97
A-2	1.8	2.3	14.8	4.3	2199.0	5652	1.75	2669.75	2199.00	1312	7.52		4.93
A-3	5884.8	5012.8	5953.5	3182.0	5181.5	225	108	134.25	5953.50	3277	7.09		11.62
A-4	1.5	99.8	2.5	2.0	510.3	5055	7980	5243.5	510.25	2275	1.58		1.80
A-5	1.8	281.3	5.0	9.5	2.5	0	0.25	2.25	281.25	50	5.66		0.14
A-6	195.1	56.0	5567.3	2155.3	1.5	0	0.25	1817	5567.25	1297	6.43		4.17
A-7	8326.0	5964.5	6666.3	1371.0	3690.8	2547	1945.5	1371.25	8326.00	3698	6.57		12.15
A-8	2.0	1.8	1.3	1.3	1.5	0	0	0.25	2.00	1	7.24	A-8 last tested on 7/24/2012	0.00
A-9	367.3	2499.5	183.5	866.5	3141.0	2144	5006.5	4931.5	3141.00	2307	8.49		9.79
A-10	1.3	1.8	1.8	6.5	1.3	0	0.25	0	6.50	2	6.04	A-10 last tested on 7/24/2012	0.01
A-11	8413.6	4404.7	3239.5	7450.8	6580.3	7642	7075.75	4897.25	8413.59	6065	7.02		21.28
A-12	2.5	1.5	2.3	3560.5	2.3	0	217.5	0.25	3560.50	631	7.83		2.47
A-13	899.0	7490.8	6827.8	6108.8	7129.8	998	1033	720.75	7490.75	4931	5.99		14.76
A-14	2.0	1.8	1.3	7312.5	3259.0	0	0.25	0.25	7312.50	1762	1.57		1.38

Cost Analysis for Low Emission Controls for Engine A-1

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	3,120	3,120	3,120	Projection based on the average actual operating hours of 2015-2022
EQUIPMENT COST (EC)					
Cost per engine		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Pulsation Bottles		$0	$0	$900,000	
Total Cost per engine (TC)		$1,884,728	$2,975,000.29	$2,804,837.56	
Contingency Cost per unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Cost		$26,386,196	$41,650,004	$25,243,538	
Total Capital Investment per Unit (TCI)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		972	972	972	15% of operator
Parts & Repair Cost		$30,429	$30,429	$30,429	Vendor Estimate based on annual operating hours
Testing		$10,000	$10,000	$10,000	Annual Reference Method Test
Added Electricity Cost	5 kW/hr	$2,340	$2,340	$2,340	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$50,220**	**$50,220**	**$50,220**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [1]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$367,750**	**$542,730**	**$500,805**	
Baseline Actual NOx Emissions	tpy	6.97	6.97	6.97	Based on average test data (2012-2023) and average actual hours from 2015-2022
Post Control NOx Emissions	tpy	9.73	3.24	1.62	
Post Control NOx Concentration	g/hp-hr	3.0	1.0	0.5	
Estimated NOx Emissions Reduction	tpy	-2.76	3.73	5.35	
Cost Effectiveness	$/ton	**($133,295)**	**$145,642**	**$93,647**	

[1] Capital Recovery Factor :

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

Cost Analysis for Low Emission Controls for Engine A-2

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	1,312	1,312	1,312	Projection based on the average actual operating hours of 2015-2022
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Investment per Unit (TCI)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Parts & Repair Cost		$12,728	$12,728	$12,728	Vendor Estimate based on annual operating hours
Testing		$10,000	$10,000	$10,000	Annual Reference Method Test
Added Electricity Cost	5 kw/hr	$984	$984	$984	City of Farmington rate = $0.15/kWh
Total O&M Costs		**$31,164**	**$31,164**	**$31,164**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [1]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$348,694**	**$523,674**	**$481,749**	
Baseline Actual NOx Emissions	tpy	4.93	4.93	4.93	Based on average test data (2012-2023) and average actual hours from 2016-2021
Post Control NOx Emissions	tpy	4.09	1.36	0.68	
Post Control NOx Concentration	g/hp-hr	3.0	1.0	0.5	
Estimated NOx Emissions Reduction	tpy	0.84	3.57	4.25	
Cost Effectiveness	$/ton	**$414,120**	**$146,677**	**$113,291**	

[1] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

Cost Analysis for Low Emission Controls for Engine A-3

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	3,277	3,277	3,277	Projection based on the average actual operating hours of 2015-2022
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Constrution, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Pulsation Bottles		$0	$0	$900,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Investment per Unit (TCI)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Parts & Repair Cost		$32,067	$32,067	$32,067	Vendor Estimate based on annual operating hours
Testing		$10,000	$10,000	$10,000	Annual Reference Method Test
Added Electricity Cost	5 kW/hr	$2,458	$2,458	$2,458	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$51,977**	**$51,977**	**$51,977**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [1]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$369,506**	**$544,486**	**$502,561**	
Baseline Actual NOx Emissions	tpy	11.62	11.62	11.62	Based on average test data (2012-2023) and average actual hours from 2016-2021
Post Control NOx Emissions	tpy	10.22	3.41	1.70	
Post Control NOx Concentration	g/hp-hr	3.0	1.0	0.5	
Estimated NOx Emissions Reduction	tpy	1.40	8.21	9.91	
Cost Effectiveness	$/ton	**$264,298**	**$66,312**	**$50,691**	

[1] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

Cost Analysis for Low Emission Controls for Engine A-4

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	2,275	2,275	2,275	Projection based on the average actual operating hours of 2015-2022
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Investment per Unit (TCI)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required	hrs/day	$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Parts & Repair Cost		$22,065	$22,065	$22,065	Vendor Estimate based on annual operating hours
Testing		$10,000	$10,000	$10,000	Annual Reference Method Test
Added Electricity Cost	5 kW/hr	$1,706	$1,706	$1,706	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$41,223**	**$41,223**	**$41,223**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [1]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$358,753**	**$533,733**	**$491,808**	
Baseline Actual NOx Emissions	tpy	1.80	1.80	1.80	Based on average test data (2012-2023) and average actual hours from 2016-2021
Post Control NOx Emissions	tpy	7.09	2.36	1.18	
Post Control NOx Concentration	g/hp-hr	3.0	1.0	0.5	
Estimated NOx Emissions Reduction	tpy	-5.30	-0.57	0.61	
Cost Effectiveness	$/ton	**($67,729)**	**($940,489)**	**$799,896**	

[1] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

Cost Analysis for Low Emission Controls for Engine A-5

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	50	50	50	Projection based on the average actual operating hours of 2015-2022
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Pulsation Bottles		$0	$0	$900,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	from Good Neighbor cost estimate of similar unit
Total Capital Cost per Unit (TCC)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Parts & Repair Cost		$485	$485	$485	Vendor Estimate based on annual operating hours
Testing		$10,000	$10,000	$10,000	Annual Reference Method Test
Added Electricity Cost	5 kW/hr	$37	$37	$37	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$17,974**	**$17,974**	**$17,974**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [1]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$335,504**	**$510,484**	**$468,559**	
Baseline Actual NOx Emissions	tpy	0.14	0.14	0.14	Based on average test data (2012-2023) and average actual hours from 2016-2021
Post Control NOx Emissions	tpy	0.16	0.05	0.03	
Post Control NOx Concentration	g/hp-hr	3.0	1.0	0.5	
Estimated NOx Emissions Reduction	tpy	-0.01	0.09	0.11	
Cost Effectiveness	$/ton	**($23,384,597)**	**$5,730,671**	**$4,076,698**	

[1] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

Cost Analysis for Low Emission Controls for Engine A-6

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	1,297	1,297	1,297	Projection based on the average actual operating hours of 2015-2022
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles (14 units)		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Investment per Unit (TCI)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Parts & Repair Cost		$12,577	$12,577	$12,577	Vendor Estimate based on annual operating hours
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost	5 kW/hr	$973	$438	$438	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$31,002**	**$30,467**	**$30,467**	
Admin, insurance, taxes	4% of TCI	$87,053	$135,025	$123,531	
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [1]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$348,531**	**$522,977**	**$481,052**	
Baseline Actual NOx Emissions	tpy	4.17	4.17	4.17	Based on average test data (2012-2023) and average actual hours from 2016-2021
Post Control NOx Emissions	tpy	4.04	1.35	0.67	
Post Control NOx Concentration	g/hp-hr	3.0	1.0	0.5	
Estimated NOx Emissions Reduction	tpy	0.13	2.82	3.49	
Cost Effectiveness	$/ton	**$2,782,020**	**$185,385**	**$137,641**	

[1] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

Cost Analysis for Low Emission Controls for Engine A-7

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	3,698	3,698	3,698	Projection based on the average actual operating hours of 2015-2022
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles (14 units)		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit	10% of TC	$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Cost per Unit (TCC)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required (.5 hr/shift, similar to EPA example)		$6,480	$6,480	$6,480	
Supervisor labor		$972	$972	$972	15% of operator
Parts & Repair Cost		$35,925	$35,925	$35,925	Vendor Estimate based on annual operating hours
Testing		$10,000	$10,000	$10,000	Annual Reference Method Test
Added Electricity Cost	5 kW/hr	$2,773	$2,773	$2,773	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$56,150**	**$56,150**	**$56,150**	
Admin, insurance, taxes	4% of TCI	$87,053	$135,025	$123,531	
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [1]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$373,680**	**$548,660**	**$506,735**	
Baseline Actual NOx Emissions	tpy	12.15	12.15	12.15	Based on average test data (2012-2023) and average actual hours from 2016-2021
Post Control NOx Emissions	tpy	11.53	3.84	1.92	
Post Control NOx Concentration	g/hp-hr	3.0	1.0	0.5	
Estimated NOx Emissions Reduction	tpy	0.62	8.31	10.23	
Cost Effectiveness	$/ton	**$603,980**	**$66,060**	**$49,548**	

[1] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

Cost Analysis for Low Emission Controls for Engine A-8

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	1	1	1	Projection based on the average actual operating hours of 2015-2022
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$910,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Pulsation Bottles		$0	$0	$900,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit	10% of TC	$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Investment per Unit (TCI)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Parts & Repair Cost		$10	$10	$10	Vendor Estimate based on annual operating hours
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost	5 kW/hr	$1	$1	$1	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$17,463**	**$17,463**	**$17,463**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life		20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [1]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$334,992**	**$509,972**	**$468,047**	
Baseline Actual NOx Emissions	tpy	0.00	0.00	0.00	Based on average test data (2012-2023) and average actual hours from 2016-2021
Post Control NOx Emissions	tpy	0.00	0.00	0.00	
Post Control NOx Concentration	g/hp-hr	3.0	1.0	0.5	
Estimated NOx Emissions Reduction	tpy	0.00	0.00	0.00	
Cost Effectiveness	$/ton	**$696,865,144**	**$347,116,726**	**$189,556,768**	

[1] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

Cost Analysis for Low Emission Controls for Engine A-9

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	2,307	2,307	2,307	Projection based on the average actual operating hours of 2015-2022
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Investment per Unit (TCI)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Parts & Repair Cost		$22,402	$22,402	$22,402	Vendor Estimate based on annual operating hours
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost	5 kW/hr	$1,730	$1,730	$1,730	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$41,584**	**$41,584**	**$41,584**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [1]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$359,114**	**$534,094**	**$492,169**	
Baseline Actual NOx Emissions	tpy	9.79	9.79	9.79	Based on average test data (2012-2023) and average actual hours from 2016-2021
Post Control NOx Emissions	tpy	7.19	2.40	1.20	
Post Control NOx Concentration	g/hp-hr	3.0	1.0	0.5	
Estimated NOx Emissions Reduction	tpy	2.60	7.39	8.59	
Cost Effectiveness	$/ton	**$138,301**	**$72,250**	**$57,287**	

[1] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

Cost Analysis for Low Emission Controls for Engine A-10

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	2	2	2	Projection based on the average actual operating hours of 2015-2022
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	from Good Neighbor cost estimate of similar unit
Total Capital Cost per Unit (TCC)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Parts & Repair Cost		$16	$16	$16	Vendor Estimate based on annual operating hours
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost	5 kW/hr	$1	$1	$1	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$17,469**	**$17,469**	**$17,469**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [1]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$334,999**	**$509,979**	**$468,053**	
Baseline Actual NOx Emissions	tpy	0.01	0.01	0.01	Based on average test data (2012-2023) and average actual hours from 2016-2021
Post Control NOx Emissions	tpy	0.01	0.00	0.00	
Post Control NOx Concentration	g/hp-hr	3.0	1.0	0.5	
Estimated NOx Emissions Reduction	tpy	0.00	0.00	0.00	
Cost Effectiveness	$/ton	**($1,776,486,657)**	**$134,345,216**	**97,670,156**	

[1] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

Cost Analysis for Low Emission Controls for Engine A-11

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	6,065	6,065	6,065	Projection based on the average actual operating hours of 2015-2022
EQUIPMENT COST (EC)					
Cost per engine		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Cost per Unit (TCC)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Parts & Repair Cost		$58,978	$58,978	$58,978	Vendor Estimate based on annual operating hours
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost	5 kW/hr	$4,549	$4,549	$4,549	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$80,979**	**$80,979**	**$80,979**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [1]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$398,509**	**$573,489**	**$531,564**	
Baseline Actual NOx Emissions	tpy	21.28	21.28	21.28	Based on average test data (2012-2023) and average actual hours from 2016-2021
Post Control NOx Emissions	tpy	18.91	6.30	3.15	
Post Control NOx Concentration	g/hp-hr	3.0	1.0	0.5	
Estimated NOx Emissions Reduction	tpy	2.37	14.98	18.13	
Cost Effectiveness	$/ton	**$168,247**	**$38,288**	**$29,318**	

[1] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

Cost Analysis for Low Emission Controls for Engine A-12

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure fuel injection & turbocharger & compressor cylinder and power cylinder upgrade + engine uprate of 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	631	631	631	Projection based on the average actual operating hours of 2015-2022
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Cost per Unit (TCC)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Parts & Repair Cost		$6,121	$6,121	$6,121	Vendor Estimate based on annual operating hours
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost	5 kW/hr	$473	$473	$473	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$24,046**	**$24,046**	**$24,046**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [1]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$341,576**	**$516,556**	**$474,631**	
Baseline Actual NOx Emissions	tpy	2.47	2.47	2.47	Based on average test data (2012-2023) and average actual hours from 2016-2021
Post Control NOx Emissions	tpy	1.97	0.66	0.33	
Post Control NOx Concentration	g/hp-hr	3.0	1.0	0.5	
Estimated NOx Emissions Reduction	tpy	0.50	1.81	2.14	
Cost Effectiveness	$/ton	**$679,891**	**$284,838**	**$221,657**	

[1] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

Cost Analysis for Low Emission Controls for Engine A-13

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	4,931	4,931	4,931	Projection based on the average actual operating hours of 2015-2022
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissionsing, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	
Total Capital Cost pe Unit (TCC)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		$972	$972	$972	15% of operator
Parts & Repair Cost		$47,957	$47,957	$47,957	Vendor Estimate based on annual operating hours
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost		$3,699	$3,699	$3,699	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$69,108**	**$69,108**	**$69,108**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [1]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$386,637**	**$561,617**	**$519,692**	
Baseline Actual NOx Emissions	tpy	14.76	14.76	14.76	Based on average test data (2012-2023) and average actual hours from 2016-2021
Post Control NOx Emissions	tpy	15.38	5.13	2.56	
Post Control NOx Concentration	g/hp-hr	3.0	1.0	0.5	
Estimated NOx Emissions Reduction	tpy	-0.62	9.64	12.20	
Cost Effectiveness	$/ton	**($626,968)**	**$58,288**	**$42,604**	

[1] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

Cost Analysis for Low Emission Controls for Engine A-14

		High Pressure Electronic Fuel Injection (EFI) & electric blower & engine cooling system (LEC 1)	LEC1 + exhaust manifold replacement & Oxidation catalyst & cylinder heads with PCC (LEC2)	High Pressure EFI + turbocharger + compressor cylinder & power cylinder upgrade + uprate 9 units & retire 5 units (LEC3)	Reference
Engine Model		CB GMV10 - TF	CB GMV10 - TF	CB GMV10 - TF	
Engine Output	HP	943	943	943	
Hours of Operation Projection	hrs	1,762	1,762	1,762	Projection based on the average actual operating hours of 2015-2022
EQUIPMENT COST (EC)					
Cost per Unit		$784,014	$1,624,286	$1,334,282	Hoerbiger Budgetary Estimate from 9/20/2019
Off-Engine Fuel System		$500,000	$500,000	$500,000	
Automation Panels		$3,500,000	$3,500,000	$2,250,000	
New Ignition Sysytem		$910,000	$910,000	$585,000	
Pulsation Bottles		$0	$0	$900,000	
Construction, Inspection, Commissioning, Company Labor		$10,500,000	$14,000,000	$9,000,000	
Total Cost per Engine (TC)		$1,884,728	$2,975,000	$2,804,838	
Contingency Cost per Unit		$188,473	$297,500	$180,311	10% of TC
AFUDC (from GN cost analysis for GMVA-10)		$103,121	$103,121	$103,121	from Good Neighbor cost estimate of similar unit
Total Capital Cost per Unit (TCC)		**$2,176,322**	**$3,375,621**	**$3,088,270**	
ANNUAL COST					
Direct Operating Cost					
Operating Labor Required		$6,480	$6,480	$6,480	.5 hr/shift, similar to EPA example
Supervisor labor		972	972	972	15% of operator
Parts & Repair Cost		$17,094	$17,094	$17,094	Vendor Estimate based on annual operating hours
Testing (Annual Reference Method Test)		$10,000	$10,000	$10,000	
Added Electricity Cost	5 kW/hr	$1,322	$1,322	$1,322	City of Farmington rate = $ 0.15/kWh
Total O&M Costs		**$35,868**	**$35,868**	**$35,868**	
Admin, insurance, taxes		$87,053	$135,025	$123,531	4% of TCI
Equipment Life	yr	20	20	20	
Interest Rate		8.53%	8.53%	8.53%	EPNG cost of borrowing
Capital Recovery Factor [1]		0.1059	0.1059	0.1059	
Annualized Capital Recovery		$230,477	$357,485	$327,054	
Total Indirect Cost		**$317,530**	**$492,510**	**$450,585**	
Total Annualized Costs		**$353,397**	**$528,377**	**$486,452**	
Baseline Actual NOx Emissions	tpy	1.38	1.38	1.38	Based on average test data (2012-2023) and average actual hours from 2016-2021
Post Control NOx Emissions	tpy	5.50	1.83	0.92	
Post Control NOx Concentration	g/hp-hr	3.0	1.0	0.5	
Estimated NOx Emissions Reduction	tpy	-4.11	-0.45	0.47	
Cost Effectiveness	$/ton	**($85,933)**	**($1,178,155)**	**$1,040,483**	

[1] Capital Recovery Factor for the new Solar Mars turbine:

Interest Rate	8.53%
Remaining useful life of source	20
Capital Recovery Factor	0.1059

Enclosure 2A
Pecos River Cost Summary

Enclosure 2A - Cost Calculations
Pecos River Compressor Station

Alternative O&M Costs Recommended by EPNG:

Cost type	A-01	A-02	A-03	Notes
Annual Maintenance	$35,905	$56,857	$56,857	See Enclosure 2B
Annual Operating Labor	$87,599	$87,600	$87,600	See Enclosure 2B
Annual Regeant Cost	$90,114	$107,879	$95,762	See Enclosure 2B
Annual Electricity Cost	$17,405	$20,836	$18,496	See Enclosure 2B
Annual Catalyst Replacement Cost	$42,912	$51,371	$45,601	See Enclosure 2B
Direct Annual Cost	**$273,935**	**$324,543**	**$304,316**	

Other Indirect Administratvie Costs Recommended by EPNG:

Cost type	A-01	A-02	A-03	Notes
Administrative Cost	$3,059	$3,310	$3,310	0.03 * (Operator Cost + 0.4*Annual Maintenance Cost)

Capital Recovery Costs and TAC Recommended by EPNG:

Cost type	A-01	A-02	A-03	
Capital Recovery Costs	$760,473	$1,204,253	$1,204,253	Based on 8.53% inflation and SCR capital investment (see Enc. 2B)
Direct Annual Costs	$273,935	$324,543	$304,316	
Administrative Costs	$3,059	$3,310	$3,310	
Total Annual Cost (TAC)	**$1,037,467**	**$1,532,106**	**$1,511,879**	

Alternative BAE Calculation Recommended by EPNG:

Unit	A-01	A-02	A-03	
Average Hours (2016-2021)	3553	6378	5537	Same as NMED
NOx (lb/hr)	22.4	25.3	24.4	Same as NMED, based on recent tests and not extrapolated to 100% ISO load
BAE (ton/year)	39.8	80.7	67.5	

Alternative Cost Effectiveness Calculation Recommended by EPNG

Unit	A-01	A-02	A-03	
NOx Control Efficiency (%)	70%	70%	70%	Justified based on exhaust temperatures
Estimated Reductions (ton/yr)	27.9	56.5	47.3	
TAC ($/yr)	$1,037,467	$1,532,106	$1,511,879	
2023$ Cost Effectiveness ($/ton)	**$ 37,248**	**$ 27,126**	**$ 31,976**	

Enclosure 2B
Pecos River Cost Estimate

El Paso Natural Gas Company, LLC
Pecos River Station

GE Model M3712R Turbine	Interest Rate:	8.53%	<-- EPNG Interest Rate
A-01	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual

Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	7,180,921	<-- CE2107005 Caprock internal est 07/16/2021
Total Capital Investment	$	7,180,921	
Annualized TCI:	$	760,473	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	276,994	<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	1,037,468	

Unit A-01: Cost Estimate

Total Capital Investment (TCI) =	$ 7,180,921

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$273,935
Indirect Annual Costs (IDAC) =	$763,532
Total annual costs (TAC) = DAC + IDAC	$1,037,468

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$35,905	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	Per EPA Cost Manual Ch 2, 2.4.2 "operating and supervisory labor"
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$90,114	Vendor quote - $1.75/gal of aqueous ammonia delivered to site; Per ArieNox 7/08/21 quote, at 100% full load, ammonia consumption rate is approximately 10 gph, 2011-2020 average hours
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$17,405	Default rate of $0.0676/kWh used in the calculation
Annual Catalyst Replacement Cost =		$42,912	
Direct Annual Cost =		$273,935	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,059
Capital Recovery Costs (CR)=	CRF x TCI =	$760,473
Indirect Annual Cost (IDAC) =	AC + CR =	$763,532

Total Annual Cost (TAC) =	$1,037,468 Per Year

Unit A-01: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine?

What type of fuel does the unit burn?

Is the SCR for a new turbine or retrofit of an existing turbine?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty: 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?[1]: 61.8 MMBtu/hour

What is the higher heating value (HHV) of the fuel?[1,2]: 1,031 Btu/scf

What is the estimated actual annual fuel consumption?: 220,915,390 scf/Year (based on unit heat rating and 2016-2018 average horus)

Enter the net plant heat input rate (NPHR): 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 2900 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,941
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,690

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the Cost Estimate tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Fuel consumption adjusted for actual 2016 operating hours, per the 2016 Emission Inventory submittal (524.9 MMscf/yr * 4982.50/8760 hours/year = 298.55 MMscf/yr)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR}): 365 days

Number of days the turbine operates (tplant): 365 days

Inlet NO_x Emissions (NOx_{in}) to SCR[2]: 0.2751 lb/MMBtu (2016-2018 avg. test results)

Outlet NO_x Emissions (NOx_{out}) from SCR[2]: 0.0825 lb/MMBtu

Stoichiometric Ratio Factor (SRF): 1.050

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst ($H_{catalyst}$): 24,000 hours

Estimated SCR equipment life: 20 Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored}): 29 percent*

Density of reagent as stored (ρ_{stored}): 56 lb/cubic feet*

Number of days reagent is stored ($t_{storage}$): 14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Select the reagent used

Number of SCR reactor chambers (n_{scr}): 1

Number of catalyst layers (R_{layer}): 3

Number of empty catalyst layers (R_{empty}): 1

Ammonia Slip (Slip) provided by vendor: 2 ppm

Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known): UNK Cubic feet

Flue gas flow rate ($Q_{bulkgas}$) (Enter "UNK" if value is not known): UNK acfm

Gas temperature at the SCR inlet (T): 650 °F

Base case fuel gas volumetric flow rate factor (Q_{act})[4]: 25975.21 ft^3/min-MMBtu/hour

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Permitted NO_x emission rate / permitted heat input (53.1 lb/hr / 61.8 Mmbtu/hr)

[3] Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032; 70% efficiency

[4] Calculated based on the estimated actual annual fuel consumption and maximum heat input rate.

Enter the cost data for the proposed SCR:

Desired dollar-year: 2018

CEPCI for 2018: 603.1 Enter the CEPCI value for 2018 (541.7 2016 CEPCI)

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i): 5.5 Percent*

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

Reagent ($Cost_{reag}$): 0.293 $/gallon for 29% ammonia*

* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.

Electricity ($Cost_{elect}$): 0.0676 $/kWh

* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.

Catalyst cost ($CC_{replace}$): 227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

Operator Labor Rate: 60.00 $/hour (including benefits)*

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

Operator Hours/Day: 4.00 hours/day*

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) = 0.005

Administrative Charges Factor (ACF) = 0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution [a]ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

Unit A-01: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	61.8	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	525,090,204	scf/Year (based on unit heat rating and 2016-2018 average horus)	
Actual Annual fuel consumption (Mactual) =		220,915,390	scf/Year (based on unit heat rating and 2016-2018 average horus)	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.421	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3685	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	11.90	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	21.93	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.88		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	1,536,075	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	7,082.81	/hour	
Residence Time	1/V_{space}	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.11		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia	
Retrofit Factor (RF)	Retrofit to existing turbine	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1), where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	216.87	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	1,600	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	1,840	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	42.9	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	5	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	16	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	800	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	31.78	kW

El Paso Natural Gas Company, LLC
Pecos River Station

GE Model M3712R Turbine	Interest Rate:	8.53%	EPNG Interest Rate
A-02	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual

Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	11,371,394	<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP)
Total Capital Investment	$	11,371,394	
Annualized TCI:	$	1,204,253	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	327,853	<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	1,532,106	

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$324,543
Indirect Annual Costs (IDAC) =	$1,207,563
Total annual costs (TAC) = DAC + IDAC	$1,532,106

Direct Annual Costs (DAC)
DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$56,857	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	Per EPA Cost Manual Ch 2, 2.4.2 "operating and supervisory labor"
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$107,879	Vendor quote - $1.75/gal of aqueous ammonia delivered to site; Per ArieNox 7/08/21 quote, at 100% full load, ammonia consumption rate is approximately 10 gph, 2011-2020 average hours
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$20,836	Default rate of $0.0676/kWh used in the calculation
Annual Catalyst Replacement Cost =		$51,371	
Direct Annual Cost =		$324,543	

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,310
Capital Recovery Costs (CR)=	CRF x TCI =	$1,204,253
Indirect Annual Cost (IDAC) =	AC + CR =	$1,207,563

Total Annual Cost (TAC) =	$1,532,106 Per Year

Unit A-02: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine?

What type of fuel does the unit burn?

Is the SCR for a new turbine or retrofit of an existing turbine?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?[1] 61.8 MMBtu/hour

What is the higher heating value (HHV) of the fuel?[1,2] 1,031 Btu/scf

What is the estimated actual annual fuel consumption? 377,406,695 scf/Year (based on unit heat rating and 2016-2018 average horus)

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 2900 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,341
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,690

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the Cost Estimate tab. Please select your preferred method:

Method 1
Method 2
Not applicable

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.
[2] Fuel consumption adjusted for actual 2016 operating hours, per the 2016 Emission Inventory submittal (524.9 MMscf/yr * 7165.5/8760 hours/year = 429.3 MMscf/yr)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR}) 365 days

Number of days the turbine operates (tplant) 365 days

Inlet NO_x Emissions (NOx_{in}) to SCR[2] 0.4249 lb/MMBtu

Outlet NO_x Emissions (NOx_{out}) from SCR[2] 0.1275 lb/MMBtu

Stoichiometric Ratio Factor (SRF) 1.050

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr}) 1

Number of catalyst layers (R_{layer}) 3

Number of empty catalyst layers (R_{empty}) 1

Ammonia Slip (Slip) provided by vendor 2 ppm

Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known) UNK Cubic feet

Flue gas flow rate ($Q_{bluegas}$) (Enter "UNK" if value is not known) UNK acfm

Estimated operating life of the catalyst ($H_{catalyst}$) 24,000 hours

Estimated SCR equipment life 20 Years*
* For industrial turbines, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T) 650 °F *The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Base case fuel gas volumetric flow rate factor (Q_{act})[4] 44375.44 ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored}) 29 percent*

Density of reagent as stored (ρ_{stored}) 56 lb/cubic feet*

Number of days reagent is stored ($t_{storage}$) 14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.
[2] Permitted NO_x emission rate / permitted heat input (53.1 lb/hr / 61.8 Mmbtu/hr)
[3] Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032; 70% efficiency
[4] Calculated based on the estimated actual annual fuel consumption and maximum heat input rate.

Enter the cost data for the proposed SCR:

Desired dollar-year 2018

CEPCI for 2018 603.1 Enter the CEPCI value for 2018 541.7 2016 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i) 5.5 Percent* * 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

Reagent ($Cost_{reag}$) 0.293 $/gallon for 29% ammonia* * $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.

Electricity ($Cost_{elect}$) 0.0676 $/kWh * $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.

Catalyst cost ($CC_{replace}$) 227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst * $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

Operator Labor Rate 60.00 $/hour (including benefits)* * $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

Operator Hours/Day 4.00 hours/day* * 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) = 0.005

Administrative Charges Factor (ACF) = 0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution [a]ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit A-02: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	62	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	525,090,204	scf/Year (based on unit heat rating and 2016-2018 average horus)	
Actual Annual fuel consumption (Mactual) =		377,406,695	scf/Year (based on unit heat rating and 2016-2018 average horus)	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.719	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6296	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	18.38	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	57.87	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.88		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,624,195	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	11,511.83	/hour	
Residence Time	1/V_{space}	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.11		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia	
Retrofit Factor (RF)	Retrofit to existing turbine	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1), where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	227.96	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,734	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	3,144	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	56.1	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	7	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	25	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,200	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	31.78	kW

El Paso Natural Gas Company, LLC
Pecos River Station

GE Model M3712R Turbine	Interest Rate:	8.53%	EPNG Interest Rate
A-03	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual

Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	11,371,394	<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP)
Total Capital Investment	$	11,371,394	
Annualized TCI:	$	1,204,253	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	307,626	<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	1,511,879	

Unit A-03: Cost Estimate

Total Capital Investment (TCI) =	$ 11,371,394

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$304,316
Indirect Annual Costs (IDAC) =	$1,207,563
Total annual costs (TAC) = DAC + IDAC	$1,511,879

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$56,857	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	Per EPA Cost Manual Ch 2, 2.4.2 "operating and supervisory labor"
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$95,762	Vendor quote - $1.75/gal of aqueous ammonia delivered to site; Per ArieNox 7/08/21 quote, at 100% full load, ammonia consumption rate is approximately 10 gph, 2011-2020 average hours
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$18,496	Default rate of $0.0676/kWh used in the calculation
Annual Catalyst Replacement Cost =		$45,601	
Direct Annual Cost =		$304,316	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,310
Capital Recovery Costs (CR)=	CRF x TCI =	$1,204,253
Indirect Annual Cost (IDAC) =	AC + CR =	$1,207,563

Total Annual Cost (TAC) =	$1,511,879	Per Year

Unit A-03: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine?

What type of fuel does the unit burn?

Is the SCR for a new turbine or retrofit of an existing turbine?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty: 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?[1]: 61.8 MMBtu/hour

What is the higher heating value (HHV) of the fuel?[1,2]: 1,031 Btu/scf

What is the estimated actual annual fuel consumption?: 384,017,879 scf/Year (based on unit heat rating and 2016-2018 average horus)

Enter the net plant heat input rate (NPHR): 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 2900 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,941
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,690

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the Cost Estimate tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Fuel consumption adjusted for actual 2016 operating hours, per the 2016 Emission Inventory submittal (524.9 MMscf/yr * 6501.75/8760 hours/year = 389.6 MMscf/yr)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR}): 365 days

Number of days the turbine operates (tplant): 365 days

Inlet NO_x Emissions (NOx_{in}) to SCR[2]: 0.3973 lb/MMBtu

Outlet NO_x Emissions (NOx_{out}) from SCR[2]: 0.1192 lb/MMBtu

Stoichiometric Ratio Factor (SRF): 1.050

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr}): 1

Number of catalyst layers (R_{layer}): 3

Number of empty catalyst layers (R_{empty}): 1

Ammonia Slip (Slip) provided by vendor: 2 ppm

Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known): UNK Cubic feet

Flue gas flow rate ($Q_{bulkgas}$) (Enter "UNK" if value is not known): UNK acfm

Estimated operating life of the catalyst ($H_{catalyst}$): 24,000 hours

Estimated SCR equipment life: 20 Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T): 650 °F

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual temperature, if known.

Base case fuel gas volumetric flow rate factor (Q_{bef})[4]: 45152.79 ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored}): 29 percent*

Density of reagent as stored (ρ_{stored}): 56 lb/cubic feet*

Number of days reagent is stored ($t_{storage}$): 14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.

[2] Permitted NO_x emission rate / permitted heat input (53.1 lb/hr / 61.8 Mmbtu/hr)

[3] Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032; 70% efficiency

[4] Calculated based on the estimated actual annual fuel consumption and maximum heat input rate.

Enter the cost data for the proposed SCR:

Desired dollar-year: 2018

CEPCI for 2018: 603.1 Enter the CEPCI value for 2018 (541.7 2016 CEPCI)

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i): 5.5 Percent*

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

Reagent ($Cost_{reag}$): 0.293 $/gallon for 29% ammonia*

* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.

Electricity ($Cost_{elect}$): 0.0676 $/kWh

* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.

Catalyst cost ($CC_{replace}$): 227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

Operator Labor Rate: 60.00 $/hour (including benefits)*

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

Operator Hours/Day: 4.00 hours/day*

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) = 0.005

Administrative Charges Factor (ACF) = 0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution [a]ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Unit A-03: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	62	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	525,090,204	scf/Year (based on unit heat rating and 2016-2018 average horus)	
Actual Annual fuel consumption (Mactual) =		384,017,879	scf/Year (based on unit heat rating and 2016-2018 average horus)	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.731	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6407	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	17.19	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	55.06	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.88		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,670,165	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	11,819.40	/hour	
Residence Time	1/V_{space}	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.11		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia	
Retrofit Factor (RF)	Retrofit to existing turbine	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1), where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	225.91	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,781	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	3,199	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	56.6	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	7	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	23	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,100	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	31.78	kW

El Paso Natural Gas Company, LLC - Pecos River Compressor Station

Turbines

Units: **A-01, A-02, A-03**
Description: **GE Regenerative Cycle Turbines (model M3712R)**

ISO Rating: **7150** **hp**
Fuel Heating Value: **1031** **Btu/scf**

	A-01	A-02	A-03
2016 through 2018 Average Operating Hours:	3,686.83	6,298.50	6,408.83

Criteria Pollutant	Emission Factor A-01	Emission Factor A-02	Emission Factor A-03	Units	Source	A-01 TPY	A-02 TPY	A-03 TPY
NOx	17.00	26.26	24.55	lb/hr	2016 through 2018 average stack test results	31.338	82.699	78.679

Op Hour Comparison

Operating Hours Per Year			
Yr/Unit	A-01	A-02	A-03
2014	6,920.92	5,983.92	7126.67
2015	5,602.33	4,018.83	5585.25
2016	4,982.50	7,165.50	6501.75
2017	754.75	7,916.25	7693.25
2018	5,323.25	3,813.75	5,031.50
2016 – 2018 Avg. Hours	**3,686.83**	**6,298.50**	**6,408.83**

Op Hour Comparison

Operating Hours Per Year			
Yr/Unit	A-01	A-02	A-03
2011	7,346.33	4,309.33	2591.08
2012	8,358.00	7,051.17	3727.58
2013	4,767.33	7,303.67	6774.59
2014	6,920.92	5,983.92	7126.67
2015	5,602.30	4,018.80	5585.25
2016	4,982.50	7,165.50	6501.75
2017	754.75	7,916.25	7693.25
2018	5,323.25	3,813.75	5031.5
2019	2,700.75	6,738.75	5356.25
2020	4,737.75	7,344.00	4333.25
2011 – 2020 Avg. Hours	**5,149.39**	**6,164.51**	**5,472.12**

ATTACHMENT 2

Blanco A Cost Support (Sept. 5, 2024)

KINDER MORGAN

PROJECT NAME			
COMPANY NAME	El Paso Natural Gas Company	**COMPANY NO.**	5205
REQUESTED BY		**PREPARED BY**	-
ESTIMATE NO.	CE100	**ORIGINAL EST. DATE**	09/05/24
REVISION NO.	-	**CONSTRUCTION CONTINGENCY**	10%
REVISION DATE		**OVERHEAD**	9.2%
PROJECT MANAGER		**AFUDC RATE (Debt / Equity)**	0.00% / 0.00%
STATE	New Mexico	**TAX GROSS UP**	0.00%
COUNTY		**PROJECT TYPE**	O&M / Integrity
		IN-SERVICE	Feb-26
		ESTIMATE ACCURACY LEVEL	Class 5

CAT G3606 A4 - Ariel Package SCOPE:	CAT G3606, 1,875 HP. 24" Headers
0 SCOPE:	Add an additional CAT G3608, 2,500 HP to existing site.
0 SCOPE:	Add an additional CAT G3608, 2,500 HP to existing site.
0 SCOPE:	Add an additional CAT G3606, 1,875 HP to existing site.
0 SCOPE:	Add an additional CAT G3606, 1,875 HP to existing site.

HP Rating =	**1,875**	**0**	**0**	**0**	**0**	
Cost Per HP (Direct + Contingency) =	**$7,148**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	

ESTIMATE SUMMARY

	CAT G3606 A4 - Ariel Package	-	-	-	-	TOTAL
MATERIAL (INCL SALES TAX)	$ 6,983,400	$ -	$ -	$ -	$ -	$ 6,983,400
COMPANY LABOR COST	$ -	$ -	$ -	$ -	$ -	$ -
PM, ENG, LAND, ENVIRO - EXPENSE	$ 2,500	$ -	$ -	$ -	$ -	$ 2,500
PRIMARY CONSTRUCTION CONTRACTOR	$ 4,250,300	$ -	$ -	$ -	$ -	$ 4,250,300
SECONDARY CONTRACTOR	$ 21,400	$ -	$ -	$ -	$ -	$ 21,400
PROFESSIONAL ENGINEERING	$ 300,300	$ -	$ -	$ -	$ -	$ 300,300
INSPECTION SERVICES	$ 422,300	$ -	$ -	$ -	$ -	$ 422,300
RADIOGRAPHY SERVICES	$ 44,100	$ -	$ -	$ -	$ -	$ 44,100
ENVIRONMENTAL CONTRACTOR	$ 49,300	$ -	$ -	$ -	$ -	$ 49,300
ELECTRICAL & INSTRUMENTATION	$ -	$ -	$ -	$ -	$ -	$ -
RIGHT OF WAY CONTRACTOR	$ 11,500	$ -	$ -	$ -	$ -	$ 11,500
SURVEY CONTRACTOR	$ 38,500	$ -	$ -	$ -	$ -	$ 38,500
OUTSIDE LEGAL SERVICES	$ 25,700	$ -	$ -	$ -	$ -	$ 25,700
ROW & DAMAGES	$ 19,800	$ -	$ -	$ -	$ -	$ 19,800
PERMIT FEES	$ -	$ -	$ -	$ -	$ -	$ -
GAS LOSS	$ 15,600	$ -	$ -	$ -	$ -	$ 15,600
SUBTOTAL	$ 12,184,700	$ -	$ -	$ -	$ -	$ 12,184,700
CONSTRUCTION CONTINGENCY	$ 1,218,470	$ -	$ -	$ -	$ -	$ 1,218,470
AFUDC	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ 13,403,170	$ -	$ -	$ -	$ -	$ 13,403,170
CAPITALIZED OVERHEAD (BURDEN)	$ 1,285,793	$ -	$ -	$ -	$ -	$ 1,285,793
TAX GROSS-UP	$ -	$ -	$ -	$ -	$ -	$ -
ESCALATION	$ 640,592	$ -	$ -	$ -	$ -	$ 640,592
						$ -
ESTIMATED TOTAL COST	**$ 15,329,555**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 15,329,555**
Price/Ton:						
(If Applicable) Escalated Price/Ton:						
Contingency:	10%	10%	10%	10%	10%	
In-Service Date:	Feb-26	Feb-26	Feb-26	Feb-26	Feb-26	

ASSUMPTIONS

Include (Yes/No)	Assumptions	
Yes	See Assumptions Tab	

Revision	Date	Notes	Approval	Name	Date
			Project Manager		
			Project Manager Director		
			Project Controls		
			Vice President		

AUTHORITY LEVELS:
< $25,000,000 PM, PM Director, Project Controls
> $25,000,000 PM, PM Director, Project Controls, VP

Escalation Rates $FV=PV(1+i)^n$	
Material:	2.0%
Other:	2.0%

Estimate Form Revision 8.3 (Draft) 04/05/16

ATTACHMENT 3

SCR Reagent Vendor Quote (August 2021)

[redacted]
Date: Thursday, August 19, 2021 3:27:21 PM

[This email message was received from the Internet and came from outside of Kinder Morgan.]

WARNING: EXTERNAL EMAIL: PROCEED WITH CAUTION.

Do not respond, click on links or open attachments unless you recognize the sender or know the content is safe.

No, it would be roughly 6,000/gal per truckload.

[redacted]

-----Original Message-----
[redacted]
Sent: Thursday, August 19, 2021 3:16 PM
[redacted]

CAUTION: EXTERNAL EMAIL - Do not click links or open attachments unless you recognize the sender and know the content is safe.

A load would be the entire 30000 gallons?

[redacted]

-----Original Message-----
[redacted]
Received: Thursday, 19 Aug 2021, 4:13PM
[redacted]

[This email message was received from the Internet and came from outside of Kinder Morgan.]

WARNING: EXTERNAL EMAIL: PROCEED WITH CAUTION.

Do not respond, click on links or open attachments unless you recognize the sender or know the content is safe.
Hey James,

So for budgetary purposes the price on this material is going to run $1.35/gal plus freight, which at this time is running about $2,700 per load.

[redacted]

[redacted]
Sent: Tuesday, August 17, 2021 10:45 AM
[redacted]

CAUTION: EXTERNAL EMAIL - Do not click links or open attachments unless you recognize the sender and know the content is safe.

If at all possible I need some type of estimate by the end of the week because the state Arizona wants our feedback by Monday the 23rd. If it is something you don't think you can have by then let me know and I will see if I can find someone else that might have the information. I apologize for the rush but the state just told us they wanted our feedback by that date.

Thank you,

[redacted]

[redacted]
Sent: Tuesday, August 17, 2021 11:09 AM
[redacted]

[This email message was received from the Internet and came from outside of Kinder Morgan.]

WARNING: EXTERNAL EMAIL: PROCEED WITH CAUTION.

Do not respond, click on links or open attachments unless you recognize the sender or know the content is safe.
Hi James,

I am still waiting to hear back from the product manager on the pricing. As soon as I get it, Ill shoot it over to you.

[redacted]

Sent: Tuesday, August 17, 2021 9:05 AM
[redacted]

CAUTION: EXTERNAL EMAIL - Do not click links or open attachments unless you recognize the sender and know the content is safe.

I was wondering if you think you will have something ready by the end of the week?

Thanks,

[redacted]

Sent: Thursday, August 12, 2021 6:35 PM
[redacted]

[This email message was received from the Internet and came from outside of Kinder Morgan.]

WARNING: EXTERNAL EMAIL: PROCEED WITH CAUTION.

Do not respond, click on links or open attachments unless you recognize the sender or know the content is safe.
Hello James,

It was good to speak with you today, I really appreciate you taking the time! As soon as I have pricing on the aqueous ammonia, Ill send it over to you. Would you happen to know if the Kinder Morgan locations here in the Bloomfield, NM area are looking at doing the same thing?

[redacted]

[A picture containing drawingDescription automatically generated]

ATTACHMENT 4

Letter from Cindy Hollenberg, AQB Compliance and Enforcement Section Chief, to Weiwen Daly, Kinder Morgan, Inc., Conditionally Approving AES (June 26, 2023)

June 26, 2023

Weiwen Daly
Kinder Morgan
1657 Cole Blvd., Suite 300
Lakewood, Colorado 80401
Weiwen_Daly@kindermorgan.com

Via electronic mail

Re: Alternative Emission Standards Proposal for El Paso Natural Gas – Conditional Approval

Dear Weiwen Daly,

Pursuant to 20.2.50.113.B(11) NMAC, Kinder Morgan submitted on December 2, 2022 to New Mexico Environment Department (Department), Air Quality Bureau (AQB or Bureau) a request to approve an Alternative Emission Standard (AES) for ten GE Gas Turbines for El Paso Natural Gas Company, L.L.C. (EPNG). The request included alternative reductions for nitrogen oxides (NOx) due to economic infeasibility for retrofit emissions control technologies deemed technically feasible. The submitted proposal included an independent third party certification of the evaluation.

On December 20, 2022, the Bureau requested further information, including a demonstration that the standards could not be met through an Alternative Compliance Plan and conversion of units to those found in 20.2.50.113 NMAC. This information was supplied to the Bureau on April 24, 2023.

On May 3, 2023, the Bureau notified Kinder Morgan that the complete proposal had been posted to the Department web site and would be available on the public comment portal for 30 days. This notice also included instructions for publishing “in a newspaper of general circulation.” Proof of publication in 4 county newspapers was submitted to the Bureau on May 15, 2023.

No public comments were received. However, the Bureau requested further clarification regarding ongoing costs on June 20, 2023. Kinder Morgan responded on June 21, 2023.

With the completion of all required documentation, notification and clarification, the Department hereby conditionally approves the AES proposal for the ten GE turbines referenced in the proposal. The approval is conditional only to the extent that, when any turbine is permanently replaced, the replacement turbine shall be considered “new” pursuant to the rule and must comply with the emissions standards in Table 3. However, short-term replacements and reinstallation of the existing turbines do not affect the status and will still be considered existing; they will remain covered under this Alternative Emission Standard.

Please note that the emissions reductions and alternative standards for the affected turbines are considered enforceable under this rule (20.2.50 NMAC). Please work with Permitting to determine what actions, if any, are necessary to memorialize the emission limits in permits.

ATTACHMENT 5

Barr, New Mexico Alternative Emission Standards Proposal
(Rev. April 2023)

New Mexico Alternative Emission Standards Proposal

Prepared for
El Paso Natural Gas Company, LLC

November 2022

Revision April 2023

225 E 16th Ave, Denver, CO 80203
Floor 5, suite 500
800.632-2277
www.barr.com

New Mexico Alternative Emission Standards Proposal

April 2023

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Appendix A-3 Letter from Baker Hughes Dated October 16, 2019

1 Executive Summary

The New Mexico Environmental Department (NMED) proposed and the New Mexico Environmental Improvement Board (EIB) finalized the Ozone Precursor rule under 20.2.50 NMAC to reduce ozone emissions at sources causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone. In lieu of meeting the emission standards established under 20.2.50.113 for portable and stationary natural gas-fired combustion engines or turbines, owners and operators may submit a request for alternative emission standards for a specific engine or turbine based on technical impracticability or economic infeasibility. El Paso Natural Gas Company, L.L.C. (EPNG)., a subsidiary of Kinder Morgan, Inc. (Kinder Morgan), requests alternative emission standards for ten (10) GE stationary natural gas-fired combustion turbines on the basis of economic infeasibility.

EPNG conducted a technical and economic analysis of emission controls for the 10 GE stationary natural gas-fired combustion turbines to reduce NO_X emissions. The only technically practicable technology for each turbine is Selective Catalytic Reduction (SCR). In general, NMED considers costs in excess of $7,500/ton of pollutant reduced to be economically infeasible. As noted in Kinder Morgan's Technical Testimony filed on July 28, 2021, and further documented in this submission, the cost per ton of installing SCR on these 10 GE turbines ranges up to $458,302 based on actual historical operating hours. Even in the most conservative case, based on Potential to Emit (PTE), installing SCR on these 10 GE turbines is not economically feasible. A review of potential control technologies and cost analyses are presented in Sections 3 and 4. The economic infeasibility of SCR installation is summarized below in Table 1-1. EPNG has concluded that alternative emission standards (AES) for NOx for the 10 GE gas turbines are warranted because the cost of compliance for technically practicable retrofit emission control technologies is not economically feasible, and the units' NOx emissions cannot be addressed through an Alternate Compliance Plan (ACP).

Table 1-1 Summary of Cost Effectiveness Evaluation

Turbine Location	Unit No.	Permitted Turbine Rating (hp)	Cost Effectiveness ($/ton NOx Removed) Based on Actual Emissions*	Cost Effectiveness ($/ton NO_X Removed) Based on PTE
Afton	A-01	6,150	$123,236	$11,697
Afton	A-02	6,150	$458,302	$11,097
Afton	A-03	6,150	$48,516	$11,097
Belen	A-01	4,737	$88,704	$30,794
Belen	A-02	4,737	$60,982	$29,214
Caprock	A-01	6,026	$80,398	$9,933
Caprock	A-02	4,879	$54,935	$29,283
Pecos River	A-01	7,150	$27,877	$8,261
Pecos River	A-02	7,150	$22,517	$11,097
Pecos River	A-03	7,150	$26,527	$11,097

*The data in the second-to-last column are from Kinder Morgan's Technical Testimony filed on July 28, 2021 before the EIB in which KM used the average actual emissions from 2018 to 2020. This data was ultimately relied upon by the EIB in support of adoption of Paragraphs (10) and (11) of Subsection B of 20.2.50.113 NMAC, which are the options to comply with the emissions limits through an AES or ACP. See State of New Mexico, Environmental Improvement Board, Statement of Reasons and Final Order, In the Matter of Proposed New Regulation 20.2.50 NMAC – Oil and Gas Sector – Ozone Precursor Pollutants, No. EIB 21-27, at pp. 100-101 (June 27, 2022) (hereinafter, Statement of Reasons). The last column shows cost-ineffectiveness calculations based on the more conservative PTE scenario. Even if the Department considers the overly conservative approach of using PTE to estimate the cost-per-ton, installation of SCR remains economically infeasible. See Section 4, Cost Analysis, for additional discussion regarding the economic infeasibility evaluation.

2 Introduction

The regulatory background and turbine information are summarized below.

2.1 Regulatory Background

The New Mexico EIB finalized the Ozone Precursor rule under 20.2.50 NMAC to reduce ozone emissions at existing and new sources causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone. Sources located in Chaves, Dona Ana, Eddy, Lea, Rio Arriba, Sandoval, San Juan, and Valencia counties are subject to the rule.

EPNG owns and operates 10 existing GE stationary natural gas-fired combustion turbines with a maximum design rating equal to or greater than 1,000 hp, as summarized in Table 2-1. These 10 GE turbines are included in this AES proposal.

Table 2-1 EPNG Sources Included in The AES

Engine Location	Unit No.	Turbine Manufacturer	Turbine Model	Hourly NOx Permit Limit	Annual NOx Permit Limit
Afton	A-01	GE	MS3712R-A	51.3 pph	224.5 tpy
Afton	A-02	GE	MS3712R-A	51.3 pph	224.5 tpy
Afton	A-03	GE	MS3712R-A	51.3 pph	224.5 tpy
Belen	A-01	GE	MS3572R-C	38.6 pph	169.0 tpy
Belen	A-02	GE	MS3572R-C	38.6 pph	169.0 tpy
Caprock	A-01	GE	MS3702R-C	45.9 pph	201.0 tpy
Caprock	A-02	GE	MS3572R-C	39.3 pph	172.1 tpy
Pecos River	A-01	GE	MS3712R-A	51.3 pph	232.6 tpy
Pecos River	A-02	GE	MS3712R-A	51.3 pph	232.6 tpy
Pecos River	A-03	GE	MS3712R-A	51.3 pph	232.6 tpy
Total					2,082.4 tpy

The Ozone Precursor Rule, at 20.2.50.113.B(11) NMAC states that "the owner or operator may submit a request for alternative emission standards for a specific engine or turbine based on technical impracticability or economic infeasibility." The rule further states that "[t]he owner or operator is not required to submit an ACP proposal under Paragraph (10) of Subsection B of 20.2.50.113 NMAC prior to submission of a request for alternative emission standards under this Paragraph (11), provided that the owner or operator satisfies Subparagraph (b) of Paragraph (11) of Subsection B of 20.2.50.113 NMAC, below." See 20.2.50.113.B.(11) NMAC (emphasis added). Subparagraph (b) of Paragraph (11) of Subsection B of 20.2.50.113 NMAC requires the owner or operator "[p]repare a demonstration detailing why

emissions from the individual engine or turbine cannot be addressed through an ACP in a technically practicable or economically feasible manner." Thus, this demonstration does not require the submission of a comprehensive ACP, but does require a *reasonable* (but not exhaustive) showing that the target emission standards for these individual turbines are not technically practicable or economically feasible, even through an ACP.

Regarding technical practicability and economic feasibility, in particular, the EIB adopted Paragraphs (10) and (11) of Subsection B of 20.2.50.113 NMAC "for the reasons stated in the NMED Rebuttal . . . and the supporting argument by Kinder Morgan." State of New Mexico, Environmental Improvement Board, Statement of Reasons and Final Order, In the Matter of Proposed New Regulation 20.2.50 NMAC – Oil and Gas Sector – Ozone Precursor Pollutants, No. EIB 21-27, at pp. 111 (June 27, 2022) (hereinafter, Statement of Reasons). In particular, and citing to Kinder Morgan's supporting argument in the EIB rulemaking, the EIB stated that "[w]hile the emissions thresholds provided in Tables 1 and 3 for existing engines and turbines are appropriate in most cases, circumstances may exist where it is technically impracticable or economically infeasible to achieve compliance." Id. at 111. Recognizing these practical limitations, the EIB's final rule "offers significant flexibility for sources that are unable to meet the emissions standards of Part 50: they may reduce the annual hours of operation, they may seek an Alternative Compliance Plan ACP to meet an equivalent amount of emission reductions, and/or they may seek alternative emissions standards if they can demonstrate that they cannot meet the existing standards through an ACP." Id. at 111 (emphasis added). Thus, an operator may have in place both an AES (or multiple AESs for individual units), and an ACP. Further to costs, the EIB made clear that "[c]ost-effectiveness thresholds above which a certain control technology will be considered infeasible can vary, but, in general, the Department considers costs in excess of $7,500 per ton of pollutant reduced to be infeasible." Id.

EPNG is requesting an AES for NOx for these 10 existing GE gas turbines on the basis that achieving the Table 3 emission standards found in 20.2.50.113 NMAC is economically infeasible. The 10 GE gas turbines subject to the AES proposal are subject to the NOx emission standard of 50 ppmvd @15% O_2. EPNG converted the emission standard to pounds per hour (pph) for each GE gas turbine subject to the AES proposal. The allowable annual emission rates under the Ozone Precursor rule are calculated by converting the pph emission rates to an annual basis assuming continuous operation (8,760 hr/yr). The required emission reductions are calculated as the difference between the current permit limits (tpy) and the allowable annual emission rates (tpy) under the Ozone Precursor rule. The combined total permitted NOx emissions for the 10 GE turbines is 2,082.4 tpy. The total allowable NOx emissions under the Ozone Precursor rule, 20.2.50.113.B NMAC (Table 3), for the 10 GE turbines is 452.0 tpy by January 1, 2028. Therefore, the total required NOx emission reductions for the 10 GE turbines is 1,630.4 tpy, to be incrementally achieved, by January 1, 2028. See 20.2.50.113.B.(7) NMAC. A summary of allowable emissions under the rule and the reductions proposed by the AES for the 10 GE turbines is listed below in Table 2-2.

Table 2-2 Allowable Emissions and Proposed Reductions for 10 GE Turbines

Units	Permitted NOx Emissions (tpy)	Allowable Hourly NOx Emissions (pph) (equivalent of 50 ppmvd @15% O_2)	Allowable Annual NOx Emissions Complying the Rule (tpy)	NOx Reduction Required by the Rule (tpy)	NOx Reduction Proposed by AES (tpy)
Afton A-1	224.5	11.3	49.5	175.0	23.0
Afton A-2	224.5	11.3	49.5	175.0	23.0
Afton A-3	224.5	11.3	49.5	175.0	23.0
Belen A-1	169.0	7.7	33.7	135.3	77.5
Belen A-2	169.0	7.7	33.7	135.3	77.5
Caprock A-1	201.0	12.3	53.9	147.1	20.5
Caprock A-2	172.1	7.7	33.7	138.4	80.5
Pecos River A-1	232.6	11.3	49.5	183.1	31.1
Pecos River A-2	232.6	11.3	49.5	183.1	31.1
Pecos River A-3	232.6	11.3	49.5	183.1	31.1
Total	**2,082.4**		**452.0**	**1,630.4**	**418.3**

Kinder Morgan is in the process of developing an Alternate Compliance Plan (ACP) for the engines and turbines subject to the rule operated by Kinder Morgan or its affiliates and subsidiaries, including EPNG, TransColorado Gas Transmission Co., LLC, and Natural Gas Pipeline Company of America, LLC. The ACP will be submitted in accordance with 20.2.50.113(B)(10). The 10 GE turbines are excluded from the ACP for NOx emissions because they cannot meet the emission standards through an ACP for the following reasons:

- Technology limits the available control options for the 10 GE turbines to Selective Catalytic Reduction (SCR). See Section 3 (Potential Control Technology Review).
- Installing SCR on the 10 GE turbines is not economically feasible. See Section 4 (Cost Analysis and Proposed Alternative Emissions Standards); see also Appendix A-1 (Control Cost Estimate Based on Potential to Emit for El Paso Natural Gas Company GE Turbines); Appendix [A-2] (Control Cost Estimate Based on Actual Emissions for El Paso Natural Gas Company GE Turbines).
- Including the 10 GE turbines in an ACP with the remainder of Kinder Morgan's fleet is not possible. See Section 5 (Exclusion from ACP).

Notwithstanding the lack of cost effective control strategies, the inability to address via an ACP, and the limitations on reducing hours of operations or capacity, Kinder Morgan has proposed reductions in permit allowable emission rates

for NOx. Under the proposed AES, Kinder Morgan proposes to reduce 418.3 tons of NOx emission annually combined from the 10 GE gas turbines. See Section 6 (Proposed Alternative Emission Standards).

3 Potential Control Technologies Review

Potential control technologies and their feasibility are discussed in Section 3.1. The technical feasibility of the available control technologies is summarized in Section 3.2.

3.1 Potentially Available Control Technologies and Technical Feasibility Evaluation

Potentially available control technologies to reduce NO_X from the stationary natural gas-fired combustion turbines are summarized below. The technical feasibility of installation of each control technology is also evaluated for the ten turbines.

3.1.1 Water or Steam Injection

Water or steam injection operates by introducing water or steam into the flame area of the gas turbine combustor. The injected fluid provides a heat sink that absorbs some of the heat of combustion, thereby reducing the peak flame temperature and the formation of thermal NO_X. The water injected into the turbine must be of high purity such that no dissolved solids are injected into the turbine. Dissolved solids in the water may damage the turbine due to corrosion and/or the formation of deposits in the hot section of the turbine. The requirement of high-purity water can be expensive to retrofit because EPNG does not have water treatment systems on-site. Moreover, the consumption of water can be very high for a large turbine. Such high water usage may pose problems for the local water supply and is an added expense. This is important, especially in dry regions such as New Mexico. Although water/steam injection acts to reduce NO_X emissions, the lower average temperature within the combustor may produce higher levels of CO and hydrocarbons because of incomplete combustion. Additionally, water/stream injection results in a decrease in combustion efficiency and an increase in maintenance requirements due to wear on the turbine and combustor.

Water or steam injection is not, however, available for all types of unit. The ten turbines included in this request are GE Frame 3 turbines. Based on feedback from GE representatives, water or steam injection technology is not available to the GE Frame 3 gas turbines. Accordingly, this NOx control method is not technically feasible. See Appendix A-3 (Letter from Baker Hughes dated October 16, 2019 and provided in the Ozone Precursor rulemaking as attachment T to Kinder Morgan's rebuttal technical testimony).

3.1.2 Lean Head End Combustion Liner Upgrade and Dry Low-NOX (DLN) Combustors

The liner of a turbine surrounds the combustion process and allows for various airflows to pass through into the combustion zone. The liner is subject to high temperatures due to the combustion process which it contains. Because of this, the life of the liner is limited. Replacing the old combustion liner with a new, upgraded liner is a common retrofit. Combustion liners have a limited lifespan and are designed to be replaced.

Lean pre-mix technology, also referred to as dry low-NOX (DLN) combustion technology, is a pollution prevention technology that controls NO_X emissions. DLN inhibits the conversion of atmospheric nitrogen

to NO_X in the turbine combustor. This is accomplished by reducing the combustor temperature using lean mixtures of air and/or fuel staging or by decreasing the residence time of the combustor through combustion chamber design. For existing turbines, the combustion chamber would need to be redesigned and reconfigured to allow for lean pre-mixing or fuel staging.

In lean combustion systems, excess air is introduced into the combustion zone to produce a significantly leaner fuel/air mixture than is required for complete combustion. This excess air reduces the overall flame temperature because a portion of the energy released from the fuel must be used to heat the excess air to the reaction temperature. Pre-mixing the fuel and air prior to introduction into the combustion zone provides a uniform fuel/air mixture and prevents localized high-temperature regions within the combustor area. The fuel-to-air ratio must be maintained within a relatively narrow range to obtain low NO_X without blowout and without increasing carbon monoxide (CO) emissions, which are generated during incomplete combustion.[1] Since NO_X formation rates are an exponential function of temperature, turbines having frequent and rapid load changes may experience a brief spike in NO_X emissions with DLN technology.

Based upon feedback from GE, DLN control technology combined with a liner upgrade is not available to GE Frame 3 Models A and C turbines; therefore, this is not a technically feasible technology.

3.1.3 EM_X/$SCONO_X$

EM_X™ (the second generation of the $SCONO_X$ NO_X Absorber Technology) utilizes a coated oxidation catalyst to remove both NO_X and CO without a reagent, such as NH_3. Hydrogen (H_2) is used as the basis for the proprietary catalyst regeneration process. The $SCONO_X$ system consists of a platinum-based catalyst coated with potassium carbonate to oxidize NO and CO. The NO_2 molecules are subsequently absorbed on the treated surface of the $SCONO_X$ catalyst. The catalyst is installed in the flue gas with a temperature range between 300°F to 700°F.[2]

The EM_X™/$SCONO_X$™ catalyst system is designed to operate effectively at temperatures ranging from 300 to 700 °F. The 10 GE turbines requiring AES have an exhaust temperature of approximately 850-950°F.[3]

EM_X™/$SCONO_X$™ applications on turbines with outlet temperatures this high have not been identified. Consequently, EM_X™/$SCONO_X$™ is not technically feasible for the control of NO_X emissions from the 10 GE turbines.

3.1.4 Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is a post-combustion gas treatment process in which urea or ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, ammonia and nitric oxide (NO) react to form diatomic nitrogen and water vapor. The chemical reactions can be expressed as:

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[1] "Retrofitability of DLN/DLE system," GE Technology Insights 2013.
[2] BACT Analysis for JEA-Greenland Energy Center Units 1 and 2, Combined Cycle Combustion Turbines. Prepared by Black & Veatch (September 2008).
[3] Per average of 2016, 2017, and 2018 emissions test summaries.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 \rightarrow 3\ N_2 + 6\ H_2O$$

When operated within the optimum temperature range, the reaction can result in removal efficiencies of 90 percent.[4] In order for the SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 and 850 °F), dependent on the material of the catalyst. SCR units have the ability to function effectively under fluctuating temperature conditions, although fluctuation in exhaust gas temperature reduces removal efficiency slightly by disturbing the NH_3/NO_X molar ratio. SCR installations typically have an operating range of 450 to 850ºF. The exhaust temperatures of the turbines included in this evaluation are approximately 850-950ºF, which is higher than the typical SCR operating range. SCRs may operate at higher temperatures but this generally results in lower efficiencies (between 70-85%).[5] SCR is therefore considered technically feasible.

It should be noted that there are several operational issues that may inhibit the effectiveness of SCR as a control option for turbines at natural gas compressor stations. The NH_3/NO_X molar ratio of 1:1 must be carefully controlled to allow for optimum NO_X reduction while limiting the amount of unreacted NH_3 emitted to the atmosphere (known as "ammonia slip"). This ratio is difficult to control in units that have the variable loads experienced at compressor stations. The unit loading and speed of the turbines fluctuate continually according to the time of day, changes in the weather, and customer demands. Throughout the day, units are started and stopped, and loads are changed to keep pipeline operating pressures within safe operating parameters and keep volumes sufficient to meet customer obligations. Although the variable nature of compressor station turbine loads does not make SCR operation technically infeasible, the inherent lag between CEM sampling and ammonia injection for the turbines may cause hourly NO_X emission limits to be exceeded during periods of increased load and unreacted NH_3 emissions ("ammonia slip") to increase during periods of load loss.

3.1.5 Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion NO_X control technology based on the reaction of urea or ammonia with NO_X. In the SNCR chemical reaction, urea [$CO(NH_2)_2$] or ammonia is injected into the combustion gas path to reduce the NO_x to nitrogen and water. The overall reaction schemes for both urea and ammonia systems can be expressed as follows:

$$CO(NH_2)_2 + 2\ NO + ½\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$$
$$4\ NH_3 + 6NO \rightarrow 5\ N_2 + 6\ H_2O$$

[4] U.S. EPA, Office of Air Quality Planning and Standards. OAQPS Control Cost Manual Section 4-2 Chapter 2, updated on June 12, 2019.

[5] U.S. EPA, Office of Air Quality Planning and Standards. OAQPS Control Cost Manual Section 4-2 Figure 2.2, updated on June 12, 2019.

Typical removal efficiencies for SNCR range from 40 to 60 percent.[6] An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600 to 2,000°F.[7] Operation at temperatures below this range results in ammonia slip (when non-reacted NH_3 is emitted to the atmosphere). The temperature range required for the effective operation of this technology is above the peak exhaust temperature for the GE gas turbines assessed here. For this reason, it has been determined that this control technology is not feasible for the GE gas turbines at EPNG facilities.

3.1.6 Replacement with Electric Drive

In anticipation of potential comments, EPNG documents in this submission that replacement of these 10 turbines with electric motors is neither required by the applicable rule.

In particular, in the context of existing sources in particular, the Department's purpose is to identify "control" opportunities. See NMSA 1978, Section 74-2-5(C) (providing the EIB authority to adopt a plan "to control emissions of oxides of nitrogen . . . .") (emphasis added). The use of "control" here contemplates that emissions sources will install controls to reduce emissions—not eliminate or replace those emissions sources altogether. See West Virginia v. EPA, 142 S. Ct. 2587, 2612 n.3 (2022) ("Section 111(d) empowers EPA to guide States in establishing standards of performance for existing sources, not to direct existing sources to effectively cease to exist.") (internal quotations and citations omitted). Cf. Sierra Club v. EPA,499 F.3d 653, 657 (7th Cir. 2007) (not requiring a control technology that would "redefine the source" in the context of new source permitting).

3.1.7 Good Combustion Practices (base case)

NO_X emissions are caused by the oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the combustion chamber, where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for the operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for the equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection were identified in this review for the control of NO_X emissions from combustion turbines; therefore, it has been determined that this method of NO_X control is feasible for the GE gas turbines at EPNG facilities. EPNG has developed Turbine Inspection and Maintenance Schedules Best Practices procedures, which are based on manufacturer recommendations, and EPNG has systems in place to ensure that its turbines are operated and maintained in accordance with these procedures. These practices are currently in use at all facilities, and the PTE is reflective of operations following good combustion practices. No further assessment of these control practices is included in this report.

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[6] U.S. EPA, Office of Air Quality Planning and Standards. OAQPS Control Cost Manual Section 4-2 Chapter 1, updated on April 25, 2019.

[7] U.S. EPA, Clean Air Technology Center. Oxides of nitrogen (NOX), Why and How They Are Controlled. Research Triangle Park, North Carolina. p. 18, EPA-456/F-99-006R, November 1999.

3.2 Technical Feasibility Summary

The technical feasibility of potential control technologies is summarized in Table 3-1.

Table 3-1 Technical Feasibility of NO_X Emission Control Technologies for 10 GE Turbines

Section	Technology	Technically Feasible?
3.1.1	Water or Steam Injection	No
3.1.2	Lean Head End Combustion Liner Upgrade and Dry Low-NOX (DLN) Combustors	No
3.1.3	EM_X/$SCONO_X$	No
3.1.4	SCR	Yes
3.1.5	SNCR	No
3.1.7	Good Combustion Practices	Yes

4 Cost Analysis

4.1 Cost of Compliance

Economic impacts were analyzed using vendor cost estimates along with the procedures found in the EPA Air Pollution Control Cost Manual (CCM) as applicable. The sources of the control equipment cost data are noted in each of the control cost analysis worksheets in Appendix A-1 and Appendix A-2.

Overall, economic feasibility is evaluated on a dollar-per-ton ($/ton) basis using the annual operating cost ($/year) divided by the annual emission reduction achieved by the control device (ton/yr). The initial capital cost was annualized over a 25-year period and added to the annual operating costs, and the interest rate reflects EPNG's actual cost of borrowing. To be conservative in the cost analysis, the highest actual performance test data plus 20% safety factor is used to calculate the annual emission reduction rates. EPNG compared the cost-effectiveness to a $7,500/ton threshold to evaluate if the control is economically feasible.[8] This cost threshold is cited in the preamble to rulemaking for 20.2.50 NMAC and has been utilized by other states to define an acceptable level for determination of cost effectiveness for control technologies. EPNG calculated cost-per-ton estimates based on actual historic emissions as well as potential emissions. As shown above and below, the economic feasibility values (under both scenarios displayed) are above $7,500 for all 10 GE turbine units.

4.1.1 Control Cost Effectiveness Evaluation

The details of the turbine control cost effectiveness evaluation based on potential emissions are included in Appendix A-1 and Appendix A-2. The findings of the economic analysis based on the average actual annual emissions from 2018 to 2020 and PTE are summarized in Table 4-1.

[8] Statement of Reasons, at 111 ("[I]n general, the Department considers costs in excess of $7,500 per ton of pollutant reduced to be in feasible.").

Table 4-1 Cost Effectiveness of SCR for the Turbines

Turbine Location	Unit No.	Cost Effectiveness ($/ton NO_x Removed) Based on Actual Emissions	Cost Effectiveness Based on PTE ($/ton NO_X Removed)	Cost Effective?
Afton	A-01	$123,236	$11,697	No
Afton	A-02	$458,302	$11,097	No
Afton	A-03	$48,516	$11,097	No
Belen	A-01	$88,704	$30,794	No
Belen	A-02	$60,982	$29,214	No
Caprock	A-01	$80,398	$9,933	No
Caprock	A-02	$54,935	$29,283	No
Pecos River	A-01	$27,877	$8,261	No
Pecos River	A-02	$22,517	$11,097	No
Pecos River	A-03	$26,527	$11,097	No

Regarding Table 4-1, the data in the third column are from Kinder Morgan's Technical Testimony filed on July 28, 2021 before the EIB in which KM used the average actual emissions from 2018 to 2020. This data was ultimately relied upon by the EIB in support of adoption of Paragraphs (10) and (11) of Subsection B of 20.2.50.113 NMAC, which are the options to comply with the emissions limits through an AES or ACP. See State of New Mexico, Environmental Improvement Board, Statement of Reasons and Final Order, In the Matter of Proposed New Regulation 20.2.50 NMAC – Oil and Gas Sector – Ozone Precursor Pollutants, No. EIB 21-27, at pp. 100-101 (June 27, 2022) (hereinafter, Statement of Reasons). Notably, in NMED's rebuttal testimony (Ex. 1) during the Ozone Precursor rulemaking, the agency had raised questions with respect to how Kinder Morgan arrived at its cost-per-ton estimates, inquiring into the use of actual operating hours and actual emissions data. See NMED Ex. 1, at 46–48 (performing an estimation of cost effectiveness based on "full permitted capacity," i.e., PTE). In response, Kinder Morgan presented sur-rebuttal testimony on September 20, 2021 responsive to the Department's questions. In that sur-rebuttal testimony, Kinder Morgan presented additional cost-per-ton analyses using averaged operating costs over a 10-year period. The analysis demonstrated that the actual hours of operation/actual emissions were reasonably applied in the original analysis, and the cost-per-ton remained well above the reasonableness threshold of $7,500 per ton of NOx reduced. Based on this discussion and these findings, the Department presented and the EIB approved Paragraphs (10) and (11) of Subsection B of 20.2.50.113 NMAC to account for technical practicality and economic reasonableness, as required by statute. NMSA § 74-2-105(F) (requiring that the EIB "shall give weight it deems appropriate to . . . technical practicability and economic reasonableness of reducing or eliminating air contaminants . . ."). This approach, to consider historical actual emissions is further consistent with the recommendation made by the Western

Regional Air Partnership (WRAP) when conducting the four-factor analysis for Regional Haze.[9] These data show that this path forward is, without a doubt, not cost-effective.

Finally, the last column shows cost-ineffectiveness calculations based on the more conservative PTE scenario.

As demonstrated by the data in Table 1-1 and the enclosed Appendices, even if the Department considers the overly conservative approach of using PTE to estimate the cost-per-ton, installation of SCR remains cost ineffective.

Based on the information provided in Table 4-1, the only available control technology for the 10 GE turbines, SCR, was considered to be economically infeasible.

[9] Supplementary Information for Four Factor Analyses by WRAP States, Revised Draft Report (April 20, 2010); see also ADEQ Regional Haze State Implementation Plan 2028, Emissions Projection Methodology; 40 C.F.R. Part 51, Appendix Y (discussing in relevant part how to calculate baseline emissions for the purpose of cost-effectiveness analysis for Best Available Retrofit Technology, which should "represent a realistic depiction of the anticipated annual emissions for the source. . . . you will estimate the anticipated annual emissions based upon actual emissions from a baseline period.").

5 Exclusion from ACP is Appropriate

5.1 The 10 GE Turbines cannot be Incorporated into an ACP

As noted above, Subparagraph (b) of Paragraph (11) of Subsection B of 20.2.50.113 NMAC requires the owner or operator "[p]repare a demonstration detailing why emissions from the individual engine or turbine cannot be addressed through an ACP in a technically practicable or economically feasible manner." This demonstration does not require the submission of a comprehensive ACP, but does require a reasonable analysis showing that the target emissions standards for these individual turbines are not technically practicable or economically feasible, even through an ACP. This Section 5 is responsive to this requirement.

An ACP must include the list of engines or turbines subject to the ACP, and a demonstration that the total allowable emissions for the engines or turbines subject to the ACP will not exceed the total allowable emissions under the emission standards of this Part. See 20.2.50.113. B.(7) NMAC. Kinder Morgan cannot satisfy this requirement if it includes the 10 GE turbines in the ACP. Total allowable NOx emissions under the rule for the rest of Kinder Morgan's entire fleet consisting of 17 engines and nine (9) non-GE turbines (26 units in total), excluding the 10 GE turbines, is 1,064.6 tpy. If the GE turbines in question were included in the ACP, the required reduction from the 10 GE turbines alone would be 1,630.4 tpy, an amount that exceeds the total allowable emissions from the 26 units that comprise the remainder of Kinder Morgan's fleet subject to the rule. Even if the 26 non-GE units were entirely shut down, Kinder Morgan could not achieve the required reductions while still operating the 10 GE turbines.

Furthermore, shutting down or reducing the capacity of the fleet of GE turbines, is not a feasible option at this time. The GE turbines, and in fact, the entire fleet of Kinder Morgan engines and turbines, are part of interstate natural gas pipelines that are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the federal Natural Gas Act. See, e.g., 18 C.F.R. § 284.7(a) (setting forth requirements for interstate natural gas firm transportation service). FERC approves or "certificates" the pipeline to deliver natural gas. Kinder Morgan's entire pipeline system, as certificated by FERC, is based on the fact that Kinder Morgan can move gas 24 hours a day, 365 days a year at its designed capacity. Shutting down one or more of the company's turbines or engines would require that Kinder Morgan seek and obtain approval from FERC to abandon these units. In addition to being a lengthy administrative process, it is unlikely that FERC would approve shutting down the 10 GE turbines because it would diminish Kinder Morgan's ability to meet its obligations under the Natural Gas Act, drive up the cost of natural gas in the southwest United States, and deprive downstream consumers in New Mexico and other states of clean-burning natural gas to heat their homes and cook their food. Notably, multiple recent news articles and industry studies have discussed the relationship between market prices and pipeline

capacity or deliverability. For example, an NGI article from January 20, 2023 discussed the high prices in New England caused by lack of adequate pipeline delivery capacity to into the region.[10]

Additionally, market conditions project stable, if not increased, demand for natural gas. The Energy Information Administration's 2023 Annual Energy Outlook (AEO) analyzes long-term energy trends in the United States. In the context of the energy transition, while the AEO anticipates growth in renewable generating capacity, relative to 2022, the AEO projects that "natural gas generating capacity ranges from an increase of between 20% to 87% through 2050."[11] The AEO also concludes that "[d]espite the shift toward renewable sources and batteries in electricity generation, domestic natural gas consumption remains relatively stable," however, "Natural gas production . . . in some cases continues to grow in response to international demand for liquefied natural gas, supported by associated natural gas produced along with crude oil."[12]

In summary, at this time, shutting down or reducing capacity of the GE turbines as part of an ACP is not a viable solution.

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[10] Natural Gas Intelligence, "New England Gas Prices Soared in 2022 Amid Stiffer Global LNG Competition," (Jan. 20, 2023), *available at* https://www.naturalgasintel.com/haynesville-output-to-top-16-bcf-d-as-total-lower-48-production-continues-to-climb/.

[11] U.S. Energy Information Administration, Annual Energy Outlook 2023 (March 16, 2023) [hereinafter, AEO], *available at* https://www.eia.gov/outlooks/aeo/narrative/index.php ("Despite the growth in adopting heat pumps, natural gas-fired heating equipment, including furnaces and boilers, continue to account for the largest share of energy consumption for space heating in U.S. residential and commercial buildings across all cases through 2050.").

[12] See AEO, at Figures 14 and 17.

6 EPNG's Proposed Alternative Emissions Standards

Notwithstanding the limitations EPNG faces with respect to the 10 GE turbines, and to demonstrate its commitment to reasonable emissions reductions, EPNG will reduce its permitted limits as part of the AES. In particular, after a detailed review of testing conducted on the 10 GE Frame 3 turbines and similar turbines in Kinder Morgan's nationwide fleet, Kinder Morgan has identified achievable reductions in permitted NOx emissions for these GE turbines. Thus, EPNG has proposed 418.3 tpy of NOx emissions reductions (see Table 2-2) from the current permitted allowable NOx emissions for these GE Frame 3 turbines.

6.1 Proposed Alternative Emission Standards

Under 20.2.50.113.B(11), the Ozone Precursor rule states an owner or operator may submit a request for AES for a specific engine or turbine based on technical impracticability or economic infeasibility.

EPNG expects the turbine operation in the future to be similar to current operations. However, turbine operation is highly dependent on product demand, weather patterns, pipeline maintenance, and upstream/downstream pipeline impacts. These factors create a considerable amount of uncertainty as to the expected annual operating hours of each turbine for a specific year, and make hours limitations impracticable.

Thus, to be conservative in establishing the AES, the operating hours were assumed to be 8,760 hours per year. In order to maintain an acceptable margin to compliance, EPNG calculated the AES using the highest hourly performance test data for each model with a 20% safety factor and 8,760 operating hours per year. The resulting emissions are lower than permitted emissions for each turbine but are more representative of the physical and operational design at the locations these turbines are installed. Specifically, the combined proposed annual NOx emissions from the 10 GE turbines show a reduction of 418.3 tons compared to the current permitted values. Kinder Morgan believes these reductions demonstrate a good faith effort to meet the requirements of the rule to the best of our ability given cost, technology, and national regulatory obligations.

EPNG is proposing to accept these AES as enforceable emission limitations. Because the emission standards found in 20.2.50.113 NMAC are in units of parts per million by volume (ppmvd), expressed on a dry basis at 15 percent oxygen (15% O_2), EPNG converted the AES in pph to ppmvd @15% O_2. The proposed AES for each turbine are presented in Table 6-1, and the reduction in emissions, as compared with annual permitted emissions, are shown in Table 6-2.

Table 6-1 Proposed Alternative Emissions Standards for NOx in pph and ppmvd@15% O_2

Turbine Location	Unit No.	Proposed Hourly NOx Emissions	Proposed Annual NO_X Emissions	Proposed NOx Limit (ppmvd@15% O2)
Afton	A-01	46.0 pph	201.5 tpy	202
Afton	A-02	46.0 pph	201.5 tpy	202
Afton	A-03	46.0 pph	201.5 tpy	202
Belen	A-01	20.9 pph	91.5 tpy	131
Belen	A-02	20.9 pph	91.5 tpy	131
Caprock	A-01	41.2 pph	180.5 tpy	169
Caprock	A-02	20.9 pph	91.6 tpy	131
Pecos River	A-01	46.0 pph	201.5 tpy	202
Pecos River	A-02	46.0 pph	201.5 tpy	202
Pecos River	A-03	46.0 pph	201.5 tpy	202
Total			1,664.1	

Table 6-2 Annual NOx Emissions Comparisons between Current Permit and Proposed AES

Turbine Location	Unit No.	Annual NOx Permit Limit (tpy)	Proposed Annual NOx Emissions (tpy)	NOx Reduction Proposed by AES (tpy)
Afton	A-01	224.5	201.5	23.0
Afton	A-02	224.5	201.5	23.0
Afton	A-03	224.5	201.5	23.0
Belen	A-01	169.0	91.5	77.5
Belen	A-02	169.0	91.5	77.5
Caprock	A-01	201.0	180.5	20.5
Caprock	A-02	172.1	91.6	80.5
Pecos River	A-01	232.6	201.5	31.1
Pecos River	A-02	232.6	201.5	31.1
Pecos River	A-03	232.6	201.5	31.1
Total		2,082.4	1,664.1	418.3

In order to convert from pph to ppmvd@15% O_2, the following inputs are needed: $\%O_2$ measured in the test, high heating value (HHV) of natural gas, fuel specific EPA F-Factor (dscf/mmBtu), conversion factor for NOx from ppm to lb/dscf, and fuel flow of natural gas measured in the test (scfh). Because Pecos River A-03 had the highest hourly tested emission rate for GE model MS3712R-A, it is used in the sample calculation below to convert the hourly NOx emission rate to ppmvd@15% O_2.

Inputs: $\%O_2$ measured during test = 18.92%
HHV of pipeline quality natural gas = 1,032 Btu/scf
Fuel specific EPA F-Factor determine during test = 8,694 dscf/mmBtu
Conversion factor for NOx = (ppm x 1.194E-07)
Fuel flow measured in test = 59,867 scfh
Proposed AES NOx hourly emission rate = 46.0 lb/hr

lb/mmscf = 46.0 (lb/hr) x 1,000,000 (scf/1 mmscf) / 59,867 (scf/hr) = 768.04
lb/mmBtu = 768.04 (lb/mmscf) / 1,032 (Btu/scf) = 0.744
Concentration (lb/dscf) = 0.744 (lb/mmBtu) x ((20.9-%O2)/20.9) / 8,694 (dscf/mmBtu) = 8.11E-06
Bias corrected concentration (ppm) = 8.11E-06 / (1,194E-07) = 67.9
Bias corrected concentration (ppmvd@15% O2) = 67.9 x 5.9 / (20.9-$\%O_2$) = 202

Appendix A-1

Control Cost Estimate Based on Potential to Emit for El Paso Natural Gas Company GE Turbines

El Paso Natural Gas Company, LLC

Afton Compressor Station - 50 ppmvd NOx based on PTE

Unit: A-01	Interest Rate:		8.53%	<-- EPNG Actual Interest Rate
GE Model M3712R Turbine	Period (yrs):		25	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_X lb/hr:		46.00	lb/hr	<--highest actual test data for GE M3712R-A plus 20% safety factor
NO_X tpy:		201.48	tpy	
				<-- Calculated using the highest actual test data plus 20% and 8760 operating hours.
SCR				
NO_X Reduction:		75.5%		<-- Reach the 50 ppmc Nox limit
NO_X lb/hr:		11.25	lb/hr	<-- Based on highest test result of GE M3712R-A at equivalent reduction to 50 ppmvd.
NO_X tpy:		49.28	tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	13,258,524		<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP)
Total Capital Investment	$	13,258,524		
Annualized TCI:	$	1,298,747		<-- Based on interest rate, year and TCI
Annual Administrative Costs:	$	3,424		<-- Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	478,225		<-- Annual Cost Estimate (A-01)
Total Annual Costs:	$	1,780,396		
Emissions Reduction:		152.2	tpy	
Cost Effectiveness:	**$**	**11,697.36**	**$/ton**	

Afton Unit A-01: Cost Estimate

Total Capital Investment (TCI) =	$ 13,258,524

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$478,225
Indirect Annual Costs (IDAC) =	$1,302,171
Total annual costs (TAC) = DAC + IDAC	$1,780,396

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$66,293	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at 100% full load, ammoniaconsumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$478,225	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,424
Capital Recovery Costs (CR)=	CRF x TCI =	$1,298,747
Indirect Annual Cost (IDAC) =	AC + CR =	$1,302,171

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,780,396	Per Year
NOx Removed =	152.2	tons/year
Cost Effectiveness =	$11,697.36	

El Paso Natural Gas Company, LLC

Afton Compressor Station - 50 ppmvd NOx based on PTE

Unit: A-02	Interest Rate:		8.53%	<-- EPNG Actual Interest Rate
GE Model M3712R Turbine	Period (yrs):		25	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_x lb/hr:		46.00	lb/hr	<--highest actual test data for GE M3712R-A plus 20% safety factor
NO_x tpy:		201.48	tpy	<-- Calculated using the highest actual test data plus 20% and 8760 operating hours.
SCR				
NO_x Reduction:		75.5%		<-- Reach the 50 ppmc Nox limit
NO_x lb/hr:		11.25	lb/hr	<-- Based on highest test result of GE M3712R-A at equivalent reduction to 50 ppmvd.
NO_x tpy:		49.28	tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	12,371,394		<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP) +$1MM cost increase
Total Capital Investment	$	12,371,394		
Annualized TCI:	$	1,211,848		<-- Based on interest rate, year and TCI
Annual Administrative Costs:	$	3,370		<-- Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	473,790		<-- Annual Cost Estimate (A-02)
Total Annual Costs:	$	1,689,008		
Emissions Reduction:		152.2	tpy	
Cost Effectiveness:	**$**	**11,096.93**	**$/ton**	

Afton Unit A-02: Cost Estimate

Total Capital Investment (TCI) =	$ 12,371,394

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$473,790
Indirect Annual Costs (IDAC) =	$1,215,218
Total annual costs (TAC) = DAC + IDAC	$1,689,008

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$61,857	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at full load, ammonia cobsumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 base on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$473,790	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,370
Capital Recovery Costs (CR)=	CRF x TCI =	$1,211,848
Indirect Annual Cost (IDAC) =	AC + CR =	$1,215,218

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,689,008	Per Year
NOx Removed =	152.2	tons/year
Cost Effectiveness =	$11,096.93	

El Paso Natural Gas Company, LLC

Afton Compressor Station - 50 ppmvd NOx based on PTE

Unit: A-03	Interest Rate:		8.53%	<-- EPNG Actual Interest Rate
GE Model M3712R Turbine	Period (yrs):		25	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_X lb/hr:		46.00	lb/hr	<--highest actual test data for GE M3712R-A plus 20% safety factor
NO_X tpy:		201.48	tpy	<-- Calculated using the highest actual test date plus 20% and 8760 operating hours.
SCR				
NO_X Reduction:		75.5%		<-- Reach the 50 ppmc Nox limit
NO_X lb/hr:		11.25	lb/hr	<-- Based on highest test result of GE M3712R-A at equivalent reduction to 50 ppmvd.
NO_X tpy:		49.28	tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	12,371,394		<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP) +$1 MM cost increase per vendor
Total Capital Investment	$	12,371,394		
Annualized TCI:	$	1,211,848		<-- Based on interest rate, year and TCI
Annual Administrative Costs:	$	3,370		<-- Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	473,790		<-- Annual Cost Estimate (A-03)
Total Annual Costs:	$	1,689,008		
Emissions Reduction:		152.2	tpy	
Cost Effectiveness:	**$**	**11,096.93**	**$/ton**	

Afton Unit A-03: Cost Estimate

Total Capital Investment (TCI) =	$ 12,371,394

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$473,790
Indirect Annual Costs (IDAC) =	$1,215,218
Total annual costs (TAC) = DAC + IDAC	$1,689,008

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$61,857	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at full load, ammonia consumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$473,790	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,370
Capital Recovery Costs (CR)=	CRF x TCI =	$1,211,848
Indirect Annual Cost (IDAC) =	AC + CR =	$1,215,218

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,689,008	Per Year
NOx Removed =	152.2	tons/year
Cost Effectiveness =	$11,096.93	

El Paso Natural Gas Company, LLC

Belen Compressor Station - 50 ppmvd NOx based on PTE

Unit: A-01	Interest Rate:		8.53%	<-- EPNG Actual Interest Rate
GE Model M3572R Turbine	Period (yrs):		25	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_x lb/hr:		20.90	lb/hr	<--highest actual test date for GE M3572R-C plus 20% safety factor
NO_x tpy:		91.54	tpy	
				<-- Calculated using the highest actual test data plus 20% and 8760 operating hours.
SCR				
NO_x Reduction:		63.2%		<-- Reach the 50 ppmc NOx limit
NO_x lb/hr:		7.70	lb/hr	<-- Based on highest test result of GE M3572R-C at equivalent reduction to 50 ppmvd.
NO_x tpy:		33.73	tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	13,258,524		<-- CE2107005 Caprock internal est 07/16/2021 + $1 MM cost increase per vendor June 2022 letter
Total Capital Investment	$	13,258,524		
Annualized TCI:	$	1,298,747		<-- Based on interest rate, year and TCI
Administrative Costs:	$	3,424		<--Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	478,225		<-- Annual Cost Estimate (A-01)
Total Annual Costs:	$	1,780,396		
Emissions Reduction:		57.8	tpy	
Cost Effectiveness:	**$**	**30,794.18**	**$/ton**	

Belen Unit A-01: Cost Estimate

Total Capital Investment (TCI) =	$ 13,258,524

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$478,225
Indirect Annual Costs (IDAC) =	$1,302,171
Total annual costs (TAC) = DAC + IDAC	$1,780,396

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$66,293	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at 100% full load, ammonia consumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$478,225	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,424
Capital Recovery Costs (CR)=	CRF x TCI =	$1,298,747
Indirect Annual Cost (IDAC) =	AC + CR =	$1,302,171

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,780,396 Per Year
NOx Removed =	57.8 tons/year
Cost Effectiveness =	$30,794.18

El Paso Natural Gas Company, LLC

Belen Compressor Station - 50 ppmvd NOx based on PTE

Unit: A-02	Interest Rate:		8.53%	<-- EPNG Actual Interest Rate
GE Model M3572R Turbine	Period (yrs):		25	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_X lb/hr:		20.90 lb/hr		<--highest actual test date for GE M3572R-C plus 20% safety factor
NO_X tpy:		91.54 tpy		<-- Calculated using the highest actual test data plus 20% and 8760 operating hours.
SCR				
NO_X Reduction:		63.2%		<-- Reach the 50 ppmc NOx limit
NO_X lb/hr:		7.70 lb/hr		<-- Based on highest test result of GE M3572R-C at equivalent reduction to 50 ppmvd.
NO_X tpy:		33.73 tpy		<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	12,371,394		<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP) + $1 MM cost increase per vendor
Total Capital Investment	$	12,371,394		
Annualized TCI:	$	1,211,848		<-- Based on interest rate, year and TCI
Administrative Costs:	$	3,370		<--Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	473,790		<-- Annual Cost Estimate (A-02)
Total Annual Costs:	$	1,689,008		
Emissions Reduction:		57.8 tpy		
Cost Effectiveness:	**$**	**29,213.50**	**$/ton**	

Belen Unit A-02: Cost Estimate

Total Capital Investment (TCI) =	$ 12,371,394

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$473,790
Indirect Annual Costs (IDAC) =	$1,215,218
Total annual costs (TAC) = DAC + IDAC	$1,689,008

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$61,857	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at 100% full load, ammonia consumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$473,790	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,370
Capital Recovery Costs (CR)=	CRF x TCI =	$1,211,848
Indirect Annual Cost (IDAC) =	AC + CR =	$1,215,218

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,689,008 Per Year
NOx Removed =	57.8 tons/year
Cost Effectiveness =	$29,213.50

El Paso Natural Gas Company, LLC

Caprock Compressor Station - 50 ppmvd NOx based on PTE

Unit: A-01	Interest Rate:		8.53%	<-- EPNG Actual Interest Rate
GE Model M3702R Turbine	Period (yrs):		25	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_X lb/hr:		41.20	lb/hr	<--highest actual test data for GE M3702R-C plus 20% safety factor
NO_X tpy:		180.46	tpy	<-- Calculated using the highest actual test data plus 20% and 8,760 operating hours per year.
SCR				
NO_X Reduction:		70.1%		<-- Reach the 50 ppmc Nox limit
NO_X lb/hr:		12.30	lb/hr	<-- Based on highest test result of GE M3702R-C at equivalent reduction to 50 ppmvd.
NO_X tpy:		53.87	tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	8,180,921		<-- CE2107005 Caprock internal est 07/16/2021 + $1MM per vendor June 2022 letter for 25% cost increase
Total Capital Investment	$	8,180,921		
Annualized TCI:	$	801,367		<-- Based on interest rate, year and TCI
Administrative Costs:	$	3,119		<--Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	452,837		<-- Annual Cost Estimate (A-01)
Total Annual Costs:	$	1,257,324		
Emissions Reduction:		126.6	tpy	
Cost Effectiveness:	**$**	**9,932.88**	**$/ton**	

Caprock Unit A-01: Cost Estimate

Total Capital Investment (TCI) =	$ 8,180,921

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$452,837
Indirect Annual Costs (IDAC) =	$804,486
Total annual costs (TAC) = DAC + IDAC	$1,257,324

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$40,905	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/09/22 quote, at 100% full load, ammonia consumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$452,837	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,119
Capital Recovery Costs (CR)=	CRF x TCI =	$801,367
Indirect Annual Cost (IDAC) =	AC + CR =	$804,486

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,257,324	Per Year
NOx Removed =	126.6	tons/year
Cost Effectiveness =	$9,932.88	

El Paso Natural Gas Company, LLC

Caprock Compressor Station - 50 ppmvd NOx based on PTE

Unit: A-02	Interest Rate:	8.53%	<-- EPNG Actual Interest Rate
GE Model M3572R Turbine	Period (yrs):	25	<-- EPA Air Pollution Control Cost Manual

Base Case

NO_X lb/hr:	20.92	lb/hr	<--highest actual test data for GE M3572R-C plus 20% safety factor
NO_X tpy:	91.61	tpy	<-- Calculated using the highest actual test data plus 20% and 8,760 operating hours per year.

SCR

NO_X Reduction:	63%		<-- Reach the 50 ppmvd NOx limit
NO_X lb/hr:	7.70	lb/hr	<-- Based on highest test result of GE M3572R-C at equivalent reduction to 50 ppmvd.
NO_X tpy:	33.73	tpy	<-- Expected annual NOx emisions (ton/yr) after SCR

Turbine Housing Reconfiguration	$ -		<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$ 12,430,361		<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP) plus $1MM cost increase per vendor
Total Capital Investment	$ 12,430,361		
Annualized TCI:	$ 1,217,624		<-- Based on interest rate, year and TCI
Administrative Costs:	$ 3,374		<--Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$ 474,085		<-- Annual Cost Estimate (A-02)
Total Annual Costs:	$ 1,695,083		
Emissions Reduction:	57.9	tpy	
Cost Effectiveness:	**$ 29,ИУО.ЛУ**	**$/ton**	

Caprock Unit A-02: Cost Estimate

Total Capital Investment (TCI) =	$ 12,430,361

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$474,085
Indirect Annual Costs (IDAC) =	$1,220,998
Total annual costs (TAC) = DAC + IDAC	$1,695,083

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$62,152	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per ArieNox 6/09/22 quote, at 100% full load, ammonia consumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$474,085	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,374
Capital Recovery Costs (CR)=	CRF x TCI =	$1,217,624
Indirect Annual Cost (IDAC) =	AC + CR =	$1,220,998

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,695,083	Per Year
NOx Removed =	57.9	tons/year
Cost Effectiveness =	$29,283.08	

El Paso Natural Gas Company, LLC

Pecos River Compressor Station - 50 ppmv NOx based on PTE

A-01	Interest Rate:		8.53%	<-- EPNG Actual Interest Rate
GE Model M3712R Turbine	Period (yrs):		25	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_X lb/hr:		46.00	lb/hr	<--Highest actual test data for GE M3712R-A plus 20% safety factor
NO_X tpy:		201.48	tpy	<-- Calculated using the highest actual test date plus 20% and 8760 operating hours.
SCR				
NO_X Reduction:		75.5%		<-- Reach the 50 ppmvd NOx limit
NO_X lb/hr:		11.25	lb/hr	<-- Based on highest test result of GE M3712R-A at equivalent reduction to 50 ppmvd.
NO_X tpy:		49.28	tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	8,180,921		<-- CE2107005 Caprock internal est 07/16/2021 + $1 MM (Vendor's June 2022 email indicate cost increase of 25% from the 2021 quote)
Total Capital Investment	$	8,180,921		
Annualized TCI:	$	801,367		<-- Based on interest rate, year and TCI
Administrative Costs:	$	3,119		<--Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	452,837		<-- Annual Cost Estimate (A-01)
Total Annual Costs:	$	1,257,324		
Emissions Reduction:		152.2	tpy	
Cost Effectiveness:	**$**	**8,260.73**	**$/ton**	

Pecos River Unit A-01:Cost Estimate

Total Capital Investment (TCI) =	$ 8,180,921

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$452,837
Indirect Annual Costs (IDAC) =	$804,486
Total annual costs (TAC) = DAC + IDAC	$1,257,324

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$40,905	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at 100% full load, ammonia consumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$452,837	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,119
Capital Recovery Costs (CR)=	CRF x TCI =	$801,367
Indirect Annual Cost (IDAC) =	AC + CR =	$804,486

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,257,324 Per Year
NOx Removed =	152.2 tons/year
Cost Effectiveness =	$8,260.73

El Paso Natural Gas Company, LLC

Pecos River Compressor Station - 50 ppmvd NOx based on PTE

A-02	Interest Rate:		8.53%	
GE Model M3712R Turbine	Period (yrs):		25	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_X lb/hr:		46.00	lb/hr	<--Highest actual test data for GE M3712R-A plus 20% safety factor
NO_X tpy:		201.48	tpy	<-- Calculated using the highest actual test date plus 20% and 8760 operating hours.
SCR				
NO_X Reduction:		75.5%		<-- Reach the 50 ppmvd NOx limit
NO_X lb/hr:		11.25	lb/hr	<-- Based on highest test result of GE M3712R-A at equivalent reduction to 50 ppmvd.
NO_X tpy:		49.28	tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	12,371,394		<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP) + $1 MM cost increase per vendor
Total Capital Investment	$	12,371,394		
Annualized TCI:	$	1,211,848		<-- Based on interest rate, year and TCI
Administrative Costs:	$	3,370		<--Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	473,790		<-- Annual Cost Estimate (A-02)
Total Annual Costs:	$	1,689,008		
Emissions Reduction:		152.2	tpy	
Cost Effectiveness:	**$**	**11,096.93**	**$/ton**	

Pecos River Unit A-02: Cost Estimate

Total Capital Investment (TCI) =	$ 12,371,394

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$473,790
Indirect Annual Costs (IDAC) =	$1,215,218
Total annual costs (TAC) = DAC + IDAC	$1,689,008

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$61,857	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at 100% full load, ammonia consumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$473,790	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,370	
Capital Recovery Costs (CR)=	CRF x TCI =	$1,211,848	
Indirect Annual Cost (IDAC) =	AC + CR =	$1,215,218	

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,689,008 Per Year
NOx Removed =	152.2 tons/year
Cost Effectiveness =	$11,096.93

El Paso Natural Gas Company, LLC

Pecos River Compressor Station - 50 ppmv NOx based on PTE

Unit: A-03	Interest Rate:		8.53%	
GE Model M3712R Turbine	Period (yrs):		25	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_x lb/hr:		46.00	lb/hr	<--Highest actual test data for GE M3712R-A plus 20% safety factor
NO_x tpy:		201.48	tpy	<-- Calculated using the highest actual test date plus 20% and 8760 operating hours.
SCR				
NO_x Reduction:		75.5%		<-- Reach the 50 ppmvd NOx limit
NO_x lb/hr:		11.25	lb/hr	<-- Based on highest test result of GE M3712R-A at equivalent reduction to 5
NO_x tpy:		49.28	tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	12,371,394		<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP+RWIP) + $1MM
Total Capital Investment	$	12,371,394		
Annualized TCI:	$	1,211,848		<-- Based on interest rate, year and TCI
Administrative Costs:	$	3,370		<--Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	473,790		<-- Annual Cost Estimate (A-03)
Total Annual Costs:	$	1,689,008		
Emissions Reduction:		152.2	tpy	
Cost Effectiveness:	**$**	**11,096.93**	**$/ton**	

Pecos River Unit A-03: Cost Estimate

Total Capital Investment (TCI) =	$ 12,371,394

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$473,790
Indirect Annual Costs (IDAC) =	$1,215,218
Total annual costs (TAC) = DAC + IDAC	$1,689,008

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$61,857	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at 100% full load, ammonia consumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$473,790	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,370
Capital Recovery Costs (CR)=	CRF x TCI =	$1,211,848
Indirect Annual Cost (IDAC) =	AC + CR =	$1,215,218

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,689,008	Per YearP
NOx Removed =	152.2	tons/year
Cost Effectiveness =	$11,096.93	

Appendix A-2

Control Cost Estimate Based on Actual Emissions for El Paso Natural Gas Company GE Turbines

El Paso Natural Gas Company, LLC

Afton Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:		3.25%	<-- EPA Default Interest Rate
A-01	Period (yrs):		20	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_X lb/hr:		23.92	lb/hr	<-- July 29, 2020 portable analyzer stack test result (permit limit is 51.26 lb/hr)
NO_X tpy:		14.81	tpy	<-- Calculated 7/29/2020 stack test results and 2011 through 2020 avg actual operating hours.
SCR				
NO_X Reduction:		56.5%		<-- Reach the 50 ppmc Nox from 2020 emissions test
NO_X lb/hr:		10.40	lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_X tpy:		6.44	tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	12,258,524		<-- CE2107005 Caprock internal est 07/16/2021
Total Capital Investment	$	12,258,524		
Annualized TCI:	$	843,128		<-- Based on interest rate, year and TCI
Administrative Charge	$	3,364		
Annual O&M Costs:	$	185,066		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	1,031,557		
Emissions Reduction:		8.4	tpy	
Cost Effectiveness:	**$**	**123,236.19**	**$/ton**	

El Paso Natural Gas Company, LLC

Afton Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:		3.25%	
A-02	Period (yrs):		20	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_x lb/hr:		23.92	lb/hr	<-- July 29, 2020 portable analyzer stack test result (permit limit is 51.26 lb/hr)
NO_x tpy:		3.62	tpy	<-- Calculated 7/29/2020 stack test results and 2011 through 2020 avg actual operating hours.
SCR				
NO_x Reduction:		56.5%		<-- Reach the 50 ppmc Nox from 2020 emissions test
NO_x lb/hr:		10.40	lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		1.58	tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	11,371,394		<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP)
Total Capital Investment	$	11,371,394		
Annualized TCI:	$	782,112		<-- Based on interest rate, year and TCI
Administrative Charge	$	3,310		
Annual O&M Costs:	$	153,309		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	938,731		
Emissions Reduction:		2.0	tpy	
Cost Effectiveness:	**$**	**458,301.93**	**$/ton**	

El Paso Natural Gas Company, LLC

Afton Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:		3.25%	
A-03	Period (yrs):		20	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_x lb/hr:		23.92	lb/hr	<-- July 29, 2020 portable analyzer stack test result (permit limit is 51.26 lb/hr)
NO_x tpy:		37.23	tpy	<-- Calculated 7/29/2020 stack test results and 2011 through 2020 avg actual operating hours.
SCR				
NO_x Reduction:		56.5%		<-- Reach the 50 ppmc Nox from 2020 emissions test
NO_x lb/hr:		10.40	lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		16.19	tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	11,371,394		<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP)
Total Capital Investment	$	11,371,394		
Annualized TCI:	$	782,112		<-- Based on interest rate, year and TCI
Administrative Charge	$	3,310		
Annual O&M Costs:	$	235,383		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	1,020,806		
Emissions Reduction:		21.0	tpy	
Cost Effectiveness:	**$**	**48,516.22**	**$/ton**	

El Paso Natural Gas Company, LLC

Belen Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:		3.25%	<-- EPA Default Interest Rate
A-01	Period (yrs):		20	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_x lb/hr:		15.75	lb/hr	<-- March 30, 2021 portable analyzer stack test result (permit limit is 38.5 lb/hr)
NO_x tpy:		21.60	tpy	<-- Calculated 3/30/2021 stack test results and 2018 through 2020 avg actual operating hours.
SCR				
NO_x Reduction:		56.1%		<-- Reach the 50 ppmc Nox from 2021 emissions test
NO_x lb/hr:		6.91	lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		9.48	tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	12,258,524		<-- CE2107005 Caprock internal est 07/16/2021
Total Capital Investment	$	12,258,524		
Annualized TCI:	$	843,128		<-- Based on interest rate, year and TCI
Administrative Charge	$	3,364		
Annual O&M Costs:	$	229,030		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	1,075,521		
Emissions Reduction:		12.1	tpy	
Cost Effectiveness:	**$**	**88,704.23**	**$/ton**	

El Paso Natural Gas Company, LLC

Belen Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:		3.25%	
A-02	Period (yrs):		20	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_x lb/hr:		15.75	lb/hr	<-- March 30, 2021 portable analyzer stack test result (permit limit is 38.5 lb/hr)
NO_x tpy:		30.47	tpy	
				<-- Calculated 3/30/2021 stack test results and 2018 through 2020 avg actual operating hours.
SCR				
NO_x Reduction:		56%		<-- Reach the 50 ppmc Nox from 2021 emissions test
NO_x lb/hr:		6.91	lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		13.37	tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	11,371,394		<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP)
Total Capital Investment	$	11,371,394		
Annualized TCI:	$	782,112		<-- Based on interest rate, year and TCI
Administrative Charge	$	3,310		
Annual O&M Costs:	$	257,491		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	1,042,913		
Emissions Reduction:		17.1	tpy	
Cost Effectiveness:	**$**	**60,981.61**	**$/ton**	

El Paso Natural Gas Company, LLC

Caprock Compressor Station - 50 ppmc NOx limiting factor

GE Model M3712R Turbine	Interest Rate:		3.25%	<-- EPA Default Interest Rate
A-01	Period (yrs):		20	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_x lb/hr:		34.35	lb/hr	<-- Sept. 29, 2020 portable analyzer stack test result (permit limit is 45.9 lb/hr)
NO_x tpy:		11.51	tpy	
				<-- Calculated 9/29/2020 stack test results and 2018 through 2020 avg actual operating hours.
SCR				
NO_x Reduction:		66.2%		<-- Reach the 50 ppmc Nox limit
NO_x lb/hr:		11.62	lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		3.89	tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	7,180,921		<-- CE2107005 Caprock internal est 07/16/2021
Total Capital Investment	$	7,180,921		
Annualized TCI:	$	493,896		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	118,454		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	612,350		
Emissions Reduction:		7.6	tpy	
Cost Effectiveness:	**$**	**80,398.40**	**$/ton**	

El Paso Natural Gas Company, LLC

Caprock Compressor Station - 50 ppmc NOx limiting factor

GE Model M3712R Turbine	Interest Rate:		3.25%	
A-02	Period (yrs):		20	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_X lb/hr:		16.83	lb/hr	<-- highest most recent test 9/29/2020 portable analyzer
NO_X tpy:		29.64	tpy	<-- Calculated using 2018 through 2020 average actual operating hours and 9/29/2020 results.
SCR				
NO_X Reduction:		56%		<-- Reach the 50 ppmc Nox limit
NO_X lb/hr:		7.38	lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_X tpy:		13.00	tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	11,430,361		<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen R'
Total Capital Investment	$	11,430,361		
Annualized TCI:	$	786,167		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	128,097		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	914,265		
Emissions Reduction:		16.6	tpy	
Cost Effectiveness:	**$**	**54,935.11**	**$/ton**	

El Paso Natural Gas Company, LLC

Pecos River Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:		3.25%	<-- EPA Default Interest Rate
A-01	Period (yrs):		20	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_x lb/hr:		23.46 lb/hr		<-- June 10, 2020 portable analyzer stack test result (permit limit is 53.1 lb/hr)
NO_x tpy:		49.90 tpy		
				<-- Calculated 6/10/2020 stack test results and 2018 through 2020 avg actual operating hours.
SCR				
NO_x Reduction:		53.5%		<-- Reach the 50 ppmc Nox from 2020 emissions test
NO_x lb/hr:		10.90 lb/hr		<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		23.18 tpy		<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	7,180,921		<-- CE2107005 Caprock internal est 07/16/2021
Total Capital Investment	$	7,180,921		
Annualized TCI:	$	493,896		<-- Based on interest rate, year and TCI
Administrative Charge	$	3,059		
Annual O&M Costs:	$	247,776		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	744,730		
Emissions Reduction:		26.7 tpy		
Cost Effectiveness:	**$**	**27,877.28**	**$/ton**	

El Paso Natural Gas Company, LLC

Pecos River Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:		3.25%	
A-02	Period (yrs):		20	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_X lb/hr:		27.34	lb/hr	<-- June 10, 2020 portable analyzer stack test result (permit limit is 53.1 lb/hr)
NO_X tpy:		81.55	tpy	
				<-- Calculated 6/10/2020 stack test results and 2018 through 2020 avg actual operating hours.
SCR				
NO_X Reduction:		60.1%		<-- Reach the 50 ppmc Nox from 2020 emissions test
NO_X lb/hr:		10.90	lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_X tpy:		32.51	tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	11,371,394		<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP)
Total Capital Investment	$	11,371,394		
Annualized TCI:	$	782,112		<-- Based on interest rate, year and TCI
Administrative Charge	$	3,310		
Annual O&M Costs:	$	318,729		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	1,104,151		
Emissions Reduction:		49.0	tpy	
Cost Effectiveness:	**$**	**22,516.97**	**$/ton**	

El Paso Natural Gas Company, LLC

Pecos River Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:		3.25%	
A-03	Period (yrs):		20	<-- EPA Air Pollution Control Cost Manual
Base Case				
NO_X lb/hr:		27.39	lb/hr	<-- June 18, 2020 portable analyzer stack test result (permit limit is 53.1 lb/hr)
NO_X tpy:		67.20	tpy	<-- Calculated 6/18/2020 stack test results and 2018 through 2020 avg actual operating hours.
SCR				
NO_X Reduction:		60.2%		<-- Reach the 50 ppmc Nox from 2020 emissions test
NO_X lb/hr:		10.90	lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_X tpy:		26.74	tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-		<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	11,371,394		<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP)
Total Capital Investment	$	11,371,394		
Annualized TCI:	$	782,112		<-- Based on interest rate, year and TCI
Administrative Charge	$	3,310		
Annual O&M Costs:	$	287,807		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	1,073,229		
Emissions Reduction:		40.5	tpy	
Cost Effectiveness:	**$**	**26,526.85**	**$/ton**	

Appendix A-3

Baker Hughes Letter Dated October 16, 2019 and Provided in the Ozone Precursor Rulemaking as Attachment T to Kinder Morgan's Rebuttal Technical Testimony

T + 1 281-610-1164
11330 Clay Road
Houston, Texas 77041, USA

Baker Hughes

October 16, 2019

SUBJECT: FRAME 3 EMISSIONS TECHNOLOGY FOR AGED MODELS (FR3 A to G)

The first General Electric 2 shaft, Frame size 3 gas turbines were introduced in 1951. The first-generation models were Frame 3 A to G which were manufactured from 1951 to 1966. Emissions abatement technology was not developed for the Frame 3 gas turbines until the 1970's.

Baker Hughes currently does not have an any NOx abatement systems applicable to the Frame 3 A - F machines. Only a preliminary study was performed several years ago on the Frame 3F for LHE liner, no material was manufactured or supplied. We do not have water injection or DLN for the 32F.

There are currently no plans to develop NOx abatement technology for this model machine. It would take significant resources for such a study to take place.

PECOS RIVER 1	Gas turbine unit serial number 95025
PECOS RIVER 2	Gas turbine unit serial number 95053
PECOS RIVER 3	Gas turbine unit serial number 95055

Regards,

Tom Hadden
Senior Sales Manager
Turbomachinery & Process Solutions
Baker Hughes
11330 Clay Road | Houston, TX 77041, USA

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ATTACHMENT 6

Document Summarizing Differences in Cost-Effectiveness Analysis Parameters Between Alternative Emissions Standard Demonstration and Four-Factor Analysis for Pecos River

Assumptions Used in Regional Haze (Four-Factor Analysis) and Ozone Precursor Rules (AES):		
	AES	**4FA**
Interest Rate	Used 8.53% for cost estimates based on PTE and 3.25% for cost estimates based on actual annual emissions	8.53%
Baseline Annual Emissions Lookback Period	For the cost estimate based on actual annual emissions, used the period from 2018-2020	Used the period of 2016-2021 which is consistent with NMED's lookback period
Annual Emission Reduction Rate	Cost estimate based on PTE, Annual Reduction (tpy) = SCR control efficiency % x (highest test results +20% safety factor) lb/hr x 8760 hr/yr	Annual Reduction (tpy) = SCR control efficiency% x avg annual hours (hr/yr) x avg test results (lb/hr)
	Cost estimate based on actual emissions, Annual Reduction (tpy) = SCR control efficiency % x 2020 test results (lb/hr) x average hours (hr/yr)	
SCR Control Efficiency	If based on PTE, SCR control efficiency = [Highest Test Result (ppm) -Rule NOx Limit (50 ppm]/Highest Test Result (ppm)	70%
	If based on actual emissions, SCR control efficiency = [Most Recent Test Result (ppm) -Rule NOx Limit (50 ppm]/Most Recent Test Result (ppm)	
SCR Capital Investment Cost	If based on PTE, SCR capital Investment Cost = CE2107005 Caprock Internal Est 07/16/2021 + $1MM cost increase per vendor 2022 email	CE2107005 Caprock Internal Est 07/16/2021
	If based on actual emissions, SCR capital Investment Cost = CE2107005 Caprock Internal Est 07/16/2021	
Remaining (useful) Life	25	20
Notes	Cost analysis based on the actual emissions are filed from KM's Technical testimony filed on July 28, 2021 before the NM EIB in which the average actual emissions from 2018-2020 were used. In 2022, SCR vendor informed KM that the cost has gone up; therefore, additional $1MM was added to the cost.	
	EPA Cost Control Manual states the useful life is 20-30 year, therefore, used 25 year as useful life in the cost estimate	NMED used 20 years as useful life

ATTACHMENT 7

SCR Cost Analysis and Vendor Capital Quote

KINDER MORGAN

PROJECT NAME	**EPNG NM Ozone Rule - Caprock Compressor Station**		
COMPANY NAME	El Paso Natural Gas Company	**COMPANY NO.**	[redacted]
REQUESTED BY	[redacted]	**PREPARED BY**	[redacted]
ESTIMATE NO.	[redacted]	**ORIGINAL EST. DATE**	07/16/21
REVISION NO.	-	**CONSTRUCTION CONTINGENCY**	5%
REVISION DATE		**OVERHEAD**	0.00%
PROJECT MANAGER	[redacted]	**AFUDC RATE (Debt / Equity)**	Debt: 2.80% / Equity: 7.23%
STATE	New Mexico	**TAX GROSS UP**	0.00%
COUNTY	Lea	**PROJECT TYPE**	Sustaining Capital
		IN-SERVICE	Aug-23

Reservation Credits SCOPE:	Potential 2022 reservation credits on the XOver with one Caprock unit unavailable. Assumes three (3) months outage for SCR and Regen modifications per unit (6 months total).
CWIP- Unit 1 Emissions Controls SCOPE:	Install SCR Emissions control system provided by [redacted] New expansion joints (3 per unit) will be installed on ducting between new regen and new SCR. Install a new Aux building for a new air system and other SCR controls.
CWIP-Unit 1 Regen SCOPE:	Install a new Regeneration equipment on Unit 1. Estimate includes a PAL-CON purchase credit for a multiple unit purchase.
RWIP-Unit 1 Regen SCOPE:	Remove the existing regenerator on Unit 1 including all exhaust duct work from the first Turbine Exhaust Expansion Joint to the entire exhaust stack. Prep site for installation of new regen unit.
CWIP- Unit 2 Emissions Controls SCOPE:	Install SCR Emissions control system provided by [redacted] New expansion joints (3 per unit) will be installed but the existing exhaust stack will be reused. Install a new Aux building for a new air system and SCR controls.
CWIP-Unit 2 Regen SCOPE:	Install a new Regeneration equipment on Unit 2.
RWIP-Unit 2 Regen SCOPE:	Remove the existing regenerator on Unit 2 including all exhaust duct work from the first Turbine Exhaust Expansion Joint to the entire exhaust stack. Prep site for installation of new regen unit.

ASSET CAPABILITIES: Vol @ ### psi

Minimum	MMCFD
Maximum	MMCFD

	Pressure
Minimum	psig
MAOP	psig
Normal Operating	psig
Delivery Pressure	psig

ESTIMATE SUMMARY	Reservation Credits	CWIP- Unit 1 Emissions Controls	CWIP-Unit 1 Regen	RWIP-Unit 1 Regen	CWIP- Unit 2 Emissions Controls	CWIP-Unit 2 Regen	RWIP-Unit 2 Regen	TOTAL
MATERIAL (INCL SALES TAX)	$ -	$ 4,310,500	$ 3,403,800	$ -	$ 3,639,700	$ 3,512,700	$ -	$ 14,866,700
COMPANY LABOR COST	$ -	$ 37,100	$ -	$ -	$ 37,100	$ -	$ -	$ 74,200
PM, ENG, LAND, ENVIRO - EXPENSE	$ -	$ 3,100	$ -	$ -	$ 3,100	$ -	$ -	$ 6,200
PRIMARY CONSTRUCTION CONTRACTOR	$ -	$ 1,916,500	$ 670,500	$ 449,000	$ 1,798,100	$ 670,500	$ 449,000	$ 5,953,600
SECONDARY CONTRACTOR	$ -	$ 182,900	$ -	$ -	$ 166,900	$ -	$ -	$ 349,800
PROFESSIONAL ENGINEERING	$ -	$ 49,500	$ -	$ -	$ 49,500	$ -	$ -	$ 99,000
INSPECTION SERVICES	$ -	$ 148,400	$ 101,300	$ 36,100	$ 148,400	$ 101,300	$ 36,100	$ 571,600
RADIOGRAPHY SERVICES	$ -	$ 900	$ -	$ -	$ 900	$ -	$ -	$ 1,800
ENVIRONMENTAL CONTRACTOR	$ -	$ 16,100	$ -	$ -	$ -	$ -	$ -	$ 16,100
ELECTRICAL & INSTRUMENTATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIGHT OF WAY CONTRACTOR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SURVEY CONTRACTOR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OUTSIDE LEGAL SERVICES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ROW & DAMAGES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PERMIT FEES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GAS LOSS	$ 1,620,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,620,000
SUBTOTAL	$ 1,620,000	$ 6,665,000	$ 4,175,600	$ 485,100	$ 5,843,700	$ 4,284,500	$ 485,100	$ 23,559,000
CONSTRUCTION CONTINGENCY	$ 81,000	$ 333,250	$ 208,780	$ 24,255	$ 292,185	$ 214,225	$ 24,255	$ 1,177,950
AFUDC	$ 9,130	$ 182,671	$ 124,900	$ -	$ 157,906	$ 128,490	$ -	$ 603,098
SUBTOTAL	$ 1,710,130	$ 7,180,921	$ 4,509,280	$ 509,355	$ 6,293,791	$ 4,627,215	$ 509,355	$ 25,340,048
CAPITALIZED OVERHEAD (BURDEN)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TAX GROSS-UP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ESCALATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RISK INSURANCE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ESTIMATED TOTAL COST	**$ 1,710,130**	**$ 7,180,921**	**$ 4,509,280**	**$ 509,355**	**$ 6,293,791**	**$ 4,627,215**	**$ 509,355**	**$ 25,340,048**
Price/Ton:	$2,400							
(If Applicable) Escalated Price/Ton:								
Contingency:	5%	5%	5%	5%	5%	5%	5%	
In-Service Date:	Aug-23	Aug-23	Aug-23	Aug-23	Aug-23	Aug-23	Aug-23	

ASSUMPTIONS

Include (Yes/No)	Assumptions	
Yes	See Assumptions Tab	** Estimate shelf life is 6 months from published date.

Revision	Date	Notes	Approval	Name	Date
			Project Manager	[redacted]	
			roject Manager Direct	[redacted]	
			Project Controls	[redacted]	
			Vice President	[redacted]	

[redacted]

Escalation Rates $FV=PV(1+i)^n$	
Material:	0.0%
Other:	0.0%

Estimate Form Revision 10.3-Medium 05/26/21

[redacted]

Kinder Morgan

Proposal Title: Caprock

Proposal Number: [redacted]

Proposal Description: [redacted] Emission Control System to Reduce Emissions from (2) GE Frame 3 Turbines

Submitted by: [redacted]

[redacted] **Contact:** [redacted]

Date Submitted: July 8, 2021

[redacted]

July 8, 2021

Kinder Morgan
James Trent
1001 Louisiana Street
Houston, TC 77002
Phone: 713-254-5279
Email: james_trent@kindermorgan.com

[redacted]	[redacted]
Project Name:	**Caprock**

James,

We are pleased to submit this REVISED BUDGETARY proposal for [redacted] **Control System** designed to reduce emissions for (2) Frame 3 Turbines.

Rev 1 – Added oxidation catalyst increased sized for lower NOx in the future, option for jib crane and unloading pump station. Housing designed to support future NOx guarantee to 10ppm @15%O2. Elements designed in this quote for 50ppm @15%O2.

The [redacted] **Emissions Control System** offered for this project is based on engine and emissions data provided by Kinder Morgan. The enclosed proposal details the price, scope of supply, warranty, commissioning and terms and conditions necessary to achieve the required emissions limits and long-term compliance.

Should you have any questions or comments, please do not hesitate to contact me.

[redacted]

[redacted] COMPLIANCE AT A COMPETITIVE COST

[redacted] is an environmental engineering company supplying reliable exhaust after-treatment based emissions control systems to the North American market. Our strength is helping customers comply with federal and local emission regulations targeting process machines, marine vessels, offshore rigs, stationary diesel and natural gas engines and turbines. We specialize in reducing NOx using a comprehensive systems approach based on Selective Catalytic Reduction (SCR). Our SCR systems are then combined with oxidation catalysts or particulate filter technologies to reduce other regulated pollutant emissions, such as carbon monoxide (CO), hydrocarbons (HC), volatile organic compounds (VOC) and particulate matter (PM). We also offer an array of supporting component options, from urea storage tanks to air compressors to silencers, with the goal of providing everything necessary for a successful and near-turnkey installation.

[redacted] leverages more than five decades of experience in environmental compliance, and draws upon the knowledge of over 1000 successful SCR systems in a wide variety of markets such as marine, power generation, oil and gas development, industrial and chemical processes.

Our structured engineering approach begins by comparing your project's emissions profile to the regulations, or to the project's unique requirements. We then design an emission control system tailored to your application. Our product manufacturing process is governed by exacting quality standards, and our systems are commissioned with the [redacted] Emissions Guarantee. To ensure compliance over the long-term, we provide support after the sale through extensive operator training, spare parts, and on-site maintenance.

[redacted] is simply defined as being your trusted partner, helping you comply with federal and local regulations with emission control systems that are:

- ***Proven***
- ***Reliable***
- ***Cost-Competitive***

In the proposal you will find the [redacted] Emissions Control System and Commissioning details in the Scope of Supply. We can also provide several optional components necessary for a comprehensive installation, such as a urea storage tank, silencer or air compressor. Our goal is to also provide the convenience of having all components necessary for a successful installation available from a single source.

Thank you for the opportunity to provide this proposal. Should you place an order with us, we can assure you seamless integration with your project management team, and exceptional quality of the delivered emissions control system, accompanying documentation, and post-installation parts and service support.

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[redacted]

[redacted]

I. QUOTATION

PROPOSAL #: [redacted]

PROJECT: Caprock

DESCRIPTION: [redacted] Emission Control Systems to reduce emissions from GE Frame 3 Natural-Gas Fired Turbines

1. SCOPE OF SUPPLY

ITEM	DESCRIPTION	EXT. PRICE ($)

001	**EMISSIONS CONTROL SYSTEM (2 x Frame3)**
	• 2 x Ducting / SCR Housing / Silencer
	  ○ Oxidation Catalyst
	  ○ Ammonia Injection Grid
	  ○ SCR Catalyst
	  ○ Ducting from Regen Outlet to SCR
	  ○ Expansion joint at Regen Outlet
	  ○ Ducting from SCR to Tailpipe
	  ○ Silencer / Tailpipe with CEMS Ports
	• 2 x Recycle Gas Skid, each including:
	  ○ 1 x Two-Phase Injection Lance for ammonia/air
	  ○ 1 x Static mixer
	  ○ 1 x Ventilator fan
	• 1 x SCR Control System with Touch-screen and PLC
	  ○ With NO/O2 analyzer (dual channel, single O2 measurement)
	  ○ 2 x Sample Probes and Heated Sample Lines (Per Unit)
	• 2 x Ammonia/Air Dosing Panel
	• 1 x Reagent Pump Station
	• 1 x Reagent Storage Tank
	• Engineering, Operation & Maintenance Documentation (Thumb Drive Only)
		$6,200,000

002	**COMMISSIONING and TRAINING (2 x Units)** Estimated 12 man-days, per engine for the commissioning of the emission control system to meet the required emissions levels, plus 1 day of on-site training; includes costs of travel and accommodations. We can provide qualified personnel to supervise installation at the rate of $1,350 per man-day, plus travel expenses. Additional time will be billed per the time and material rates.	**$50,000**
003	**INSTALLATION ASSISTANCE (2 x Units)** Estimated 90 man-days for both units to assist with construction supervisions of the hardware included herein. All labor/expenses will be billed per a time and material rate of $1,350 per man-day, plus all travel expenses.	**$175,000**

Not included in the scope of supply:

- Load signal from the engine (4-20 mA)
- Fuel flow signal from the engine (4-20mA)
- Fuel composition (TCP/IP)
- Engine running signal (digital dry contact, closed when engine is running)
- Internet connection for remote PLC access and service support
- Structural and civil work necessary to complete the installation
- Catalyst element lift / crane (available as an option)
- Aqueous Ammonia Solution
- Unloading valve/pump skid and controller (available as an option)
- Platforms and other support structures not listed herein
- Compressed Air, per ISO 1.3.4 requirements
- Heat tracing of Ammonia tank or Ammonia lines (available as an option)
- Provision for electricity and connection of the power supply to the enclosure
- System integration (design and engineering) with the building structure
- Unloading of material at customer location
- Any 3rd party emission certification of stack test

OPTIONAL HARDWARE and SERVICES

ITEM	DESCRIPTION	EXT. PRICE ($)
4.1	**JIB REMOVAL CRANE (OPTIONAL, 2 UNITS)**	**$68,650**
4.2	**UNLOADING PUMP STATION (OPTIONAL, PER SITE)**	**$53,800**
4.3	**SCR ELEMENTS (OPTIONAL, PER UNIT)**	**$200,000**
4.4	**OXIDATION ELEMENTS (OPTIONAL, PER UNIT)**	**$145,000**

2. PRICE

The given prices for the SCR Emissions Control System are net prices, DDP to customer location in NM, according to Incoterms 2010. All prices are in US dollars. Not included are taxes. Shipping based on standard ground, sea vessel and non-expedited shipping.

3. PAYMENT

30% of the order value upon initial order;
15% of the order value with submittal of engineering documents
50% of the order value with ready for shipment of the hardware
5% of the order value after successful commissioning, not to exceed six (6) months after delivery
All payments are to be paid within 30 days after each date of invoice, net.

4. SCHEDULING & DELIVERY

Delivery of the drawings and technical documents is approximately 16 weeks after receipt of a purchase order. Delivery of the hardware is approximately 32 weeks after approval of all technical details. Total estimated schedule (with a 4-week customer review period) is 36 weeks for receipt of material at each station.

- Preliminary Engineering Drawings – Approximately 16 weeks after receipt of a purchase order
- Customer Review/Approval – 4 Weeks from Receipt of Preliminary
- Release IFC's – 4 Weeks From Receipt of Customer Comments
- Manufacturing – 26-30 Weeks From Customer Approval
- Shipping – 3-4 Weeks
- Total Estimated Time For 2 Units: ~56 Weeks (Accelerated Schedule Available At Additional Cost). Follow on unit likely at 2-3 month intervals

5. QUALITY STANDARD

All drawings will be in both metric and English units. We reserve the right to adapt the technical design of the emission control system based on the results of the final engineering work, provided this does not impact the affect the guaranteed performance characteristics and is approved by the customer before production begins.

6. OFFER VALIDITY

This offer is valid 90 days from date on proposal.

II. TECHNICAL DESCRIPTION

1. EXHAUST GAS DATA & EMISSION REQUIREMENTS

Unit Data:

Parameter = 100% Load	Unit	GE Frame 3*
Fuel	-	CQNG
Power	bhp	7,040
Exhaust Gas Flow Rate (wet)	lb/hr	~335,000
Exhaust Gas Moisture Content (actual, wet)	Vol. %	3.5
Oxygen Content (actual, wet)	Vol. %	18.1
Exhaust Temperature	°F	450**

** From KM provided data*
***Regen Outlet*

Emission Control System Design Parameters:

Parameter	Unit	Frame 3
Aqueous Ammonia Solution	%	19
Aqueous Urea Solution Consumption Rate (at 100% engine load) approximately, per engine	gph	~10.0
Total Estimated Backpressure Contribution	inH_2O	9.0
Air Consumption, per engine (Based on 87 psi nominal, max 160 psi	scfm	25**

**Based on worst case: Max exhaust flow, 150ppmvd@15%O2 NOx inlet and ~30ppmvd @15% O2 NOx outlet. Reduced loads and lower NOx inlet will yield lower aqueous reagent consumption rates*

***Type Z purge for control panel and dosing panel are not included in this air consumption*

Electrical Load:

Load	VAC	Watts
SCR Panel (Per Unit) Distributes: 480VAC to pump and blower 110VAC to tank distribution panel 24VDC to dosing panel and pump panel	480VAC, 3Ph	~50Watts

2. EMISSIONS GUARANTEE & WARRANTY

Constituent	Current Engine Out	Required Stack Out**
NOx as NO_2*	150 ppmvd @15% O_2	50 ppmvd @15% O_2
CO*	35 ppmvd @15% O_2	15 ppmvd @15% O_2
VOC*	20 ppmvd @15% O_2	9 ppmvd @15% O_2

** Based on 1 hour averaging with the engine operating at 100% load. Minimum temperature for SCR performance is 570F.*

***Based on a minimum 440F SCR outlet temperature with 19% NH3 and Maximum SCR inlet temperature of 750F*

Provided the engine is operating under stable operating conditions, [redacted] guarantees the stack emissions (Based on % reduction) for a period of 24,000 hours of operation or 36 months after the initial SCR commissioning, or 42 months after delivery, whichever comes first. All values are per EPA-approved measurement methods, with one-hour averaging while the engine is operating at 100% load. The mechanical warranty is 12 months after commissioning or 18 months after delivery, whichever comes first.

This guarantee is subject certain maintenance practices and engine operating conditions, [redacted] The guarantee is also based on the emissions data provided to [redacted] at the time of this quotation and defined in Section 1 of the Technical Description. [redacted] reserves the right to modify Items 001 in the Scope of Supply and associated price once more accurate and complete emissions data are obtained in order to ensure the emission limits can be maintained as required.

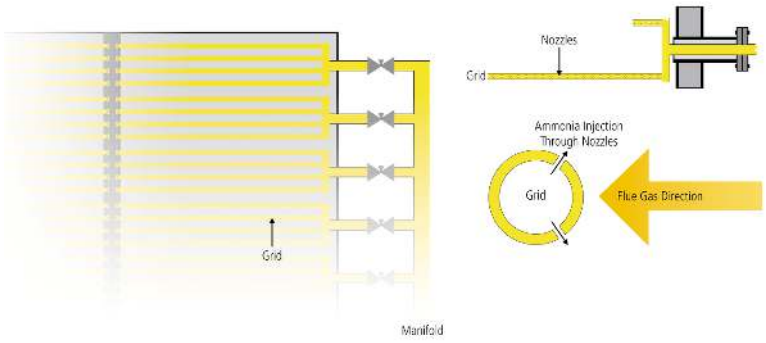
3. SCOPE OF SUPPLY

A. Engineering (Per Site)

- Project Management
  - Includes monthly conference calls and documented updates with action items
  - Manage change order process and site activity
  - Accounting and Invoicing
- 2 Engineering Meetings at Customer site, maximum 1 day on-site per trip
- Drawings
  - Ducting drawings including structure supports necessary for construction
  - Silencer and Tailpipe construction drawings
  - Recycle gas skid mechanical
  - SCR / OXI catalyst arrangement
- System flow diagram
  - P&I diagram for the process and the auxiliaries
  - Flow Diagram
- Control of the SCR system
  - Software and operational description for control of the SCR-system
  - Cable diagram
  - Instrument list
- Documentation
  - Installation instructions including check lists for mounting and structural work (at 'Ready to Ship' for structure/ducting)
  - SCR and OXI Element operation and maintenance manual (post commissioning)
- Supporting Analyses
  - Ducting/Silencer structural design and calculations related to geographic requirements (i.e. wind, seismic)
  - CFD modeling as required to support AIG design

B. Ammonia Injection Grid (Per Unit)

Includes one ammonia injection grid (AIG). The ammonia gas will be re-injected in the main exhaust gas duct with an ammonia injection grid. Each turbine will include (1) NH3 monitor with visual and audible indication.



Ammonia Injection Grid

- Piping with injection Nozzles
- Header
- Isolation and dosing valve

AIG Design figures:

- Material: Stainless Steel
- Flanges: ANSI

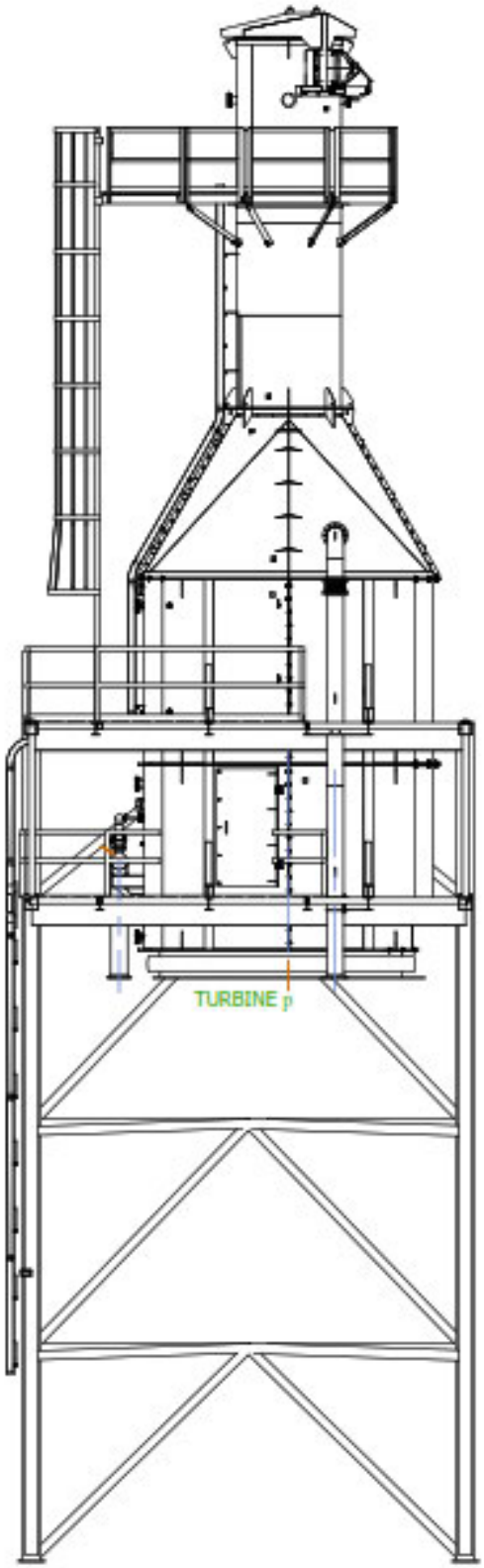


C. OXI / SCR Reactor Housing / Ducting / Silencer (Per Unit)

The reactor housing duct and stack is designed as a cool wall lined system. This design incorporates a high strength carbon steel casing complete with external structural stiffening and support steel with an internal floating liner decoupled from the casing using a proprietary liner isolation support system. Compressed thermal / acoustical insulation between the 409SS liner and casing reduce thermal and acoustic coupling between the two surfaces minimizing the transfer of heat and noise to outer surfaces of the duct system. Ducting/structure consists of the following major components:

- Inlet expansion joint, multi-layered composite belt style. Rated at 1100F +/- 2psig
- Acoustically and thermally lined inlet transition duct
- SCR reactor housing designed for AIG, SCR and Oxicat elements. Includes (2) personnel access doors for catalyst maintenance and replacement (Oxicat and SCR)
- Exhaust stack to include silencer section and (4) EPA approved flanged test ports. Acoustic design is based on 85 dBA @ 3ft perpendicular to stack exit, 100 mph wind load.
- Stack height from grade is 85ft with ~6ft inside diameter
- Includes all flanged joint hardware (bolts, nuts, washers and gasket material)
- Liner kits to include liner material, bolting for internal flanges will be supplied as needed
- Includes static rain cap to protect SCR elements from water damage
- Maintenance platform for installation and removal of the oxidation and SCR modules. Ladders will be compliant to the latest OSHA standards (Fall restraints per OSHA 1910.28)

CONSTRUCTION:
Baffles: 14 GA 409 SS Insulation: High temp mineral wool with SS erosion protection
TRANSITION / SILENCER / DUCT:
Casing: Continuously welded A-36 carbon steel Flanges/Stiffs: A-36 carbon steel Insulation: High temp mineral wool with SS erosion protection Liner: 12 GA 409 SS solid and 14 GA 409 SS Perf Exterior Only: SSPC-SP6 commercial blast Coating: (1) Coat zinc primer (2-3 mils DFT) (1) Coat Amercoat 741 (2-3 mils DFT)
LADDERS/PLATFORM:
Structure: Continuously welded A-36 carbon steel Coating: Hot dipped galvanized



Representative Layout

D. SCR Catalyst (Per Unit)

The SCR catalyst is a corrugated monolith catalyst. The elements will be designed for installation within the framework of the ducting. Individually loaded in the SCR housing.

Type of Catalyst:	Honeycomb
Approximate Element Weight:	~12,000 lbs (~78 lbs each)
Catalyst Layers Per Housing:	2
Approximate Internal Reactor Cross-Section Dimensions: (W x H)	12.5 ft x 13.5 ft

Note the SCR catalyst impurity tolerance specification in Section IV and SCR manufacturer data sheet.

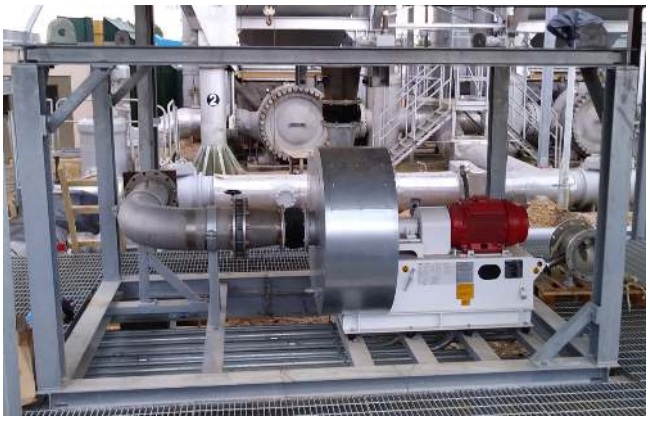
E. Recycle Gas Skid (Per Unit)

A small part of the exhaust gas will be taken out from the main exhaust gas duct downstream of the SCR reactor housing and sent to the recycle gas skid, where aqueous ammonia solution will be injected, evaporated and re-injected in the main exhaust gas duct via the ammonia injection grid. For a defined exhaust gas flow.

Blower Skid

Skid including:

- 1 x Blower, rated at ~11 kW, 480VAC, 3 Ph
- 1 x Steel Duct,
  - Diameter 10 in
  - Exhaust piping: SS304



Mixing Duct With Gas Mixer (2 Phase)

- 1 x Static mixer, Design features:
  - Flanges: ANSI 10 in
  - Mixer Type: Cross-impulse-mixer
  - Material disc: Stainless steel
  - One piece of air atomization nozzle integrated in the mixer

F. SCR Control (Per 2 Units)

The SCR unit is controlled by a single control system housed in a control cabinet. Includes an Allen-Bradley ControlLogix Programmable Logic Controller and an A-B 15in touch screen with menu-guided parameter inputs (without any program change); password protection; error message and clear readable display. Includes an Ethernet communication between the PLC and the customer's control system. SCR Control Panel will include a (2) day FAT to test and review PLC, IO, communications, power and HMI screens. Customer witness / approval is required before shipping.



- Operating hour indication
- (3) temperature measurements with thermocouples
- Pressure measurement (delta P over the SCR catalyst)
- Flow measurement for reducing agent with limit switch
- NO/O2 Analyzer (Per Turbine) for pre and post SCR measurement
  - Includes necessary gas conditioning
  - Includes <120ft sample line and probe
- Power: 480V, 60Hz, 3 Ph

NOTE: Designed for indoor installation. 5F to 95F Temperature range
NOTE: Approximate Cabinet Dimensions: 83 in x 71 in x 24 in (H x W x D)
NOTE: Panel will require Type Z Purge to meet Class, Div 2 Requirements. Option available for Class 1, Division 2 Building to house SCR control panel with gas analytics
NOTE: Based on Rosemount T/C based temp transmitters and DP pressure transmitters. DP transmitter to include 5-valve manifold for calibration
NOTE: [redacted] can support different PLC/HMI manufacturer(s) at the request of the customer. This will likely result in additional cost and time.
NOTE: NEMA 4 enclosure, painted standard manufacturer grey, ambient temperature 40-110F

G. Reagent Dosing Panel (Per Unit)

All components for aqueous ammonia dosing are mounted on a steel back panel; includes steel dosing valve, magnetic valves and shut-off valves. (Pressure indicators related to reagent solution supply to the dosing panel are the customer's scope.) Designed for indoor installation, NEMA 4x panel with Type Z purge. Ambient temperature range: 40-110F



Protection:	Suitable for Class 1, Division 2
Dimensions	24 in H x 24 in W
Connections: Reagent Solution: Atomizing Air:	 Panel connection with 3/8in Swagelok fitting Panel connection with 3/4in Swagelok fitting

NOTE: Panel to be <35 ft from injector
NOTE: Based on E&H or IFM Flow Meter, Burkert Control Valves, IFM pressure Sensor. No calibration manifolds included with the dosing valve components.

H. Ammonia Pump Station (Per Site)



Pump station complete with auxiliary valves, filters; ships fully assembled and pretested from our factory. The pump station has been designed for 19% aqueous NH3 for simultaneous operation of all units at the facility. The pump station also comes with one 100% backup pump. NEMA standard protection with VFD's installed on skid. Designed for indoor installation. Power to pump station direct from customer MCC. 480VAC/3Ph/1.5kW per pump. NEMA4x electrical enclosure. Panel designed for ambient range: 40-100F

NOTE: Based on IFM pressure Sensor. No calibration manifold provided.

NOTE: Suitable for outdoor in non-hazardous location. Located next to reagent storage tank

I. Ammonia Tank and End Devices (Per Site)

Includes (1) horizontal, 25,000 USG, single-wall stainless-steel tank. 120in D x 42ft tangent to tangent length, made of 304 stainless steel, built to ASME Section VIII Division 1 Code, Design Parameters: 30 psig, 125˚F with 1/16 in corrosion allowance. Tank includes:

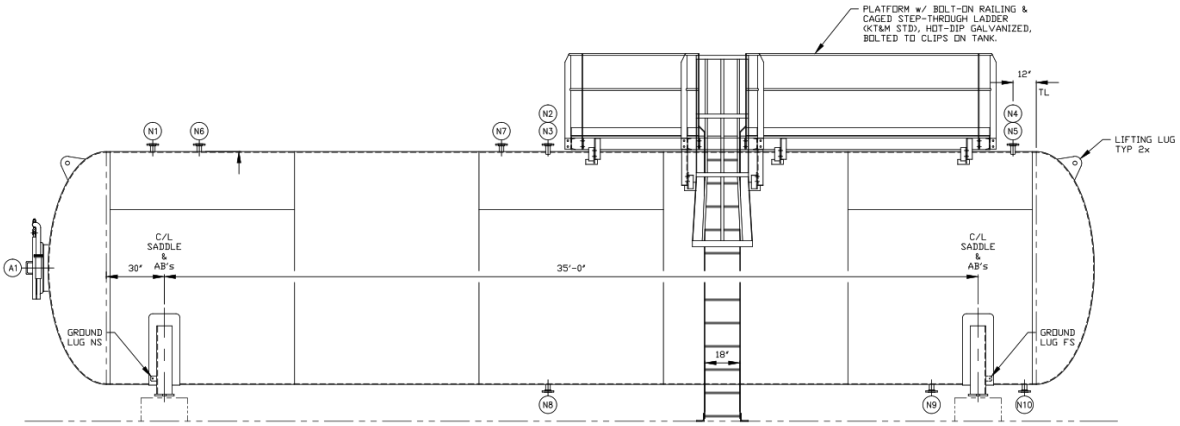
- 24 in ASME Manway
- (8) 2in FNPT fittings
- (2) 4in FNPT fittings
- (2) Lift lugs
- (1) Ground lug



With the following end devices: (Shipped Loose)

- (1) Ultrasonic level transmitter
- (1) Temperature transmitter
- (1) Pressure transmitter
- (1) Relief and Vacuum Valve
- (1) NH_3 leak detection sensor
- (1) Control panel for indication of level, pressure and temperature

NOTE: Suitable for outdoor installation in non-hazardous location. Distribution panel Located next to ammonia storage tank. Option available to add an unloading pump station to the control panel and ammonia storage tank at the request of the customer



Representative Tank Arrangement

III. OPERATING PRINCIPLE

Selective Catalytic Reduction Principle

NOx is a general term referring to Nitrogen Oxide (NO) and Nitrogen Dioxide (NO_2) gases. NOx forms at the high temperatures of a combustion process, typical of internal combustion engines. NOx is a precursor to smog and adversely effects health and the environment. As such, NOx is increasingly regulated by both the US Environmental Protection Agency and by local authorities.

NOx emissions are most efficiently removed from the exhaust by Selective Catalytic Reduction, often referred to as SCR. SCR works by promoting a chemical reaction between the NOx and ammonia gas (NH_3), which is introduced upstream of the SCR catalysts. The ammonia can come from a variety of sources, including directly as a gas (known as anhydrous ammonia), or as an aqueous ammonia solution. It is more common to use aqueous urea solution. Urea is a widespread component of fertilizer, and water-based solutions made from urea are easier to handle than ammonia compounds. Moreover, aqueous urea solutions are readily available in different storage capacities and concentrations.

Commercially, aqueous urea solutions come in two concentrations, either 32.5% or 40%. The lower concentration, 32.5%, has the lowest freezing point of 12°F (-11°C), and is therefore used in colder climates where ambient temperatures can reach this point. The 40% concentration has a higher freezing temperature of 35°F (2°C), but requires less volume of solution to achieve the same degree of NOx reduction. In either case, freezing is to be avoided since injection becomes problematic. When low temperatures are encountered in the application, it is customary to install an immersion heater in the urea storage tank, as well as heat-tracing the urea supply lines to the SCR System. This is true for both concentrations of urea solution.

When the engine is running and the catalyst has warmed up to its normal operating temperature, urea solution is injected into exhaust stream ahead of the SCR catalyst, in combination with high-pressure air, to assist in atomizing the spray. (The air also cools the urea injection nozzle and purges the injector when the engine is no longer running.) Chemically, the heat of the exhaust first vaporizes the water in the urea solution, resulting in the formation of small urea crystals. These crystals further breakdown in the exhaust stream into ammonia and carbon dioxide. Once ammonia is present, the chemical reactions shown below take place over the SCR catalyst, reducing NOx to harmless nitrogen gas and water vapor.

Once ammonia gas is present, the chemical reactions shown below take place over the SCR catalyst, reducing NOx to harmless nitrogen gas and water vapor:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O$$
$$2\ NO + 2NO_2 + 4\ NH_3 \rightarrow 4\ N_2 + 6\ H_2O$$

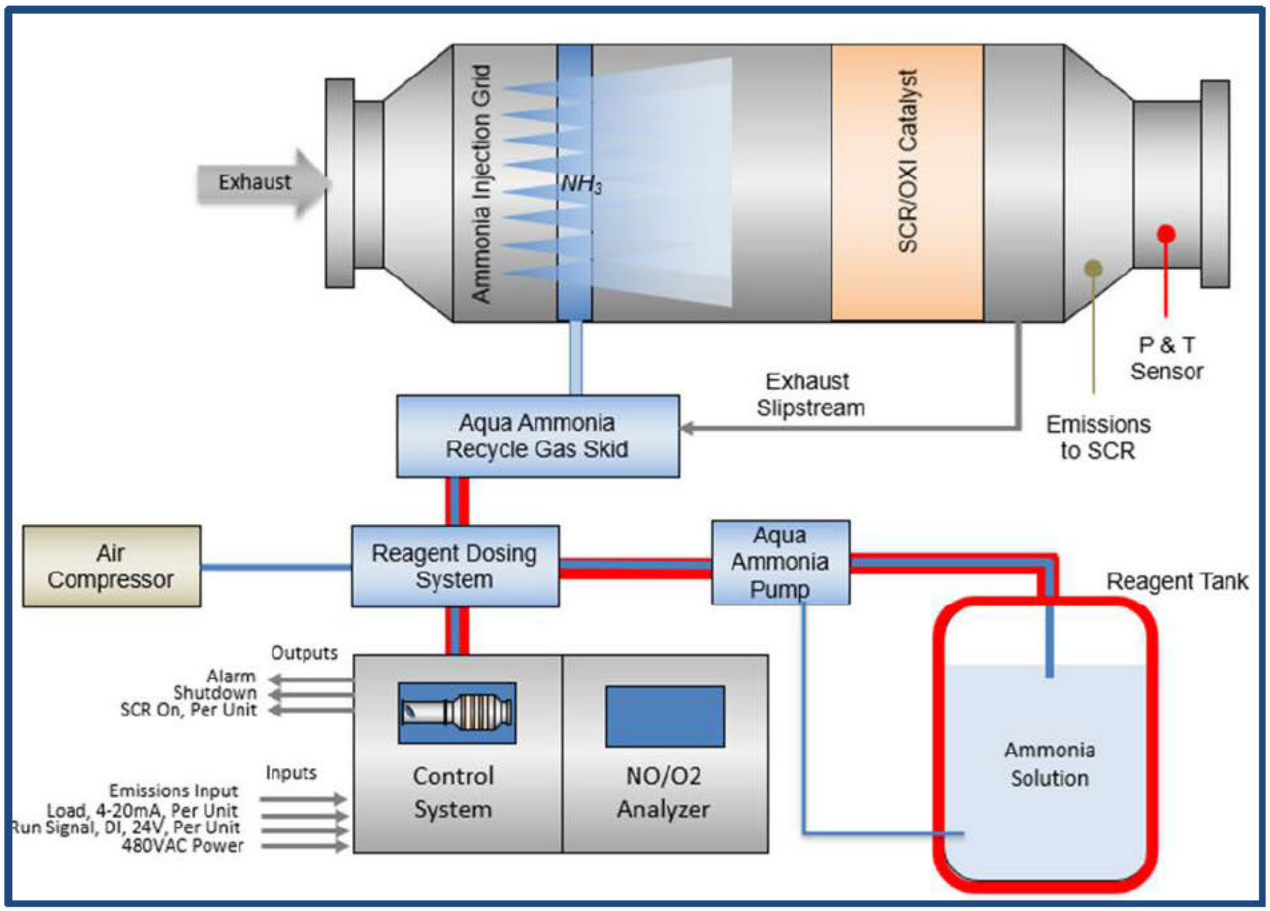
The SCR Catalyst Technology:

SCR catalysts generally fall into two categories, a vanadia-based catalyst embedded in an extruded ceramic substrate, or a zeolite-based technology coated onto the surface of a ceramic substrate. In the former, the catalyst is actually incorporated into the ceramic structure, and as a result the catalyst is generally more robust to thermal variation. In addition, vanadia-based technologies operate over a wide temperature range, and when combined with its strength advantages and lower cost, are used in many

industrial applications such as large-scale power plants and boiler systems. Vanadia-based catalysts have demonstrated NOx reduction capability of up to 98%, and can operate continuously to temperatures of 510°C (950°F).

Zeolite systems are ideal for higher temperature applications, for example above 510°C, and as such have found wide use in mobile diesel applications such as on-highway trucks. These systems have also demonstrated a capability for high NOx reduction.

The size of the SCR catalyst elements and how they are configured in a catalyst housing (e.g., number of catalyst layers) is determined by factors such as the required NOx reduction, allowable back pressure of the engine, and ammonia slip limits. High levels of NOx reduction (>80%) generally require 2-4 layers of catalyst.



Schematic of a representative [redacted] Emission Control System.

Urea Injection Strategy:

Reducing NOx to N_2 with high levels of chemical conversion efficiency without introducing excess ammonia into the exhaust (known as "ammonia slip") requires precise control of the urea or ammonia injection process. The strategy for urea or ammonia injection depends on the degree of NOx reduction, and the required ammonia slip limits.

The simplest injection strategy links the engine to the SCR system through the engine load. NOx emissions are measured as a function of engine load, creating a "NOx vs. Engine Load" map. From this map, an injection algorithm determines the amount of urea or aqua ammonia necessary to reach the required NOx level, and sends this signal to the dosing control system. Because the amount of urea or ammonia injected is based on the engine load and not on a direct measurement of NOx, such an engine mapping strategy is often referred to as an "open-loop" control strategy. Such an injection strategy has been used successfully when NOx reduction requirements are generally less than 90%. Moreover, the strategy has demonstrated that ammonia slip is minimal, generally far less than typical 10ppm regulatory requirements.

When higher levels of NOx reduction are necessary, it is customary to add a NOx analyzer to the SCR System to directly measure NOx after the SCR catalyst. The signal from the analyzer is then sent to the SCR dosing control system, which then "trims" the injection volume up or down to ensure the required NOx reduction level is reached, without overdosing that could lead to an increase in ammonia slip. As the NOx is measured directly with the NOx analyzer, and the signal is used to control the reagent dosing volume, this strategy is referred to as "closed-loop" control. This strategy has demonstrated up to 98% NOx reduction, with very low levels of ammonia slip (as low as 5ppm in some applications).

Role of the Oxidation Catalyst:

By incorporating an oxidation catalyst into the system, it is possible to reduce carbon monoxide (CO), many hydrocarbon species (HC), volatile organic compounds (VOC) such as formaldehyde, and particulate matter. Placement of the oxidation catalyst depends on the application requirements, such as degree of CO reduction, but also on parameters such as the degree of NOx reduction and maximum levels of ammonia slip. In many cases, the oxidation catalyst can be incorporated directly into the SCR catalyst housing, saving both space and the cost of a separate housing.

Oxidation catalysts are generally precious metals-based systems composed of platinum, or mixtures of platinum, palladium and other precious group metals (PGM). PGM catalysts are highly effective at utilizing the excess oxygen in the exhaust stream of lean-burning engines to convert CO, HC and formaldehyde to water vapor and carbon dioxide, as shown below:

$$2CO + O_2 \rightarrow 2\ CO_2$$
$$HC^* + O_2 \rightarrow H_2O + CO_2$$
$$HCOH + O_2 \rightarrow H_2O + CO_2$$

Oxidation catalysts can be engineered to operate at temperatures similar to SCR catalysts, allowing for reduction of several pollutant emissions within the same system. Moreover, oxidation catalysts are highly effective, reducing emissions as much as 95%.

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* *The specific reaction depends on HC species, such as CH_4, C_2H_6 etc.*

IV. SCR CATALYST IMPURITY TOLERANCE SPECIFICATION

SCR catalysts, like all catalyst materials, are susceptible to severe performance degradation if certain impurities in the exhaust stream exceed specific levels. These impurities derive from the use of improper or off-spec fuels, certain impurities in landfill or digester gases, lubrication oils, or other additives that could become part of the exhaust gas composition.

In order to maintain the warranty for the SCR quoted in this engineering document, the following impurities and impurity concentrations must be strictly adhered to. Any unexpected performance degradation of the SCR and/or Oxidation catalyst system will result in a chemical analysis of the catalyst system to determine if these impurity tolerances were exceeded.

Impurity	Max. Concentration Limit
Alkaline Metals	5 mg/Nm^3 (wet)
Alkaline Earth Metals	1 mg/Nm^3 (wet)
Hydrochloric Acid; Chloride Compounds	100 mg/Nm^3 (wet)
Hydrofluoric Acid; Fluoride Compounds*	1 mg/Nm^3 (wet)
P_2O_5; Organic Phosphorous Compounds	0.05 mg/Nm^3 (wet)
Mercury & Zinc	0.1 mg/Nm^3 (wet)
Lead & Cadmium	0.1 mg/Nm^3 (wet)
Arsenic; Arsenic Compounds	0.005 mg/Nm^3 (wet)
Organic Silicon Compounds (e.g., Siloxanes); Silicon Halides	0.005 mg/Nm^3 (wet)

**Depending on exhaust gas composition and engine operating condition, a concentration of up to 20 mg/Nm3 may be acceptable. Please contact us for more information.*

ATTACHMENT 8

Blanco A Replacement Cost Scenarios

EPNG Blanco Compressor Station A Calculations (if use average test results from 2012-2023 and average operating hours from 2016-2021)

Unit No.	A-11	A-13	Notes
Total Capital Investment (TCI) ($)	$3,043,061	$3,043,061	$3,227/hp x 943 hp
Annualized Cost ($/yr)	$283,936	$283,936	8.53% interest rate over 30 years of useful life
Other Indirect Annaul Cost (OIAC) ($/yr)	$121,722	$121,722	EPA Cost Control Manual, OIAC = 0.04*TCI
Additional O&M Cost	$0	$0	Assume no incremental O&M Cost
Total Annualized Cost ($/yr)	$405,658	$405,658	
Baseline Actual NOx Emissions (tpy)	21.28	14.76	If use average test results (2012-2023) and average annual hours (2016-2021)
Estimated NOx Reduction (tpy)	18.23	12.28	Based on NM Ozone Rule NOx emission limit of 0.5 g/hp-hr and average annual hours (2016-2021)
2020$ Cost Effectiveness ($/ton)	$22,252	$33,034	
Cost Adjustment	1.34	1.34	Chemical Plant Cost Indexes (CY 2020 = 596.2, CY 2023 = 797.9)
2023$ Cost Effectiveness ($/ton)	$29,780	$44,210	

Chemical Plant Cost Indexes	
2019	607.5
2020	596.2
2021	708.8
2022	813.0
2023	797.9

EPNG Blanco Compressor Station A Replacement Cost Calculations (if use NMED's inflated baseline annual emissions)

Unit No.	A-11	A-13	Notes
Total Capital Investment (TCI) ($)	$3,043,061	$3,043,061	$3,227/hp x 943 hp
Annualized Cost ($/yr)	$283,936	$283,936	8.53% interest rate over 30 years of useful life
Other Indirect Annaul Cost (OIAC) ($/yr)	$121,722	$121,722	EPA Cost Control Manual, OIAC = 0.04*TCI
Additional O&M Cost	$0	$0	Assume no incremental O&M Cost
Total Annualized Cost ($/yr)	$405,658	$405,658	
Baseline Actual NOx Emissions (tpy)	54.8	44.6	If use NMED's inflated baseline annual emissions
Estimated NOx Reduction (tpy)	51.7	42.1	If use NMED's inflated NOx reduction % (94%)
2020$ Cost Effectiveness ($/ton)	$7,846	$9,636	
Cost Adjustment	1.34	1.34	Chemical Plant Cost Indexes (CY 2020 = 596.2, CY 2023 = 797.9)
2023$ Cost Effectiveness ($/ton)	$10,501	$12,895	

Chemical Plant Cost Indexes	
2019	607.5
2020	596.2
2021	708.8
2022	813.0
2023	797.9

Steven R. Torpey, PE
Sr Env Air Permitting Engineer

PROVIDING ENERGY. IMPROVING LIVES.

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E: Steve.Torpey@P66.com

September 20, 2024

Mr. Mark Jones
Air Quality Bureau
New Mexico Environment Department
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

Re: Regional Haze – Draft Plan and Rule 20.2.68 NMAC
DCP Operating Company, LP
Linam Ranch Gas Plant
Agency ID: 589

Dear Mr. Jones,

Phillips 66 Company (Phillips 66) is providing this comment on behalf of DCP Operating Company LP (DCP), as it is an indirect subsidiary.

The comment is specific to DRAFT rule 20.2.68.102.A. Table 1 NMAC. On Table 1, Linam Ranch Gas Plant RP Unit 32B is listed with an Emission Limitation of 25 ppmvd @ 15% O2 and a Compliance Deadline of 0 years.

On August 28, 2023, Phillips 66 submitted a letter to Michael Baca of New Mexico Environment Department (NMED) Air Quality Bureau (AQB) responding to outstanding questions for the Linam Ranch Gas Plant from a July 12, 2023 NMED meeting agenda. In the letter Phillips 66 committed that Turbine 32B would be upgraded to be compliant with 20.2.50 NMAC NOx emission limit of 50 ppmvd @ 15% O2. At the time of the August 28, 2023 letter, Turbine 32B did not have a schedule so was committed to be compliant with 20.2.50 NMAC, which would be by January 1, 2028.

On January 24, 2024, you emailed me asking for any updates regarding the schedule. I responded on February 5, 2024 that the bid was out and that there was an expectation, but not a guarantee, to be completed within the second group of the ozone precursor rule [20.2.50 NMAC]. The email indicated that this would have an expectation of the controls being updated by the end of 2025. I followed that up with an expression of regret that I did not have a more definitive schedule, but it was the best that I had at that time.

Based on these communications, Phillips 66 is taken aback by the proposed Emission Limitation and the Compliance Deadline. Since the proposed Emission Limitation for

Turbine 32B has been used in Regional Haze modeling and based on the performance tests of the other turbines at Linam Ranch Gas Plant Phillips 66 does not have a comment on the Emission Limitation, at this time. However, Phillips 66 proposes changing the Compliance Deadline from “0 years”.

When evaluating the Compliance Deadline of all the Units in DRAFT Table 1 of 20.2.68.102 NMAC, there is the following distribution:

- 3 years 80%
- 2 years 7%
- 1 years 0%
- 0 years 14%

While the “3 years” category is necessary for those units that need to start the engineering and purchasing process to meet the proposed Emission Limitation, the “0 years” would imply that the project is complete or at least very near complete. Phillips 66 asserts that while the project to upgrade Turbine 32B has been ongoing, the project does not meet the classification for “0 years”.

For these reasons, Phillips 66 proposes to move the Compliance Deadline for RP Unit 32B, at Linam Ranch Gas Plant, from “0 years” to “1 years”. This should not have an overall negative impact to the NMED Regional Haze State Implementation Plan (SIP).

If you have any questions regarding this notification, please feel free to contact me at the information above.

Sincerely,

Steven R. Torpey, PE (TX)
Sr. Env Air Permitting Engineer

From: Miller, Debra C
To: Jones, Mark, ENV
Cc: Peters, Melanie; Stacy, Andrea; Shepherd, Don; Salazer, Holly; Devore, Lisa M
Subject: [EXTERNAL] NM Regional Haze SIP Public Engagement Period
Date: Friday, September 20, 2024 10:08:09 AM

CAUTION: This email originated outside of our organization. Exercise caution prior to clicking on links or opening attachments.

Hi Mark

Thank you for notifying us that the draft of the New Mexico regional haze state implementation plan (SIP) was posted for informal public comment. We understand from your August 27, 2024, email that this is considered to be an opportunity for informal public engagement rather than a formal public comment period, and that a formal public comment period on the plan and new rule (20.2.68 NMAC – Regional Haze Requirements) will be forthcoming. With that in mind, we have reviewed the updated draft SIP and offer the following informal feedback.

Overall, the updated draft SIP will provide significant reductions in haze-causing emissions, particularly NOx. We appreciate the improvements that NMED has made to the draft SIP in response to comments we submitted during the FLM consultation period earlier this year. In particular, we commend NMED for reevaluating SCR as a control option for NOx at six facilities that were selected four-factor analysis. This identified opportunities to further reduce annual NOx emissions by 1,600 tons.

A few remaining questions and comments that were not addressed in the latest public draft SIP:

- Regarding NOx emission from the Artesia Gas Plant:
  - Were the individual reciprocating engine and boiler unit emissions below NMED's screening criteria for individual units (i.e., potential to emit less than 10 lb/hr or 5 tons/year)? Data from the 2017 National Emissions Inventory (NEI) suggests that several of Artesia's units did report annual emissions of greater than 5 tons.
  - Are the larger engines at the Artesia gas plant subject to NMED's Oil and Gas Sector – Ozone Precursor Pollutants Rule (NMAC 20.2.50.1)? If so, the NPS continues to recommend summarizing any anticipated NOx reductions from Artesia in the SIP.
- The draft FLM consultation SIP stated that application of dry-low NOx (DLN) technology would be required for Linam Ranch Gas Plant turbine 32b, but this is no longer listed as a required measure in the updated draft public SIP. Appendix D seems to suggest that DLN is already being added to turbine 32b for reasons not related to regional haze. Is this correct?
- For Blanco Compressor Station A, NPS continues to recommend that NMED consider engine replacement costs based on facility-wide utilization rates rather than a unit-specific basis.
- For the Cunningham Station Power Plant, the NPS continues to recommend the facility be required to install and operate SCR on units 1 and/or 2 no later than January 1, 2031, if either unit operates beyond the December 31, 2027 end of the second planning period.

Thank you for the opportunity to provide informal feedback on New Mexico's draft regional haze SIP during this informal public engagement period. The NPS finds that the NOx reduction measures identified in this updated regional haze SIP will provide necessary and significant contributions to reducing man-made visibility impairment in NPS-managed Class I areas, including Mesa Verde, Carlsbad Caverns, and Guadalupe Mountains National Parks. We commend NMED for its commitment to protecting these invaluable parks and for its careful consideration of the comments we provided during the FLM consultation period. We look forward to working with you as the plan is further developed. Please do not hesitate to contact us if you have any questions.

Debbie

Debbie Miller
Environmental Protection Specialist
NPS Air Resources Division
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WESTERN ENVIRONMENTAL LAW CENTER

September 20, 2024

Comments Submitted via email

New Mexico Environment Department
Air Quality Bureau
525 Camino de Los Marquez – Suite 1
Santa Fe, NM, 87505

Re: Comments on NMED's Draft Regional Haze SIP and Proposed Rule

Dear New Mexico Environment Department ("NMED"),

The Western Environmental Law Center ("WELC"), submits the following comments regarding the New Mexico Environment Department's Draft Regional Haze State Implementation Plan ("Draft SIP") and accompanying proposed rule, 20.2.68 NMAC – Regional Haze Requirements ("NM Haze Rule" or "Proposed Rule."). We appreciate the opportunity to provide feedback on the Draft SIP and Proposed Rule during this informal comment period—and appreciate that NMED is still considering prior comments and analyses submitted by stakeholders (including WELC) in revising the draft and developing a Final SIP.[1] We hope to see those considerations reflected in a Final SIP.

Broadly, we urge NMED to revise its SIP and use its ample authority under the Regional Haze Rule to embrace a more comprehensive approach to haze planning—an approach that improves visibility in Class I areas through more inclusive source identification and stronger emissions controls, *and* better fulfills NMED's environmental justice obligations, promotes public health, and advances statewide air and water quality, climate and just transition efforts.[2] We also offer some suggestions for how NMED can engage in a more robust public participation and consultation process moving forward—in accordance with NM Executive Order 2005-056 and its mandates to provide meaningful opportunities for involvement in decisions that may affect environmental quality and public health.[3]

[1] Prior comments submitted or signed by WELC and included in Appendix E to the SIP are incorporated by reference.
[2] For example, Executive Order 2019-003, "Executive Order on Addressing Climate Change and Energy Waste Prevention," (January 29, 2019), Available at https://www.governor.state.nm.us/wp-content/uploads/2019/01/EO_2019-003.pdf
[3] NM Exec Order No. 2005-056, "Environmental Justice Executive Order." https://www.env.nm.gov/wp-content/uploads/2022/06/EO_2005_056.pdf [Hereinafter NM EO 2005-056]

We also look forward to submitting more detailed, technical comments regarding source identification, four factor analyses, etc., during the formal Notice and Comment period later this year. In the present comments, we emphasize that this Regional Haze SIP, Proposed Rule, and accompanying public engagement processes present an opportunity for New Mexico to set a leading example for other states—not only with respect to air quality and visibility improvements in Class I Areas, but also with respect to climate, health, and environmental justice co-benefits statewide. This Haze SIP and Proposed Rule also represent an opportunity for NMED to enhance and reinforce its existing regulatory scheme, and to harmonize its regulations with those of other state agencies, particularly with respect to curtailing pollution from oil and gas sources. We hope NMED will revise its Draft SIP to seize these opportunities—and fully leverage the power of the Regional Haze Rule not only to protect New Mexico's treasured landscapes and unique ecosystems, but also to promote public health and advance environmental and climate justice for all who call New Mexico home, now and for future generations.

NMED Should Explore Opportunities for its Haze SIP to Strengthen and Reinforce Other State Air Quality and Environmental Regulations, and Vice Versa.

NMED states that the Regional Haze Rule requires consideration of "emissions reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment" in its long-term strategies.[4] These mandatory considerations of ongoing programs do not obviate the need for a strong Haze SIP that could further reduce emissions—instead, they underscore the importance of coordinated, rather than siloed, regulatory processes that strengthen and mutually reinforce one another to ensure the most comprehensive, enduring possible suite of air quality regulations. Coordinated regulatory efforts to address air pollution from oil and gas sources, in particular, should be integral to NMED's Haze SIP, given the WRAP data in the Draft SIP indicating that oil and gas point and non-point sources accounted for almost 80% of anthropogenic haze-causing (and health-harming) SO_2 emissions, almost 40% of anthropogenic NO_x emissions, and over 75% of anthropogenic Volatile Organic Compound (VOC) emissions in New Mexico from 2014-2018.[5]

Unfortunately, after a multi-year delay in issuing a draft SIP, NMED has missed some opportunities to coordinate its Haze SIP and Proposed Rule development directly with other relevant regulatory processes—for example, the state's "Ozone Precursor Rule," 20.2.50 NMAC, discussed in the Draft SIP—for which "pre-petition" outreach and an informal comment period began in 2020, with notice and hearing in 2021 and publication of the final rule in the NM register in July 2022. However, NMED can still identify opportunities for the Haze SIP to reinforce, enhance, and fill gaps in the rule's provisions for reducing or preventing emissions of ozone precursor pollutants such as NO_x and VOCs– pollutants that, as NMED notes, also contribute to visibility impairments in Class I areas[6]—and ensure that the Haze SIP does not *undermine* this and other relevant rules.

[4] NM Draft Haze SIP at 144-145; 40 CFR § 51.308(f)(2)(iv).
[5] *See* NM Draft Haze SIP at 83, Table 5-9. Draft SIP at 84, Table 5-11. Draft SIP at 86, Table 5-15.
[6] *Id.* at 145. The Draft SIP focuses primarily on NO_x and SO_2 emissions as the two largest anthropogenic contributors to visibility impairment. However, is it possible that the comparatively "minimal" contributions of other pollutants to the "Q" value in Q/d may reflect the enormity of NO_x and SO_2 emissions more than the "insignificance" of other emissions?

Moreover, it's not too late for NMED to coordinate its haze planning efforts with other ongoing and upcoming regulatory processes in the state—for example, proposed rules to address PFAS contamination from oil and gas sources, including possible groundwater contamination. As discussed in more detail below, one of the factors NMED must consider when setting reasonable progress goals for Class I areas and selecting reasonable progress measures for sources under the Regional Haze Rule includes "non-air quality environmental impacts." 40 C.F.R. § 51.308(d)(1)(i)(A). And within this broad category, one of the few examples of "non-air quality impacts" that EPA explicitly mentions in its 2019 Guidance is "generation of wastes for disposal and impacts on other environmental media, such as nearby water bodies."[7] Where these considerations in the Haze SIP might overlap with upcoming state rulemakings that seek to address similar impacts, this could present opportunities to harmonize New Mexico's air, land, and water protection rules so that they strengthen and reinforce one another.

NMED Should Analyze the Climate, Health and Environmental Justice Impacts of its Regional Haze SIP, and Incorporate These Considerations Into its Source Selection and Four-Factor Analyses.

The Regional Haze Rule requires states to consider four factors when setting reasonable progress goals for Class I areas, and when selecting reasonable progress measures for sources. These factors include the costs of compliance, the time necessary for compliance, *the energy and non-air quality environmental impacts of compliance*, and the remaining useful life of any potentially affected sources. 40 C.F.R. § 51.308(d)(1)(i)(A), (f)(2)(i) (emphasis added); Clean Air Act Section 169A(g)(1). The third factor directs states to consider the broader environmental implications of their regional haze plans, by requiring an analysis of the "non-air quality environmental impacts of compliance." See, e.g., *id.* § 51.308(d)(1)(i)(A). The Regional Haze Rule does not define "non-air quality and environmental impacts." However, as the U.S. Environmental Protection Agency ("EPA") has explained, the "Best Available Retrofit Technology" (BART) Guidelines—which include "energy and non-air quality environmental impacts of compliance" similar to the third reasonable progress factor—should inform a state's reasonable progress analysis in its haze SIP. 2 U.S.C. § 7491(g)(2); 40 C.F.R. § 51.308(e)(1)(ii)(A); 81 Fed. Reg. 66,332, 66,389 (Sept. 27, 2016). And under those guidelines, "non-air quality and environmental impacts" are to be interpreted broadly, and can be positive or negative. *Id*. EPA's own 2019 Regional Haze Guidance has also explained that "non-air quality environmental impacts" for reasonable progress measures encompass a broad scope of impacts, ranging from "generation of wastes for disposal and impacts on other environmental media, such as nearby water bodies," to "*any* beneficial non-air quality environmental impacts."[8] Moreover, in memoranda and in recent proposed approvals of other states' Haze SIPS, the EPA has stated that "energy and other non-air environmental factors" can include environmental justice and public health considerations.[9]

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[7] U.S. EPA (August 20, 2019) Guidance on Regional Haze State Implementation Plans for the Second Implementation Period [Hereinafter EPA 2019 Haze Guidance] at 33.
[8] *Id.* at 33, 42 (emphasis added).
[9] *See, e.g.,* Memo from Peter Tsirigotis to Regional Air Directors, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period, at 16 (July 8, 2021), available at https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf [Hereinafter EPA 2021 Haze Memo]

In short, climate, health, and environmental justice are squarely within the broad scope of the "non-air quality environmental impacts" reasonable progress factor, and NMED has ample authority and discretion to incorporate them into its Haze SIP. Yet the Draft SIP does not even mention climate or environmental justice, and mentions health only in distinguishing it from the visibility protection goals of the Regional Haze Rule and underlying Clean Air Act ("CAA") provisions. Draft SIP at 8, Section 1.3.1. It's true that the National Ambient Air Quality Standards are designed to address human health effects of criteria air pollutants, while the Regional Haze Rule and underlying CAA provisions are designed primarily to "protect visibility in Class I Areas by gradually reducing visibility-impairing anthropogenic air pollutants over time." *Id (citing* 42 U.S.C. §§ 7491 and 7492; 40 CFR §§ 51.300 to 51.309 (haze) and 42 U.S.C. §§ 7408 and 7409; 40 CFR §§ 50.1 to 50.19 (NAAQS). However, nothing in the Regional Haze Rule or the Clean Air Act *precludes* consideration of health impacts in a Haze SIP (or, as EPA has expressly noted, consideration of the environmental justice impacts inexorably linked to health).[10] Indeed according to EPA Region 6 staff, the Regional Haze Rule affords states "prodigious flexibility."[11] And after years of delay in issuing a Draft SIP, NMED's omission of health, environmental justice, or climate considerations— and indeed, the absence of any real discussion of non-air quality environmental impacts at all in the Draft SIP[12]—is particularly unfortunate. We hope NMED will incorporate these considerations into a revised Haze SIP, as discussed further below.

Environmental Justice and Health

The EPA defines environmental justice as "the fair treatment and meaningful involvement of all people, regardless of race, color, national origin, or income, in the development, implementation, and enforcement of environmental laws, regulations, and policies."[13] NMED echoes this definition, and goes on to explain the twin pillars of "fair treatment" and "meaningful involvement" as follows:

> Fair treatment means no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental and commercial operations or policies.
>
> Meaningful involvement means:
>
> – People have an opportunity to participate in decisions about activities that may affect their environment and/or health;
>
> – The public's contribution can influence the regulatory agency's decision;

[10] *Id.*
[11] NM Draft Haze SIP at 102 (stating that replacement and electrification requirements are well within the scope of the Regional Haze Rule and NMED's legal authority).
[12] For all sources subject to Four Factor Analyses in the Draft SIP, NMED indicates that there are no significant non-air quality environmental impacts, but does not discuss how it determined this.
[13] *See* U.S. Environmental Protection Agency, *Environmental Justice*, www.epa.gov/environmentaljustice.

– Community concerns will be considered in the decision-making process; and

– Decision makers will seek out and facilitate the involvement of those potentially affected.[14]

New Mexico's own Executive Order 2005-056 ("NM EO 2005-056") directs state agencies to provide opportunities for meaningful involvement, acknowledges the importance of cumulative impacts of exposure to multiple pollutant sources, and directs agencies to use available environmental and public health data —both to address these impacts, and "in determining siting, permitting, compliance, enforcement, and remediation of existing and proposed industrial and commercial facilities."[15]

The mandates of NM EO 2005-056 mirror federal requirements—requirements that EPA must ultimately meet in reviewing and acting on NMED's Haze SIP. Executive Order 12898 (EO 12898) requires each Federal agency to "make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations."[16] Even more recently, President Biden's January 27, 2021 "Executive Order on Tackling the Climate Crisis at Home and Abroad" (EO 14008) explicitly recognizes the inexorable links among climate, health, and environmental justice (which includes social and economic justice), and the corresponding need to address all of them in concert, with a whole-of-government approach.[17] NMED can facilitate EPA's compliance with Executive Order 12898 and Executive Order 14008 —and ensure its own compliance with NM EO 2005-056 — by including an environmental justice analysis in its Haze SIP.

NMED has ample discretion to include an environmental justice analysis—and analysis of associated health risks, impacts, and benefits— in its Haze SIP. EPA has expressly stated that "energy and other non-air environmental factors" for selecting reasonable progress measures can include environmental justice.[18] In a 2021 memorandum, the EPA encouraged states to consider equity and environmental justice impacts in the present haze SIP planning period, and noted that:

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[14] *See* https://www.env.nm.gov/general/environmental-justice-in-new-mexico/

[15] NM Exec Order No. 2005-056, "Environmental Justice Executive Order." https://www.env.nm.gov/wp-content/uploads/2022/06/EO_2005_056.pdf

[16] Exec. Order No. 12,898, 59 Fed. Reg. 32 (Feb. 11, 1994), available at: https://www.archives.gov/files/federal-register/executive-orders/pdf/12898.pdf.

[17] *See* Executive Order 14008, 86 Fed. Reg. 7619-7633, Tackling the climate crisis at home and abroad (January 27, 2021), *available at* https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/27/executive-order-on-tackling-the-climate-crisis-at-home-and-abroad/ Section 201 (Policy), for example, recognizes the threat to public health posed by the climate crisis and the need to "deliver environmental justice in communities all across America." Another part of the EO is expressly dedicated to "Securing Environmental Justice and Spurring Economic Opportunity," and Section 219 expands on the language of EO 12898, directing agencies to make environmental justice part of their mission, to expressly include climate, cumulative impacts, and "accompanying economic challenges." Section 221 creates the "White House Environmental Justice Advisory Council" (WHEJAC), which has since submitted draft recommendations to CEQ on an environmental justice screening tool and on updates to EO 12898.

[18] EPA 2021 Haze Memo, *supra* Note 9

> [T]his consideration could occur in different ways, including undertaking meaningful outreach to environmental justice communities; ensuring adequate opportunity for feedback on states' proposed strategies; and considering equity and environmental justice impacts as part of the technical analyses supporting the SIP, including source selection and four-factor analyses. For example, states could consider environmental justice when they consider the appropriate inclusivity of source selection and the suite of emissions control options that should be analyzed, and when they exercise their discretion in determining what is necessary to make reasonable progress towards the national visibility goal. In general, we encourage states to be aware of where sources of visibility impairing air pollutants are located and impacts they may have on environmental justice communities. *States have discretion to consider environmental justice in determining the measures that are necessary to make reasonable progress and formulating their long-term strategies*...[19] (Emphasis Added).

Oregon's Department of Environmental Quality ("DEQ") has exercised this discretion and incorporated a preliminary environmental justice analysis into its most recent haze SIP, as discussed further below. NMED should similarly exercise its ample authority and discretion to incorporate environmental justice analysis into its Haze SIP—and apply that analysis to its source selection, emissions control options, and reasonable progress determinations. Indeed, polluting facilities and activities, including major sources such as those identified in the Draft SIP, tend to be disproportionately sited in already-overburdened communities.[20] Yet NMED did not undertake any environmental justice analysis in the Draft SIP—or mention environmental justice in the Draft SIP at all. We urge NMED to correct this omission in a revised SIP—consistent with EPA's Guidance, NMED's stated commitments to environmental justice, and its mandates under New Mexico's own Executive Order 2005-056.[21]

In the Draft SIP, NMED *does* recognize its broad legal authority afforded by the Regional Haze Rule.[22]This same flexibility and breadth of legal authority affords NMED an opportunity to advance environmental justice through its Haze SIP. As an example of how NMED can begin to accomplish this, we offer a brief overview of the Oregon DEQ's preliminary environmental justice analysis in its most recent haze SIP. An environmental justice analysis in New Mexico may differ from the DEQ's in its precise parameters and methods, and should be crafted with the meaningful involvement of those who experience environmental justice impacts in the state firsthand. However, Oregon's efforts provide an example of a basic framework, and illustrate the overall feasibility of conducting such an analysis and incorporating it into a state's haze SIP.

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[19]Memo from Peter Tsirigotis to Regional Air Directors, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period, at 16 (July 8, 2021), https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf

[20] *See, e.g.,* Lejano et al., citing Carpenter, A., and Wagner, M. (2019). *Environmental justice in the oil refinery industry: a panel analysis across United States counties*. Ecol. Econ. 159, 101–109; *see also* Rachel Morello-Frosch et al., *Understanding the Cumulative Impacts of Inequalities in Environmental Health: Implications for Policy*, 30 HEALTH AFFAIRS 879 (May 2011).

[21] NM EO 2005-056

[22] NM Draft Haze SIP at 102.

Environmental Justice in Oregon's Regional Haze SIP

In its haze SIP for 2018-2028, Oregon's DEQ undertook an environmental justice analysis of "communities surrounding the facilities affected by [its] Regional Haze decisions." That analysis informed DEQ's "weight of evidence approach to qualitatively assess potential connections between a facility's emissions and visibility impairment in Class 1 areas, as well as co-benefits to surrounding communities (the non-air impacts [of the Four Factor Analysis]) potentially associated with facility controls."[23] This "weight of evidence" approach to evaluating potential controls succeeded DEQ's required four-factor analysis and helped verify that the agency included the appropriate sources in its reasonable progress determinations—it was *not* used to *eliminate* candidate sources from consideration.[24]

In developing its environmental justice analysis, the Oregon DEQ worked to create an "EJ Score" or "cumulative burden score" for people residing near each source.[25] DEQ first identified the demographic profiles of the communities immediately surrounding the facilities for which it was considering emissions controls. The agency then used data provided in the 2019 version of U.S. EPA's EJSCREEN to calculate the following measures, similar to an "EJ Index" in EJScreen, for each census block group in the state:

- Percent of population identifying as "minority"
- Percent of population living in households making less than 200% of the federal income poverty level
- Percent of the population over the age of 25 without a high school diploma
- Percent of the population self-identified as speaking English "less than well"
- Percent of population under 5
- Percent of population over 64[26]

For each facility, DEQ tallied a "1" for each indicator in the surrounding community (within 2.5 miles of the facility) with a value that exceeded the statewide average, or a "0" if the value was below the statewide average.[27] The analysis showed that most communities surrounding the affected Title V facilities were above the state average combined total score for these indicators.[28] If NMED were to undertake a similar analysis, it may want to consider using slightly different indicators, or another comparison point or threshold in addition to/instead of the statewide average, given the relatively high percentage of New Mexico's population overall that falls within each of the above indicator categories.[29]

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[23] Oregon Department of Environmental Quality ("DEQ"). Oregon Regional Haze State Implementation Plan 2018-2028. (August 27, 2021 public draft), at 37-38.*Available at* https://www.oregon.gov/deq/Regulations/rulemaking/RuleDocuments/RHSIP2021plan.pdf [Hereinafter Oregon Haze SIP)

[24] *Id.*

[25] *Id.* at 39 (*citing* Wu et al. 2020. Towards an assessment of cumulative environmental burden and disproportionate impact for Oregon communities. Poster presented virtually at American Geophysical Union Annual Meeting 2020).

[26] *Id.* at 39-40.

[27] *Id.*

[28] *Id.* at 40-41, Figure 3-3.

[29] See, e.g., https://www.epa.gov/sites/default/files/2016-08/documents/nepa_promising_practices_document_2016.pdf for other possible methods. While this EPA document

While NMED should tailor specific parameters to New Mexico, Oregon DEQ's efforts illustrate how the agency could begin to incorporate environmental justice into its determination of "the emissions reduction measures that are necessary to make reasonable progress." *See* 40 C.F.R. § 51.308(f)(2)(i). NMED should then assess how those measures will either reduce or exacerbate any environmental justice impacts on nearby communities. Incorporating environmental justice and related health impacts into its SIP in this way would help NMED assess the broader environmental implications of NMED's regional haze actions, fulfill its own environmental justice mandates, and maximize the benefits of the regional haze program. *See* 40 C.F.R. pt. 51, app. Y at § (IV)(D)(4)(i)(2). As the Oregon DEQ stated:

> "In considering an EJ score and vulnerable population rank, DEQ can identify locations where facility controls will have the co-benefit of not only improving visibility, but also reducing environmental burden on vulnerable communities. DEQ believes that emission reductions in Oregon should be targeted towards those communities that experience the greatest burden."[30]

Oregon's DEQ did not take the next step and assess specific, potential public health co-benefits of its haze SIP to the communities it identified in the preliminary environmental justice analysis, but did note that it was "confident that public health benefits will arise from PM and NO_x controls, in particular."[31] Indeed, an ever-growing body of peer-reviewed literature supports this assertion, finding tremendous health benefits associated with reduced emissions of PM, NO_x, SO_2, and other haze-causing air pollutants—particularly for those living in close proximity to the source.[32]

Suggestions for Providing Meaningful Opportunities for Involvement in Haze Planning

New Mexico's Executive Order 2005-056 on Environmental Justice emphasizes the importance of meaningful involvement in state agency decisions that may affect environmental quality and public health.[33] To facilitate meaningful involvement, EO 2005-056 directs agencies like NMED to ensure "that all publicly disseminated information, including websites, is available in Spanish and English, at a minimum, and in Tribal languages and dialects as appropriate for areas of the state where these languages are spoken." We urge NMED to develop more linguistically appropriate and accessible materials about its Haze SIP process, and offer some suggestions for removing barriers to meaningful involvement and meaningful Tribal consultation in subsequent meetings and comment processes, particularly for those in frontline communities. Barriers to meaningful involvement that NMED should keep in mind may include, but are not limited to, language barriers, lack of transportation, lack of reliable internet access, a prioritization of written comments over spoken word, lack of appropriate translation and interpretation, and lack of information publicized via linguistically and culturally relevant,

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focuses on environmental justice in the NEPA process, the guiding principles outlined on pp. 21-28 would likely prove helpful in an environmental justice analysis similar to that undertaken by the Oregon DEQ in its haze SIP.

[30] Oregon Haze SIP. at 38.

[31] *Id*. at 27

[32] See, e.g., Schraufnagel DE, Balmes JR, De Matteis S, Hoffman B, Kim WJ, Perez-Padilla R, Rice M, Sood A, Vanker A, Wuebbles DJ. Health Benefits of Air Pollution Reduction. Ann Am Thorac Soc. 2019 Dec;16(12):1478-1487. doi: 10.1513/AnnalsATS.201907-538CME. PMID: 31774324. (and references therein).

[33] NM Executive Order 2005-056, para. 1, 2.

widely-accessible channels. To address these barriers, NMED should, in public meetings and webinars, offer simultaneous interpretation and translation, and hold meetings in places that are accessible to members of frontline communities (this means accessible locations, and accessible facilities etc. for those individuals with disabilities, the elderly, those without access to transportation, and those with child care needs).

Climate Justice, Greenhouse Gas Emissions, and Climate Change

NMED should analyze how the reasonable progress goals and reasonable progress measures in its Haze SIP could affect greenhouse gas emissions, and in turn, climate change. Doing so would be consistent with the BART Guidelines and EPA's haze guidance and clarifying memorandum, all of which make clear that the "non-air quality environmental impacts" factor is intended to account for broader environmental impacts, such as those caused by climate change. These can include site-specific climate impacts to New Mexico's land, waters, ecosystems, and communities.

The IPCC's recent Sixth Assessment Report (AR6) also underscores the importance of climate *justice* and outlines its main components, stating:

> The term climate justice, while used in different ways in different contexts by different communities, generally includes three principles: distributive justice which refers to the allocation of burdens and benefits among individuals, nations and generations; procedural justice which refers to who decides and participates in decision-making; and recognition which entails basic respect and robust engagement with and fair consideration of diverse cultures and perspectives.[34]

Indeed, as with environmental justice impacts, climate change does not affect every community or region equally. Climate change impacts are often felt far beyond the source of emissions, and tend to fall most heavily on people and communities already overburdened by environmental, social, and structural inequities and harms.[35] Compared to impacts from more localized pollutant emissions, these climate impacts resulting from greenhouse gas emissions tend to be more difficult to trace directly to any one source. However, this does not mean that greenhouse gas emissions shouldn't be considered in Haze SIPs as a "non-air quality environmental impact"—instead, it underscores the cumulative significance of greenhouse gas emissions from every source —and the potential cumulative climate benefits of reducing those emissions from every source—no matter how "incremental" their contributions may seem individually.

When NMED determines "the emissions reduction measures that are necessary to make reasonable progress," it should assess how those measures will either reduce or exacerbate

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[34] *See* , IPCC AR6, Climate Change 2022: Impacts, Adaptation, and Vulnerability, Summary for Policymakers at 9, 13. *See especially* B.1.4. and B.1.7. *Available at* https://www.ipcc.ch/report/ar6/wg2/downloads/report/IPCC_AR6_WGII_SummaryForPolicymakers.pdf

[35] *See, e.g.,* EPA. 2021. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. U.S. Environmental Protection Agency, EPA 430-R-21-003. https://www.epa.gov/system/files/documents/2021-09/climate-vulnerability_september-2021_508.pdf

greenhouse gas emissions. *See* 40 C.F.R. § 51.308(f)(2)(i). For example, engine electrification or retirement of a coal-fired power plant would reduce or effectively eliminate greenhouse gas emissions from that source. If different reasonable progress measures being analyzed and considered for a source would result in different amounts of greenhouse emissions, NMED should use the Social Cost of Carbon/Social Cost of Greenhouse Gas Emissions to analyze and compare the climate impacts of each.[36] As with environmental justice, incorporating climate change into NMED's Haze SIP analysis can help maximize the "non-air quality" benefits of the Regional Haze Rule. *See* 40 C.F.R. pt. 51, app. Y at § (IV)(D)(4)(i)(2).

Conclusion

The Haze SIP presents an opportunity to strengthen and reinforce New Mexico's broader environmental regulatory scheme—and to promote public health and advance climate and environmental justice. However, the Draft SIP takes a more circumscribed approach to haze planning, despite NMED's acknowledgment that the Regional Haze Rule affords the agency "prodigious flexibility."[37] We hope NMED revises its SIP to embrace a more comprehensive and coordinated approach that not only fulfills all of its statutory and regulatory obligations, but also sets a nation-leading example of the powerful co-benefits of a strong haze SIP and accompanying rule. And we hope NMED finds these initial comments helpful in those endeavors.

Thank you for your consideration, and for the opportunity to comment on this Draft SIP. As NMED moves forward with its Haze SIP process, including formal notice and comment, we look forward to providing more detailed, technical comments and otherwise engaging further. Overall, we urge NMED to leverage the full power of the Regional Haze Rule to maximize air quality *and* "energy and non-air quality" benefits—including climate, health, and environmental justice benefits—to all New Mexicans, now and for future generations.

Sincerely,

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[36] *See, e.g.,* https://www.epa.gov/environmental-economics/scghg
[37] NM Draft Haze SIP at 102.

El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

No. EIB 24-49 (R)

Regional Haze State Implementation Plan Revision for the Second Planning Period and Proposed Companion Rule 20.2.68 NMAC – Regional Haze Requirements

Meeting | NMED and EPNG | October 22, 2024

Proposed Agenda

- Introductions
- An introduction to El Paso Natural Gas Company, L.L.C. (EPNG)
- EPNG's Goals
- Proposed Regional Haze SIP revisions applicable to EPNG
- Facility-Specific Discussions
  - Washington Ranch
  - Blanco A
  - Pecos River
- Summary of priority matters for resolution prior to hearing

Introduction: EPNG

- EPNG provides energy transportation services in a safe, efficient, and environmentally responsible manner for the benefit of people, communities, and businesses.
- It supplies natural gas to major utility providers, including Public Service Company of New Mexico, Southwestern Public Service, El Paso Electric, the New Mexico Gas Company, the Navajo Tribal Utility Authority, Zia Natural Gas, as well as the municipal utilities for the cities of Las Cruces, Socorro, Lordsburg and Deming.
- EPNG owns and operates a total of 2,781 miles of pipeline in 15 separate counties in New Mexico.
- In 2023, EPNG paid approximately $2.38 million in taxes to the State of New Mexico.
- In New Mexico alone, EPNG's parent company Kinder Morgan employs approximately 180 individuals, maintains a payroll of over $17 million, and pays approximately $6.8 million annually to local and state taxing bodies.

Introduction: EPNG

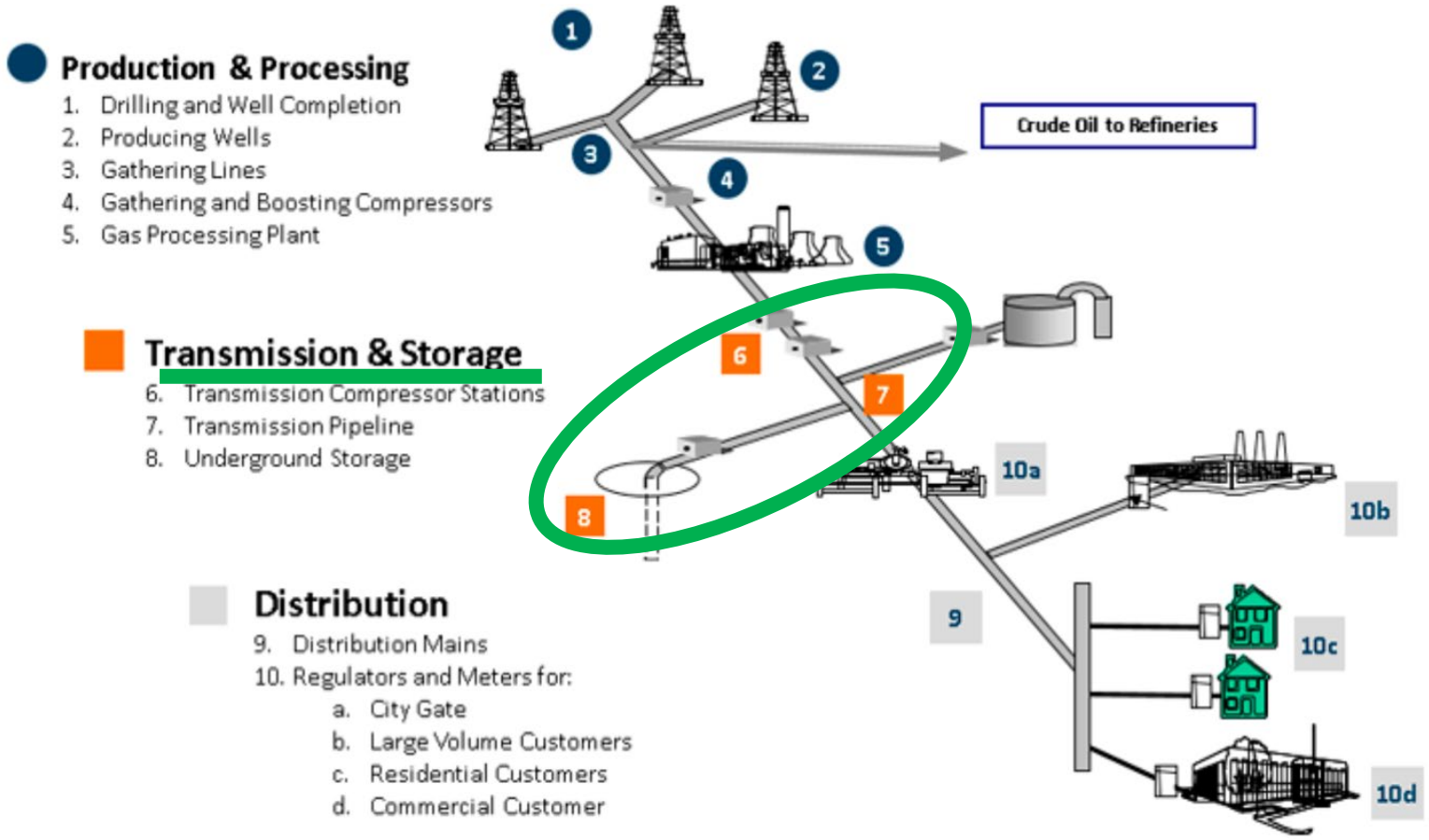


Figure 2. Schematic of the natural gas and petroleum system supply chain.

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

EPNG's Goals

- EPNG is committed to cost-effective and feasible emissions reduction projects as required by the Regional Haze program
- EPNG, and its affiliated entities, have actively participated in EIB rulemakings, collaborated with NMED, and proactively implemented emissions reduction strategies
  - Kinder Morgan, Inc. was a party to the Part 50, ozone precursor rulemaking, and worked closely with all stakeholders (including NMED) to assist in development of the engine and turbine emissions standards, the Alternative Compliance Plan (ACP) and Alternative Emissions Standards (AES) compliance options, as well as other important programs (i.e., LDAR)
  - Under the Part 50 ozone rule, Kinder Morgan's total NOx reduction under both the AES and ACP will be 1149.6 tons per year by 1/1/2027, and that does not even include reductions that have or will be achieved from implementation of the entirety of the Part 50 program
- Shared goal of resolution prior to rulemaking hearing before the EIB

Proposed Regional Haze SIP Revisions – EPNG

- Draft SIP Revision's Proposed Emissions-Rate Limits for EPNG Units

Facility	Unit	Proposed NOx Emissions-Rate Limit	NMED Basis for Limit	EPNG Position
Washington Ranch	1	3 g/hp-hr	Existing LEC	Does not oppose
Washington Ranch	2	3 g/hp-hr	Existing LEC	
Pecos River	A-02	3.64 g/hp-hr	SCR	Oppose based on cost (including past NMED finding), feasibility, and overall visibility impacts
Pecos River	A-03	4.05 g/hp-hr	SCR	
Blanco A	A11	0.5 g/hp-hr	Replacement	Oppose based on cost (including past NMED finding), feasibility, and overall visibility impacts
Blanco A	A13	0.5 g/hp-hr	Replacement	



Issues Applicable Across All EPNG Facilities

Use of *Actual Emissions* is Required

- EPA's 2019 Guidance directs NMED to use actual emissions when calculating cost-effectiveness of controls
  - The use of actuals is also consistent with the approach for BART
- NMED used a potential-to-emit (PTE) type approach for determining baseline emissions for Blanco A and Pecos River
  - This flawed assumption materially skewed results
- An example illustrates the point.
  - Consider engine *A* that runs only 10 hours a year and emits 1 ton of NOx during that operation and an otherwise identical engine, engine *B*, that runs 8760 hours while emitting 100 tons of NOx.
  - Using potential emissions would mean that engine *A* would be assessed to have emissions of 876 tons per year, and would therefore appear far more cost-effective than engine *B*.
  - In reality, however, engine *A* would actually be far more expensive to control based on its actual expected emissions. NMED's four factor analysis should avoid such perverse outcomes.

Use of *Actual Emissions* is Required (cont.)

- For Pecos River, NMED used representative operating hours (no objection), but adjusted turbines' tested NOx emission rates to 100% load assuming a linear relationship between NOx emission rate and percent load.
- For Blanco A, NMED relied on data from one emission test (in lb/hr) from the period of 2022-2023 for units A-2, A-3, A-4, A-9, A-11 AND A-13 and then extrapolated the one data point to 100% load to calculate the Baseline Actual Emissions ("BAE") rate (in lb/hr).
- **Inconsistencies with a proper BAE approach:**
  - All units operate at variable loads, and rarely at 100%.
  - For Blanco A, the look-back period was too short, with too small a data set. Non-representative results.
  - For Blanco A, NMED applied a linear function to engine load percent. This relationship is not linear.
  - For Pecos River, the NOx emission rate for turbines does not increase linearly with percent load; using this approach inflates emissions.

Use of *Actual* Emissions: RECOMMENDATION

- **Recommendation/request prior to rulemaking hearing:**
  - NMED should apply an appropriate measure of emissions baseline through the proper application of the Baseline Actual Emissions ("BAE") concept.
    - This is the approach directed by EPA in authoritative guidance applicable to the Regional Haze Rule: "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," dated August 20, 2019
    - This approach is consistent with Regional Haze BART analyses – a related and comparable analysis (i.e., statutes must be read together)
    - This is the approach applied in EPA's Prevention of Significant Deterioration ("PSD") program
    - This approach is practical: it is not potential emissions from a source that may affect visibility concerns, but actual emissions
    - This is the approach used in developing cost scenarios in the EIB Part 50 ozone rules rulemaking, and it has continued in implementation, through subsequent AES and ACP approvals. NMED approved an AES for Pecos River turbines that was based in part on a cost showing using actual emissions.

Visibility Impacts Should be Considered

- An overall evaluation of visibility impacts demonstrates NMED can make “reasonable progress” without requiring reductions from Blanco A or Pecos River.
  - Blanco A was selected based on proximity to Mesa Verde, but no reasoned explanation provided for a quantitative “may affect” determination
    - Reasoned explanation and quantification required by the statute, Regional Haze Rule, and EPA 2019 Guidance.
    - The Draft SIP (at 64) punts on this question, instead stating that “it is a challenging exercise to estimate with any degree of certainty what the quantitative impacts of individual point sources are at Class I Areas.”
  - Pecos River was subjected to four-factor analysis because of its proximity to Carlsbad Caverns.
- All Class I areas in New Mexico except Salt Creek Wilderness are projected to be below the glide path to natural visibility by 2028.

Visibility Impacts Should be Considered

- Blanco A and Pecos River emit virtually no SO2, the precursor for ammonium sulfate. Ammonium sulfate dominates visibility impairment on most impaired days at the relevant Class I areas.
  - Ammonium sulfate contributed 3.16 times more than ammonium nitrate to visibility impairment at Carlsbad Caverns on the most impaired days during 2018-2022.
    - Pecos River reported only 1.68 tons of SO2 in 2016 (even using NMED's assumption of emissions at permit limit in lb/hr), the inventory year for screening.
  - Ammonium sulfate contributed 2.75 times more than ammonium nitrate to visibility impairment at Mesa Verde on the most impaired days during 2018-2022.
    - Blanco A reported only 0.12 tons of SO2 in 2016 (again, using permit limit emissions rate), the inventory year for screening.

Visibility Impacts: RECOMMENDATION

- **Recommendation/request prior to rulemaking hearing:**
  - EPA's 2019 Regional Haze guidance provides (at 37) that states have "reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other [four] factors when determining whether a measure is necessary to make reasonable progress."
  - Similarly, EPA's 2021 Regional Haze guidance allows (at 13) states to "to choose to require controls at only a subset of those sources that constitute the vast majority of the visibility benefit."
  - Consistent with this guidance, EPNG requests that NMED propose in its technical testimony that no regulation of Pecos River and Blanco A is required on the basis that both facilities were screened in for Class I areas that have projected visibility below the natural visibility glide path and both facilities have *de minimis* levels of SO2 emissions.


Facility-Specific Discussions

Washington Ranch

Facility	Unit	Proposed NOx Emissions-Rate Limit	NMED Basis for Limit	EPNG Position
Washington Ranch	1	3 g/hp-hr	Existing LEC	Does not oppose
Washington Ranch	2	3 g/hp-hr	Existing LEC	Does not oppose

- EPNG does not agree with all the underlying analysis/methodologies applied (see slides relevant to Blanco A and Pecos River)
- However, EPNG agrees with the bottom-line conclusion that additional emission reduction opportunities exceed $10,000/ton reduced
- EPNG also does not oppose an emission rate limit of 3 g/hp-hr based on *existing* controls

Pecos River – Proposed Regional Haze SIP

Facility	Unit	Proposed NOx Emissions-Rate Limit	NMED Basis for Limit	EPNG Position
Pecos River	A-02	3.64 g/hp-hr	SCR	Oppose
Pecos River	A-03	4.05 g/hp-hr	SCR	Oppose

(Summary of basis for opposition on following slide)

Pecos River Must be Excluded

1. **Baseline Emissions Data:** Use of *actual* emissions, not a potential-to-emit (PTE) type approach, is required (discussed above)
2. **NMED Should Consider Projected Visibility Improvements:** An overall evaluation of visibility impacts demonstrates NMED can make "reasonable progress" without requiring reductions from Blanco A or Pecos River (discussed above)
3. **Consistency with Part 50 Ozone Rule:** The Air Quality Bureau recently approved an AES for Pecos River on the basis of cost-ineffectiveness
4. **The Four-Factor Analysis Requires Correction, Resulting in Revised Conclusions:** Corrected site-specific technical four-factor analyses demonstrate costs-per-ton exceed $10,000/ton for all units at each facility

Pecos River: The Broader Context

- **EIB Part 50 – Ozone Rule:**
  - Pecos River Units A-01, A-02, and A-03 are all part of an approved Alternative Emissions Standard (AES) under the New Mexico Ozone Precursor Rule, 20.2.50.113 NMAC, which was conditionally approved on June 26, 2023 by the New Mexico Air Quality Bureau (AQB)
  - These units qualified for an AES based on economic infeasibility because of their high cost-per-ton of emissions reductions, all of which exceeded $10,000/ton based on the assumptions EPNG recommends here
  - NMED's approval, through AQB, of the AES cost assessment just last year represents, per the Ozone Precursor Rule, a finding that "it is not . . . economically feasible for the individual engine or turbine to achieve the emissions standards"
  - NMED should not deviate from this finding now

Pecos River: Critiques of NMED Analysis

- **Capital costs for SCR are under-estimated:**
  - Reliance on SCR workbook (addressing *boilers*) is not applicable to the Pecos River *turbines*
  - The 2019 EPA Guidance directs use of accurate and specific data when available in place of generic information or estimates
  - In the recent Part 50 ozone rulemaking, NMED accepted EPNG-provided vendor quotes for SCR modifications at a similar facility
  - EPNG provided relevant specific cost data (and is working on an updated site-specific cost estimate); NMED has not used EPNG data to date

Pecos River: Critiques of NMED Analysis

- **Allowance for Funds Used During Construction (AFUDC):**
  - AFUDC is a generally accepted regulatory accounting method under which the cost of financing the capital construction projects incurred during the construction phase is added to the cost of the asset
  - AFUDC in construction projects follows the guidelines for accounting in FERC's Uniform System of Accounts, and these are FERC-regulated facilities
  - Importantly, NMED and KMI applied the AFUDC when developing cost-per-ton estimates for the EPNG (and other Kinder Morgan) units in the recent Part 50, Ozone Rulemaking
- **O&M Costs:** NMED relied on outdated default values, while EPNG relied on more accurate vendor quotes

Pecos River: Critiques of NMED Analysis

- **SCR efficiency of 90% is unachievable**
  - NMED cited an SCR efficiency rating of 90% its four-factor analysis calculations
  - This efficiency rating misunderstands EPA's Control Cost Manual, and NMED has presented no data to the contrary
  - The EPA Control Cost Manual is clear that SCR efficiency depends on type of catalyst and flue gas composition
    - As the exhaust temperature decreases below 700F, the reaction rate and resulting NOx removal efficiency begin to decrease
    - From the EPA Control Cost Manual, SCR efficiency in the temperature range for the Pecos River turbines is closer to between 63% and 73%
  - EPNG recommended a 70% reduction efficiency; NMED has not accepted to date

Pecos River: Corrected Four-Factor Analysis

- Correcting the flawed assumptions and data results in costs dramatically exceeding $10,000/ton.
  - A-02 would have costs of $26,790/ton.
  - A-03 would have costs of $28,369/ton.

- **Recommendation/request prior to rulemaking hearing:**
  - EPNG requests that NMED reflect these revised calculations in its submission of technical testimony, which would mean removing all Pecos River units from the proposed SIP for exceeding the cost threshold of $10,000/ton.

Blanco A – Proposed Regional Haze SIP

Facility	Unit	Proposed NOx Emissions-Rate Limit	NMED Basis for Limit	EPNG Position
Blanco A	A11	0.5 g/hp-hr	Replacement	Oppose
Blanco A	A13	0.5 g/hp-hr	Replacement	Oppose

(Summary of basis for opposition on following slide)

Blanco A Must be Excluded

1. **Baseline Emissions Data:** Use of *actual* emissions, not a potential-to-emit (PTE) type approach, is required (discussed above)
2. **NMED Should Consider Projected Visibility Improvements:** An overall evaluation of visibility impacts demonstrates NMED can make "reasonable progress" without requiring reductions from Blanco A or Pecos River (discussed above)
3. **Over-Inclusive Screening:** The established Q/d threshold is over-inclusive; Blanco A should not have been screened into the four-factor analysis
4. **The CAA Only Authorizes Control:** NMED does not have legal authority to require replacement (or electrification) of the Blanco A units. Additionally, replacement presents operational infeasibility issues for this site.
5. **The Four-Factor Analysis Requires Correction, Resulting in Revised Conclusions:** Corrected site-specific technical four-factor analyses demonstrate costs-per-ton exceed $10,000/ton for all units at each facility

Over-inclusive Screening : Q/d

- NMED adopted 5.6 Q/d as the cut-off "necessary to capture 80% of the total NOx and SO2 emissions from all New Mexico Title V facilities combined," citing to the Western Regional Air Partnership (WRAP) Protocol
- Concerns with NMED's approach:
  - WRAP suggest screening in at Q/d > 10, and only if **no sources are selected** does WRAP suggest stepping to a lower Q/d
    - Q/d of 10 captured 13 Title V sources responsible for 70% of the total NOx and SO2 from all Title V facilities in NM
  - WRAP and 2016 EPA Draft Guidance state that the 80% measurement is related to 80% of the visibility impacts, not total emissions (as applied by NMED)
  - Even if 80% was the right target, excluding Blanco A would have still captured sources that emit 79.98% of statewide NOx and SO2 emissions (see Table 6-2 of Draft SIP Revision (meaning, NMED only captures Blanco A by a rounding error)
  - In brief, NMED's screening approach was over-inclusive, not required, and is not technically defensible

Over-inclusive Screening: Q/d (cont.)

- Updated Site-specific information:
  - The Q/d analysis should be done using actual emissions. *See* EPA 2019 Guidance, at 17.
  - The Q/d approach NMED used also used 2016 emissions inventories.
  - These inventories are based on a PTE-like approach where the unit hours of operation were multiplied by the permit limit (in lb/hr) to calculate emissions.
  - Blanco A's units do not run at 100% load, and therefore NMED did not use actual emissions.
    - Whereas NMED's calculation concluded that Blanco A emitted approximately 356 tons of NOx + SO2, the **actual** emissions were approximately 51 tons.
    - Using 51 tons for the Q/d approach would yield a Q/d for Blanco A of 0.8, far below the threshold NMED used, and even farther below the threshold of 10 that WRAP suggests.

Over-inclusive Screening: RECOMMENDATION

- **Recommendation/Request Prior to Hearing**
  - NMED to more closely follow the WRAP Protocol it relies on and use a Q/d score of 10 as the threshold
  - Alternatively, use 7 as a threshold, as that appears to be a break point, after which the percentage of emissions pulled in drops off rapidly
    - As relevant to EPNG, this would eliminate Blanco A from further consideration
  - As another alternative, NMED can round 79.98% up to 80%, consistent with rounding conventions and determine that Blanco A's emissions are not required to hit an 80% threshold of Title V NOx SO2emissions that NMED identified
  - If NMED still applies the arbitrary 5.6 Q/d threshold, based on an accurate calculation of actual emissions, Blanco A's Q/d should be reflected as 0.8, which is well below the 5.6 threshold. At the least, Blanco A should be excluded on this basis.

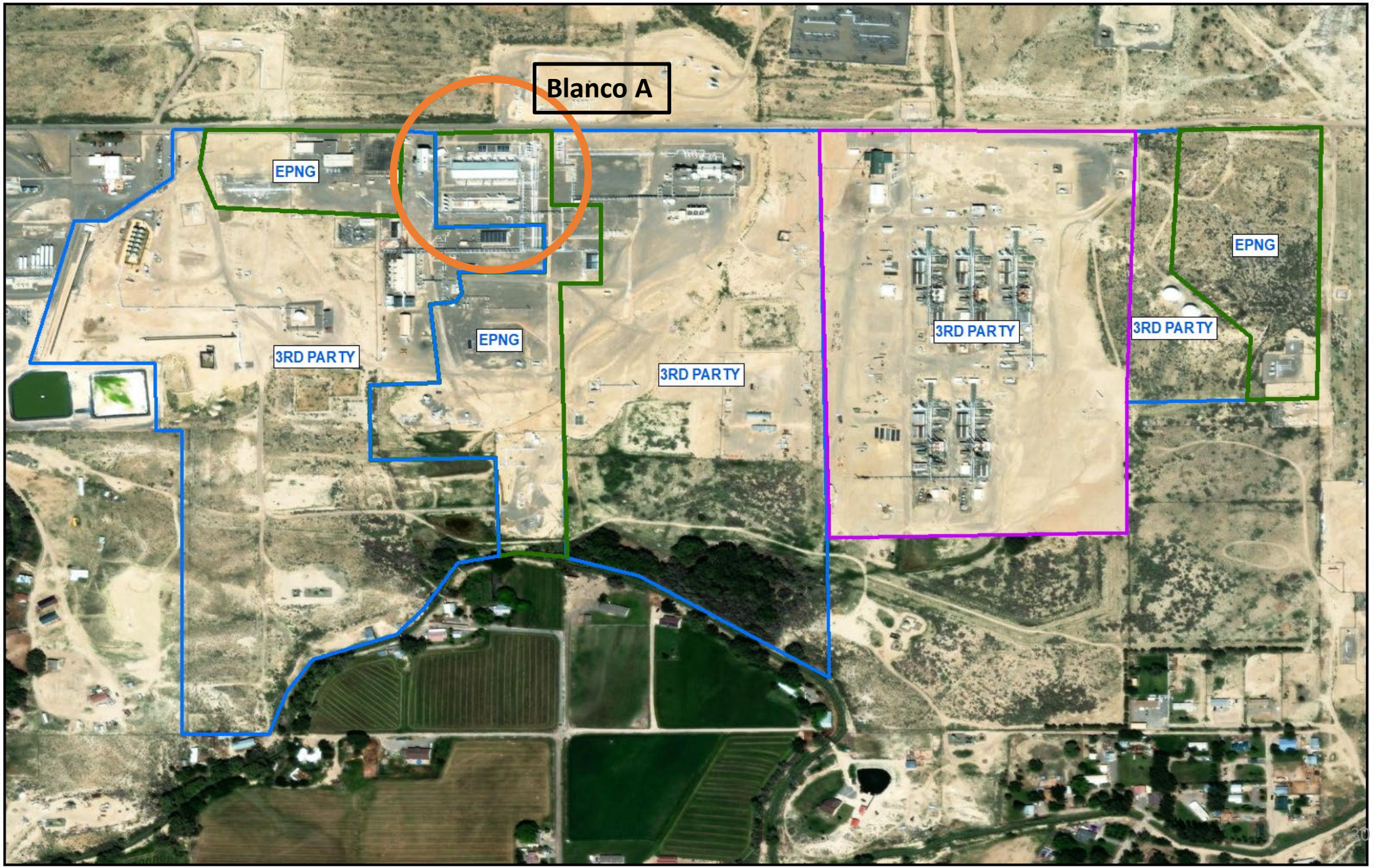
Replacement: CAA Only Authorizes Control

- NMED's four-factor analyses considered replacement and electrification
- Congress, EPA rules, and EPA Guidance clearly only authorize *control* of existing units.
  - The CAA Regional Haze program does not authorize EPA or any state-delegated agency to eliminate an emissions source (i.e., require replacement or electrification of a source).
- NMED only has flexibility *within* the authority delegated to it under the CAA Regional Haze program

Replacement: Technical Infeasibility Issues

- In addition to the lack of legal authority to require replacement, it is technically and economically infeasible to do so at Blanco A
- EPNG engineer: “This is the most complicated compressor station I’ve ever seen”
- EPNG does not own additional footprint at Blanco A to install replacement engines.
- Even if the existing engines were removed, there still would not be space and facility design is not suited for these types of engines.

[*See diagram on following page*]


Blanco A
EPNG
3RD PARTY
EPNG
3RD PARTY
3RD PARTY
3RD PARTY
EPNG

Replacement: RECOMMENDATION

- **Recommendation/Request Prior to Hearing**
  - Do not conduct four-factor analyses considering replacement of equipment
    - Replacement is not a control technique
    - Note: electrification was already eliminated from NMED's analysis due to feasibility and exorbitant costs, but should have been eliminated as an option entirely.
  - Regardless, replacement would be cost prohibitive (see next slides)
  - This would remove Blanco A from the four-factor analysis

Blanco A: Critiques of NMED Four-Factor Analysis

- **Allowance for Funds Used During Construction (AFUDC):**
  - Should be applied, as discussed above.

- **Replacement Cost Estimates:**
  - At Blanco A – replacement of the units themselves is over $7MM in present dollars, and based on actual vendor quotes (compared to NMED's estimate of $6MM per unit)
  - The prior cost data also do not consider facility-specific limitations and costs, which are now available
  - These costs are based on updated vendor quotes, whereas NMED's cost estimates are based on stale vendor quotes that do not appropriately reflect recent price increases.
  - The 2019 EPA Guidance directs use of specific quotes and data where available. *See id.* at 32 ("We recommend that *states exercise caution before accepting or rejecting controls based on generic cost estimates if adequately documented source-specific estimates are available or can be prepared*.")

Blanco A: Corrected Four-Factor Analysis

- Correcting for some data errors (i.e., inflated baseline emissions, assumed emissions reduction quantities, along with the capital costs shown above), the $/ton using the proper BAE amounts for A-11 and A-13 (of 21.28 tpy and 14.76 tpy, respectively) results in costs dramatically exceeding $10,000/ton.**
  - A-11 would cost > $29,780/ton.
  - A-13 would cost > $44,210/ton.
- **These costs *do not* consider site-specific considerations based on Blanco A's space limitations

- **Recommendation/request prior to rulemaking hearing:**
  - EPNG requests that NMED reflect these revised calculations in its submission of technical testimony, which would mean removing all Blanco A units from the proposed SIP for exceeding the cost threshold of $10,000/ton.

Summary of Recommendations/Requests

1. **Correct calculation methodologies as to Washington Ranch**
   a. Continue to conclude that additional emission reduction opportunities exceed $10,000/ton reduced based on updated calculations
   b. EPNG will not oppose an emission rate limit of 3.0 g/hp-hr based on *existing* controls
2. **Exclude Pecos River units from the proposed Regional Haze SIP on one or more of the following bases**
   a. NMED already found SCR at A-02 and A-03 is not economically feasible for Ozone AES
   b. Update cost-effectiveness calculation methodologies, concluding all control technologies for all Pecos River units exceed the $10,000/ton threshold
   c. SCR cannot feasibly hit 90% removal efficiency at Pecos River exhaust gas temperature
   d. Considering visibility conditions and de minimis SO2 emissions, no regulation required
3. **Exclude Blanco A units from the proposed Regional Haze SIP on one or more of the following bases**
   a. Corrected Q/d assessment would remove Blanco A from screening
   b. Exclude replacement as a consideration from the four-factor analysis
   c. Update cost-effectiveness calculation methodologies, concluding all control technologies for all Blanco A units exceed the $10,000/ton threshold
   d. Considering visibility conditions and de minimis SO2 emissions, no regulation required

Questions & Open Discussion

E.8 Hearing Phase Engagement

Additional comments were submitted to NMED as part of the engagement process after the petition, involving all parties that submitted entries of appearance in the hearing. Comments received during the Party review period from December 15, 2024 - January 7, 2025 are provided below. The following documents are included in this section (in reading order):

- El Paso Natural Gas Company Comments (1/7/2025)
- Enterprise Field Services Comments (1/7/2025)
- Western Environmental Law Center Comments (1/7/2025)

El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

Submitted Via Email

January 7, 2025

Air Quality Bureau
New Mexico Environment Department
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505
nm.regionalhaze@env.nm.gov

RE: No. EIB 24-49 (R)
El Paso Natural Gas Company, L.L.C.'s Response to the New Mexico Environment Department's December 13, 2024, Revisions to the Draft State of New Mexico Regional Haze State Implementation Plan Revision for the Second Planning Period (2019-2028)

To whom it may concern:

El Paso Natural Gas Company, L.L.C. ("EPNG") provides comment on the December 13, 2024 Revisions to the Draft Regional Haze State Implementation Plan ("SIP") Revision for the Second Planning Period (2019-2028) ("December Draft") prepared by the New Mexico Environment Department, Air Quality Bureau ("NMED"), in partnership with the City of Albuquerque Environmental Health Department ("EHD").[1] The December Draft makes modest changes to the earlier draft dated September 11, 2024 that was originally submitted to the New Mexico Environmental Improvement Board ("EIB") in the rulemaking proceeding EIB 24-49, *In the Matter of Regional Haze State Implementation Plan Revision for the Second Planning Period and Proposed Companion Rule 20.2.68 NMAC – Regional Haze Requirements*.

The December Draft addresses NMED's proposed approach and cost-effectiveness analyses undertaken for developing New Mexico's Regional Haze SIP Revisions for the second planning period. For EPNG in particular, the December Draft continues to include proposed emissions limits for three of EPNG's facilities: Blanco A Compressor Station ("Blanco A"), Pecos River Compressor Station ("Pecos River"), and Washington Ranch Storage facility ("Washington Ranch"), with only minor changes to calculation methodologies.

As discussed herein, NMED's analysis remains deficient and as a result, the EIB cannot require new emissions-rate limits on Blanco A and Pecos River. Given the relatively limited timeline for review, EPNG only provides brief responses on key issues within the December Draft. EPNG will provide a more fulsome response in its notice of intent to present technical testimony. EPNG also cites its September 20, 2024, letter ("September 2024 Letter") provided to NMED in response to

[1] EHD is responsible for CAA compliance within its jurisdiction in Albuquerque. For the sake of simplicity, this comment letter refers to NMED as the author of the Draft SIP Revision.

a public review draft of the September 11, 2024, draft SIP revision, and EPNG maintains the same positions set forth in that letter.

EPNG's responses to the December Draft are organized by facility, beginning with Pecos River, turning to Blanco A, and concluding with Washington Ranch.

I. Pecos River

A. Summary of Changes in the December Draft for Pecos River

It appears that NMED made three changes in the December Draft that are relevant to Pecos River.

1. NMED changed to the Chemical Engineering Plant Cost Index ("CEPCI") instead of the consumer price index ("CPI") to adjust for cost estimates that are denominated in dollars preceding 2023.
2. NMED used an estimate of 80% NOx removal efficiency for selective catalytic reduction ("SCR") rather than the original 90%,
3. NMED modestly increased the operations and maintenance ("O&M") costs for ammonia as a reagent and for catalyst replacement.[2]

As a result, the cost-per-ton of NOx reduction that NMED estimates for Pecos River Units A-02 and A-03 increased by approximately $2,000/ton ($6,000/ton to $8,000/ton for Unit A-02 and $7,000/ton to $9,000/ton for Unit A-03).[3]

B. EPNG's Response to the December Draft's Pecos River Analysis

All three changes in the December Draft for Pecos River were suggested in EPNG's September 2024 Letter. EPNG appreciates NMED's adoption of those important updates; however, NMED did not go far enough in correcting the base data and/or calculation methodologies for Pecos River (as described in detail in the September 2024 Letter). As a result, the cost-effectiveness analysis presented in the December Draft remains inaccurate, and insufficient to support new emissions limits for Pecos River. The September 2024 Letter noted use of the CPI was improper and that the CEPCI must be used, and the letter further urged that an appropriate SCR removal efficiency would be 70%, while also explaining that ammonia reagent costs were higher than NMED had used.[4]

[2] *Compare* December Draft Redline pdf page 807 (ammonia cost of $0.293/gallon and catalyst cost of $227/cubic foot), *with id.* at 808 ($0.529/gallon and $255/cubic foot).

[3] *See id.*, at pdf page 354.

[4] *See* September 2024 Letter, at 23 n.79 (noting that the CEPCI should be used for scaling up SCR costs for cost increases), at 27-28 (discussing range of SCR efficiency from 63% to 73% for the relevant Frame 3 turbine with a regenerator attached, causing the exhaust temperature to be between 500- and 580-degrees Fahrenheit, which is below the 80% NMED used), at 29 (ammonia cost is $1.80/gallon).

Again, EPNG appreciates the changes NMED made. However, EPNG briefly discusses the additional corrections that must be made to have a defensible Regional Haze cost-effectiveness analysis. These additional changes would result in excluding Pecos River from additional regulations under the proposed SIP.

- Pecos River Units A-01, A-02, and A-03 are all part of an approved Alternative Emissions Standard ("AES") under the New Mexico Ozone Precursor Rule, 20.2.50.113 NMAC, which was conditionally approved on June 26, 2023, by the AQB. As recently as 2023, NMED, through the Air Quality Bureau, approved these units for an AES based on **economic infeasibility** because of their high cost-per-ton of emissions reductions.[5] Costs have only increased since then. NMED has made no record showing of why it is appropriate to use different calculation methodologies to reach a different result.

- Even if an 80% removal efficiency is feasible at Units A-02 and A-03, the increased removal efficiency comes at a high capital cost and high operating cost because the SCR system would need to be built in an oversized fashion for additional NOx removal. Oversizing an SCR system in that fashion is expensive.

- Most importantly, the ***actual*** costs of adding a control technology should be used, consistent with the U.S. Environmental Protection Agency's ("EPA") own guidance, as discussed in the September 2024 Letter.[6] NMED has failed to use the ***actual*** cost data supplied by EPNG in its September 2024 Letter. Recognizing that NMED is now proposing an 80% removal efficiency in the December Draft, EPNG is still working with SCR vendors to determine the specific capital cost and feasibility of an SCR system that can achieve an 80% NOx removal efficiency. EPNG plans to include this information in its notice of intent to present direct technical testimony. However, initial estimates indicate that use of the ***actual*** cost data to achieve even the 80% removal efficiency will exceed the proposed $10,000/ton threshold, thereby excluding Pecos River from further regulation under the proposed SIP.

- As also noted in EPNG's September 2024 Letter, the SCR cost estimating tool that NMED used for estimating the costs of SCR installations is for larger ***boilers*** (25 MW, approximately 250 MMBtu/hr) rather than ***turbines***. As discussed in the September 2024 Letter, cost estimates for large boilers are unreliable for turbines, because they are an entirely different piece of equipment with different configurations and exhaust gas

[5] *See* NMED Letter Conditionally Approving AES (June 26, 2023). The approval was conditional "to the extent that, when any turbine is permanently replaced, the replacement turbine shall be considered 'new' pursuant to the rule." *Id.* at 1.

[6] *See id.* at 24 (noting that the EPA's 2019 EPA guidance for regional haze provides that states should use caution before accepting controls based on generic cost estimates if adequately documented source-specific estimates are available or can be prepared and that generic cost estimates are permissible when site-specific cost estimates are ***not*** available).

characteristics.[7] Further, the September 2024 Letter observed that "capital costs do not necessarily scale with unit size because of certain size-invariant capital costs,"[8] meaning capital costs for turbines that are only 56.45 MMBtu/hr (the size of the Pecos River turbines) would not scale down one-for-one. Thus, even the alleged "proxy" data that NMED used in place of the **actual** data is inaccurate and not defensible.

- In addition to capital costs, EPNG also emphasized that the aqueous ammonia needed to run an SCR system is also costly: approximately $1.80 per gallon based on an actual vendor quote.[9] The December Draft uses a value of $0.529 per gallon cost for ammonia, but the September 2024 Letter—**based on an actual vendor quote**—used $1.80 per gallon. In the December Draft, NMED claims to have "check[ed] with vendors for current prices" for these values,[10] but NMED has not provided copies of actual vendor quotes, in contrast with EPNG.[11] The record does not support NMED's position.

- NMED's December Draft also failed to correct its flawed methodology for assessing the baseline level of NOx emissions from Pecos River.[12] Whereas NMED's flawed method calculates baseline emissions of NOx as 116 tons per year ("tpy") and 112.2 tpy for A-02 and A-03, respectively, the actual representative baseline emissions value should be 81.7 tpy and 76.2 tpy, respectively.[13] Without any other changes in NMED's flawed assumptions, this change alone would cause the cost-per-ton of NOx reductions to be $11,386/ton and $12,564/ton, respectively, both of which are above the $10,000 threshold that NMED proposes.[14] NMED has presented no response to why the actual representative baseline emissions values of 81.7 tpy and 76.2 tpy, respectively, should not be used.

- Additionally, 2023 is not the appropriate year on which to base costs for a regulation that will be promulgated in 2025. For this reason, the CEPCI should be used to reflect inflation up to the most up-to-date CEPCI value at the time the December Draft is proposed on the rulemaking docket. This applies to Blanco A and Washington Ranch as well.

- Finally, NMED appears to have made no change in its analyses of SCR's visibility benefits to evaluate the impact of increased ammonia emissions resulting from ammonia slip,

[7] *Id.*

[8] *Id.*

[9] *Id.* at 29. *See also id.* at Attachment 3 (vendor quote).

[10] December Draft, at 760.

[11] *See* September 2024 Letter, Attachment 3 (vendor quote).

[12] *See id.* at 25-27 (noting flaws in NMED's method for evaluating the NOx emissions rate from Units A-02 and A-03).

[13] *Id.*

[14] Calculations scaling the cost-per-ton figures from the December Draft, at pdf page 754.

which has "the potential to impact visibility."[15] Potential impacts to visibility is the entire reason we are here. As EPNG already noted, "NMED has failed to consider an important aspect of the problem at this stage, which would result in arbitrary and capricious action if left uncorrected and if the final SIP revision requires SCR at Pecos River."[16] NMED must consider visibility impacts that would result from ammonia slip from SCR usage, and doing so through a photochemical model would be the most thorough method for assessing such impacts. For example, ammonia is itself a precursor of fine particulate matter because "it preferentially reacts with sulfuric acid (H_2SO_2) to form ammonium sulfate ($(NH_4)_2SO_2$). If more NH_3 is available, it then reacts with nitric acid (HNO_3) to form ammonium nitrate (NH_4NO_3)."[17] Notably, both ammonium sulfate and ammonium nitrate are the two most significant visibility-impacting substances that the proposed SIP targets.[18]

II. Blanco A

A. Summary of Changes in the December Draft for Blanco A

It appears that NMED made one change in the December Draft that is relevant to Blanco A: NMED uses the CEPCI to adjust for cost estimates that are denominated in dollars preceding 2023. This increased the cost of replacement for Units A11 and A13 to go from approximately $6,000 and $8,000, respectively, to $7,000/ton and $9,000/ton, respectively.[19] Additionally, the change in assumption drove up the cost of two low-emissions combustion projects above the proposed threshold of $10,000/ton for Unit A11.[20]

B. EPNG's Response to the December Draft's Blanco A Analysis

As noted above, EPNG appreciates the change from using the consumer price index to the CEPCI. However, the September 2024 Letter included a variety of other important recommendations that NMED failed to heed. For the reasons discussed below and in the September 2024 Letter, replacement is inappropriate and unsupported for Blanco A Units A11 and A13.

- NMED does not have authority under the Clean Air Act's regional haze provision to require

[15] *See* September 2024 Letter, at 31; *see also id.* at 30-32 (discussing other drawbacks of ammonia, including required safe handling).

[16] *Id.* at 31.

[17] *See* U.S. Dep't of Agriculture Air Quality Task Force, *Ammonia Emissions: What to Know Before you Regulate* at 4 (Oct. 1, 2014) https://www.nrcs.usda.gov/sites/default/files/2022-10/AAQTF-Accomplishments-Ammonia-White-Paper.pdf.

[18] *See, e.g.*, December Draft at xi-xii ("NMED's analysis of monitoring trends shows that ammonium nitrate (NH_4NO_3) and ammonium sulfate ($(NH_4)_2SO_4$) are important contributors to visibility impairment at all Class I Areas on both the most impaired days and clearest days.").

[19] *See* December Draft Redline, at pdf page 355. *See also id.* at pdf page 720 ($7,365/ton and $9,045).

[20] *See id.* at pdf page 365.

replacement. This is explained in more detail in the September 2024 Letter.[21] And to the extent that NMED attempts to rely on the State of New Mexico's authority to require replacement, doing so would run afoul of the federal preemption of interstate natural gas pipelines under the federal Natural Gas Act and regulation subject to the Federal Energy Commission's jurisdiction.[22] Please refer to EPNG's September 2024 Letter for a detailed legal analysis. A failure to regard this threshold issue creates significant legal exposure for the proposed SIP.

- Blanco A should never have been screened in for further evaluation of emissions reductions in the first place. In addition to using a flawed screening methodology that calls into question the reasonableness of the entire proposed SIP,[23] the screening was especially problematic for facilities with low SO_2 emissions, including Blanco A and Pecos River. Blanco A is an especially strong example of the point, and the additional data provided in the December Draft underscores that. The December Draft shows the emissions profiles of facilities that were ***not*** selected for further analysis. Notably, the two facilities immediately following Blanco A on the list of facilities ranked by combined NOx and SO_2 emissions had far higher SO_2 emissions than Blanco A.[24] As noted in the September 2024 Letter, SO_2 has a larger impact on visibility impairment than does NOx.[25] It is therefore especially arbitrary to subject Blanco A to emissions controls when other facilities that very likely have greater visibility impacts were not evaluated for emissions reductions. Finally, and as noted in the September 2024 Letter, even if NMED were to follow its (flawed) approach of using the aggregate 80% combined emissions of NOx and SO_2, NMED should have at the very least rounded 79.98% up by 0.02% to 80.0%, which would have eliminated Blanco A from further consideration.[26] Indeed, within the December Draft, NMED rounded ***down*** $10,138/ton to $10,000/ton to determine that SCR should be required for another operator's unit.[27]

- Proposing to require replacement of units is unlawful, as noted above. Even if it were lawful, replacement at Blanco A is also infeasible. Given the short turn-around time for EPNG to prepare its September 2024 Letter (18 business days), EPNG did not have an opportunity to fully complete an engineering and design evaluation considering

[21] September 2024 Letter, at 6-9.

[22] *See id.* at 10-11.

[23] *See id.* at 11-14. As explained in the September 2024 Letter, the Western Regional Air Partnership ("WRAP") only calls for going below a Q/d of 10 as a screening threshold if no sources are selected or identified at that level, which is clearly not the case. *Id.* at 13.

[24] *See* December Draft, at 94-95 (emissions of 271 and 108 tons of SO_2, for Empire Abo Gas Plant and San Juan River Gas Plant, respectively, compared with 0.12 tons of SO_2 for Blanco A).

[25] September 2024 Letter, at 14 n.59.

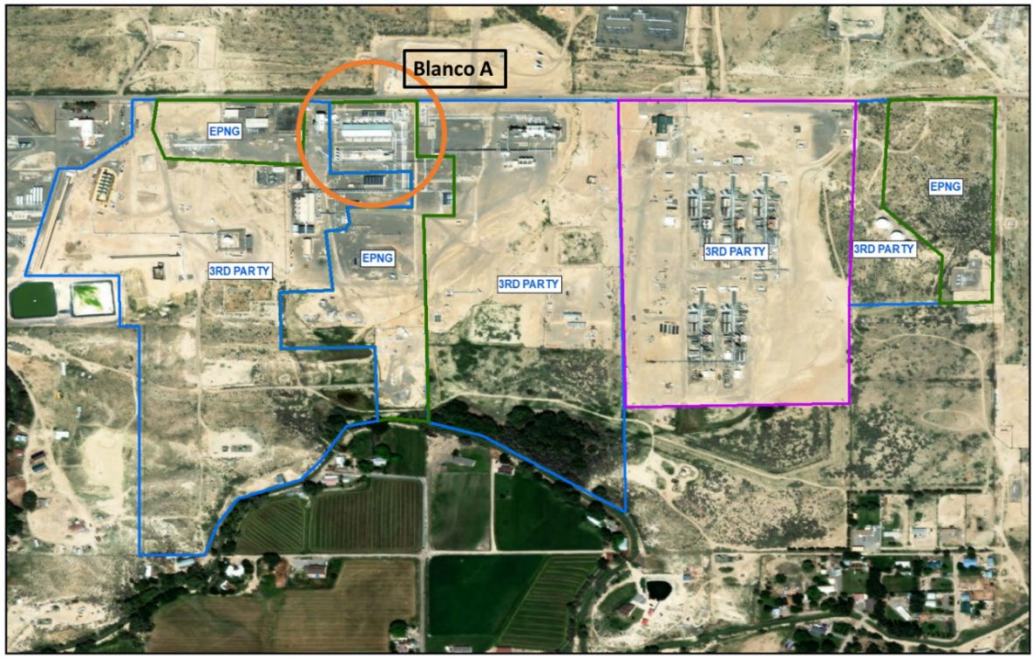
[26] *See id.* at 14 (identifying other instances where NMED would round up).

[27] *See* December Draft, at 125-26 (proposing regulation of unit 2), pdf page 1518 (showing cost of $10,138/ton for unit 2).

replacement of engines at Blanco A. However, following submittal of the September 2024 Letter, EPNG continued evaluating the engineering requirements for replacement and identified dramatic feasibility and cost concerns in so doing. Some of this specific data is new to NMED, so we respectfully request NMED carefully review and consider the same. EPNG will be filing additional detailed information regarding infeasibility in its notice of intent to present technical testimony, and EPNG would welcome a discussion with NMED on this particular topic in advance of that submission timeline.

- The existing compressor building (circled in **Figure 1**, below) cannot accommodate replacement engines because it is already filled by 14 existing engines. Additionally, the existing engines are lower speed engines while the new engines would operate at higher speeds, which is an unavoidable feature of modern engine design. These higher-speed engines are incompatible with lower-speed engines due to differing vibration characteristics, which could lead to operational disruptions and costly repairs if they were operated within the same building. In short, this presents a significant safety issue.[28] Moreover, the current emergency shutdown system at the site, which integrates third-party lines due to the site's historical configuration, is illustrated in **Figure 1**. Installing a new engine would render the existing emergency shutdown system inadequate, necessitating the development and implementation of an entirely new system. This would dramatically increase both costs and complexity of the project and require close coordination with other operators, necessarily delaying implementation.

Figure 1 – Blanco A and Surrounding Facilities



[28] *See* **Attachment 1**, at 74-75, 80-82 (discussing vibration issues).

- **Second**, replacement horsepower cannot be installed elsewhere at the Blanco A site. Because there is no existing space in the compressor building where engines are currently housed at Blanco A, EPNG also investigated whether it would be possible to add replacement compression horsepower elsewhere at the Blanco A site. However, **Figure 1** demonstrates that there is no space left at the site that EPNG owns that is directly adjacent to the compressor building at Blanco A. As shown in that figure, the area of the overall parcel where Blanco A is located is fully occupied by the compressor building, piping, and other facilities. That means the only area within the contiguous EPNG-owned site where there could be sufficient space lies to the south. But this would not work either because compressor stations must have an emergency shutdown system that can blowdown piping at a location where the gas will not create a hazard.[29] Further, the emergency system must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building. Building compressor station facility components near another entity's equipment would therefore require all third parties to operate under the same emergency shutdown system, which is not feasible, practical, or safe. And even setting these safety concerns aside, running piping to the southern part of the existing parcel would be highly complex and increase costs well beyond the proposed $10,000/ton reduced threshold.[30]

- Finally, as with NMED's estimated baseline emissions for Pecos River, NMED must also correct its assessment of baseline emissions for Units A11 and A13 at Blanco A. NMED assessed baseline emissions of 54.8 tpy and 44.6 tpy for Units A11 and A13, respectively. But this method relied on improperly scaling the engine load up to 100% and using too short of a look-back period that does not capture the full business cycle.[31] NMED should have instead used 21.28 tpy and 14.76 tpy, respectively, as the baseline actual emissions for Units A11 and A13. Even if NMED changed no other additional parameters—and that alone would be an indefensible position given the technical and cost feasibility issues at this facility—using the correct emissions volume in the cost-effectiveness evaluation would make replacement for both units exceed the proposed $10,000/ton threshold, with costs of $18,966/ton and $27,331, respectively.

[29] *See* 49 C.F.R. § 192.167.

[30] Additionally, if NMED considers justifying replacement based on EPNG obtaining rights to *additional* land to get around the infeasibility of on-site replacement, then NMED would also need to show such an approach is even within the EIB's authority and is feasible. And even if NMED (wrongly) concludes that it is legal and feasible to require EPNG to obtain access to lands not owned or leased by EPNG, NMED would still need to show that acquiring rights to another parcel would be cost-effective. It would ***not*** be. The cost of obtaining new land, clearing that land for construction, constructing a new building housing additional compression horsepower, and obtaining all associated permits would add onto the already high capital costs of purchasing a new engine of approximately 2,000 horsepower that EPNG would use to replace the two engines.

[31] September 2024 Letter, at 16-18.

III. Washington Ranch

A. Summary of Changes in the December Draft for Washington Ranch

It appears that NMED made one change in the December Draft that is relevant to Blanco A: NMED uses the CEPCI to adjust cost estimates that are denominated in dollars preceding 2023. This caused the cost estimates for the two units at Washington Ranch to increase from $277,880/ton and $1,000,013/ton to $315,558 and $1,135,609/ton, respectively.[32] None of those costs are at or below the proposed $10,000/ton cost-effectiveness cut-off.

B. EPNG's Response to the December Draft's Washington Ranch Analysis

As discussed in the September 2024 Letter, EPNG does not agree with NMED's Washington Ranch cost-effectiveness calculation methodology, including the overestimation of baseline actual emissions. This methodology flaw should be corrected. However, because NMED does not propose any additional controls be added to Washington Ranch, EPNG does not oppose the ultimate recommendation in the December Draft that Washington Ranch would not be required to undertake any projects and would instead be required to maintain the NOx emissions rate achieved with existing control measures.

IV. Conclusion

NMED must incorporate the recommendations provided in this letter in any updated proposal in the rulemaking matter EIB 24-49.

If you have any questions about our response, please contact Weiwen Daly by email at Weiwen_Daly@kindermorgan.com or by phone at 303-914-7616 or me by email at Tom_Mitchell@kindermorgan or by phone at 713-420-3463.

Sincerely,

/s/ R. Thomas Mitchell

R. Thomas Mitchell
Manager, EHS

Attachment:

- Attachment 1: White *et al.*, Advanced Topics in Pulsation and Vibration Control (2020).

[32] *Compare* December Draft Redline at pdf page 902, *with id.* at 903.

El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

Attachment 1
to EPNG Comment Letter on December Draft

White *et al.*, Advanced Topics in Pulsation and Vibration Control (2020)



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Advanced Topics in Pulsation and Vibration Control

GMC 2020

Southwest Research Institute
Benjamin A. White, P.E.
Eugene "Buddy" L. Broerman
Sarah B. Simons

Overview

- **Pulsations / Acoustics Basics**
  - Theory and Equation of State Topics
- **Pulsation Mitigation for Positive Displacement Machinery**
  - Low/Medium/High Pressure Machines
  - Advanced Pulsation Attenuation Devices
    - Commercially Available, In Development, New Research
  - Effect of Changing Operating Conditions/Reverse Flow
  - Pump Pulsation Mitigation
- **Other Advanced Pulsation Topics**
  - Wet Gas Considerations
  - Mixed Compression
  - High Frequency Pulsations—Centrifugal Compressor and Valves
- **Mechanical Design**
  - General Design Guidelines
  - Advanced Topics: Skid and Foundation Analysis, Screw Piles, AIV

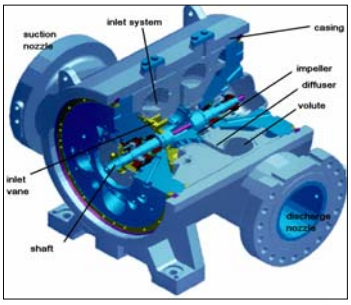
Poll #1 - What is your company role?

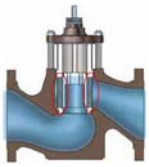
Acoustics / Pulsation Basics

Sources of Pulsations...


Reciprocating Compressors –most common


Piping Dead Leg Stubs




Control elements (e.g., valves & regulators)

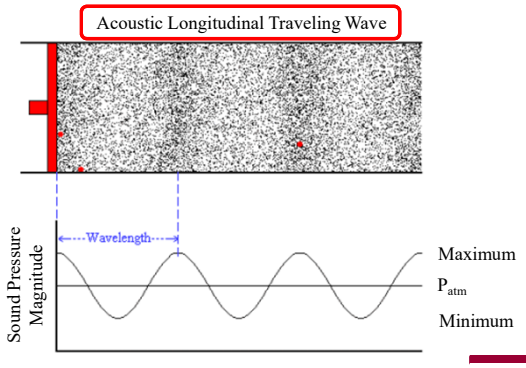

Protrusions into the pipe

Pulsation: What is it?

(Image courtesy of the Institute of Sound and Vibration Research)

- Pulsation is a periodic fluctuation in both local pressure and velocity at each point along a pipe (Bernoulli's equation).
- Pulsations (a.k.a., acoustic waves) can travel both upstream and downstream from the source - at the speed of sound of the flowing fluid.

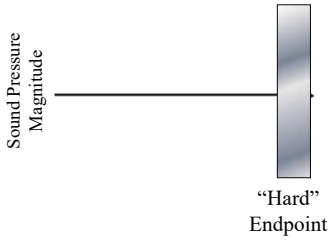
Example of a Positive Pressure Wave originating in cylinder and moves through the piping at the Speed of Sound



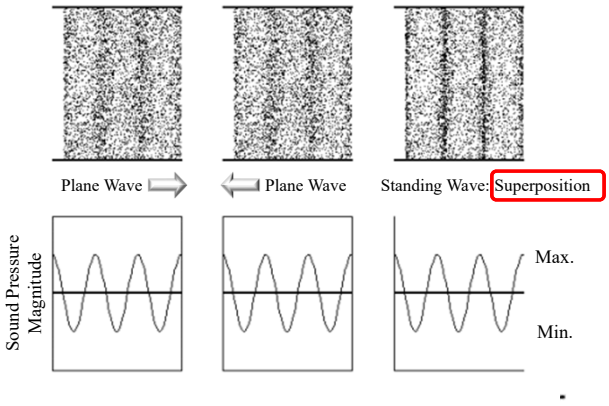
Creating Standing Waves from Traveling Waves

(Images courtesy of the Institute of Sound and Vibration Research)

Reflection of a pulsation (pressure) wave off a hard end, such as a blind flange or valve...

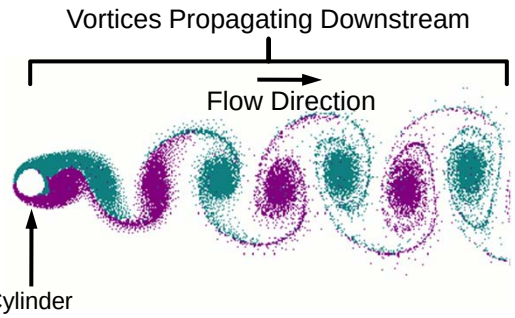


Creating standing waves from traveling waves...



Vortex-Shedding as a Pulsation Source

- Interaction of an otherwise steady flow stream with piping features can give rise to substantial unsteady fluctuations.
- Culprits can include:
  - Tees, bends, reducers
  - Flow Restrictions: Valves and orifice plates
  - Obstructions: Struts, instrumentation locations (thermowells), tubes
- Most common source of low frequency pulsations in high flow piping systems is excitation of dead legs or stubs.
- Higher frequency pulsations are associated with thermowells/instrumentation, valves and orifices.

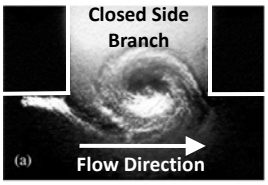




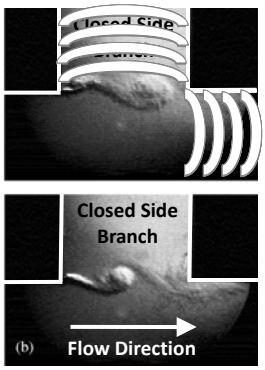
Vortex Shedding: Closed Side Branches or Valve Cavities

(Images courtesy of S. Dequand, et al.)

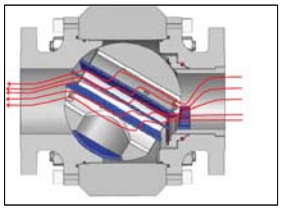
- The shear layer of the flow will separate at changes in piping geometry and can shed vortices at periodic intervals, creating areas of high and low velocity (and pressure)
- Closed side branches and valves generate vortices at the fundamental or higher-order modes.
- Excites acoustic natural frequency of cavity
- These can cause excessive pressure drop, audible discrete noise, high amplitude pulsations and vibrations, and distorted pressure signals.



Fundamental mode



Second-order mode



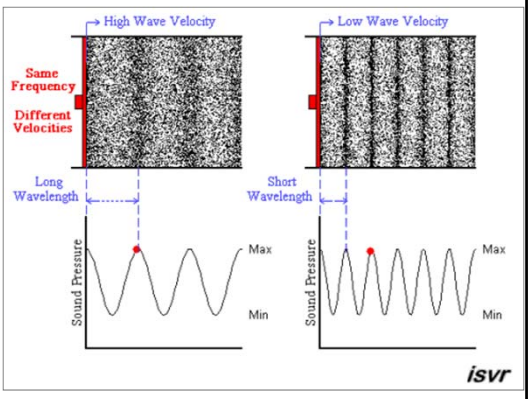
Sound Speed
How Fast Is It Traveling?

- Sound speed: How fast the wave can travel through the medium=elasticity/density
- Sound speed is temperature dependent
  - For an ideal gas, the speed of sound is proportional to $\sqrt{T}$

$$c = \sqrt{\frac{\gamma RT}{M}}$$

c = speed of sound
γ = ratio of specific heats, C_p/C_v
R = ideal gas constant
M = molecular weight

- Sound speed is generally higher for liquids than gasses
  - Depends upon stiffness or compressibility of material
  - Exceptions: Hydrogen, other low density gases



Same forcing frequency, different speed of sound

Image courtesy of the Institute of Sound and Vibration Research

Equation Of State (EOS)

- Various EOS exist to calculate thermo properties in mixtures each using different mixing rules. The implementation of mixing parameters and rules may vary based on the implementation in a particular software.
  - Common EOS: BWR, SRK, Gerg 2008, AGA8, NIST—last three are industry standards
- For gases with significant amounts of unusual components such as CO_2, SO_2, water, heavier hydrocarbons, operating points near critical points or phase changes, and for many refinery mixtures (liquids and gases), equations of state can have significant amounts of error.

If a higher degree of accuracy is needed for measurement or performance it is recommended to:

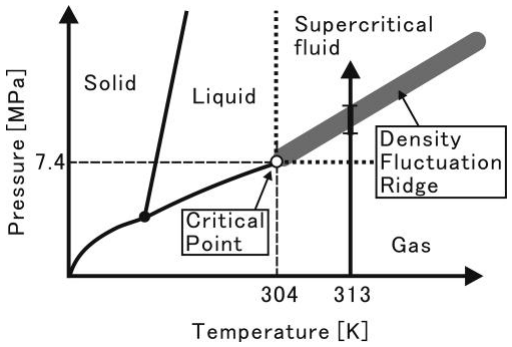
a. Have the mixture evaluated to determine the best EOS for that application and the associated deviations

b. Test the physical properties of that mixture at the planned operating points

Equation Of State (EOS)

- Operating in the supercritical regime
  - Density of a liquid, but SOS or "compressibility" of a gas.
  - Density ridge exists creating widely fluctuating pulsation amplitudes

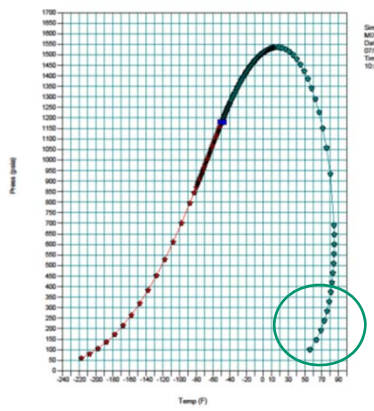
	Temperature (°C)	Pressure (bar)	Density (kg/m³)	Cp/Cv	Sound Speed (m/s)
1	168.00	42.260	140.34	2.2120	144.13
2	169.00	41.260	127.69	1.9295	150.31
3	169.00	43.260	147.39	2.3242	142.79



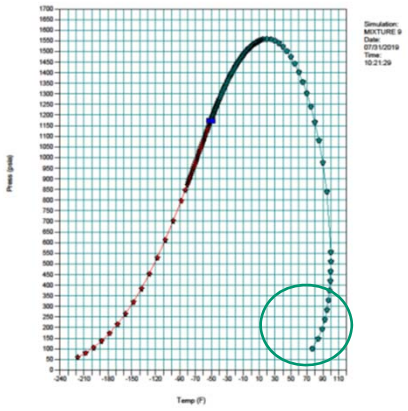
- Gas Composition Analysis
  - Must be performed up to C14
  - Small variations in heavier hydrocarbons can shift dewpoint (wet gas) and other thermophysical properties

Dewpoint Calculations
Small Increases in C10+ Components

Mixture 7: 15 ppm C10,C12



Mixture 9: 60 ppm C10, C12



Dewpoint Shifted by 20 deg F

Pulsation Excitation Frequencies

Compressor Excitation Frequency

$$f = n\frac{rpm}{60} \qquad where\ n = 1,2,3,...$$

A 300 rpm unit generates pulsation at 5, 10, 15, 20, ….Hz

A 900 rpm unit generates pulsation at 15, 30, 45, 60, ….Hz

Vortex-Shedding Excitation Frequency

$$S_t = f_s d/U$$

f_s is the shedding frequency or frequency, d is characteristic dimension of object generating disturbance (such as diameter) and U is flow speed (velocity)

The Strouhal number or range of numbers is determined experimentally generally in the range of 0.10-0.55

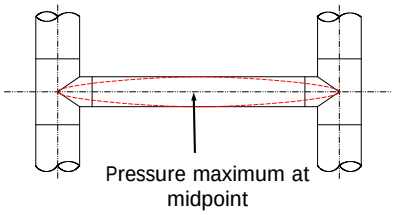
Acoustic Natural Frequencies: Longitudinal Modes

Half-Wave Response

$$f = n\frac{c}{2L}$$

f = Response frequency (Hz)
c = Velocity of sound (ft/sec)
L = Acoustic length of pipe span (ft)
n = 1,2,3,…

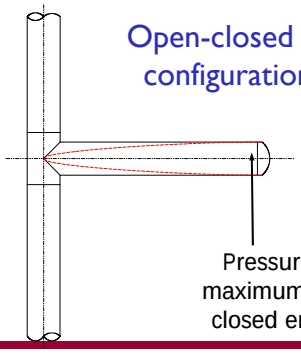
Open-Open configuration



Quarter-Wave Response

$$f = (2n-1)\frac{c}{4L}$$

Open-closed configuration



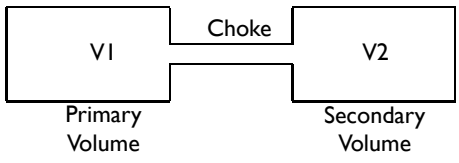
Acoustic Resonance

Natural Frequency: Helmholtz Response

$$f_H = \frac{c}{2\pi}\left(\frac{\mu}{V_1}+\frac{\mu}{V_2}\right)^{\frac{1}{2}} \qquad \mu = \frac{A}{L}$$

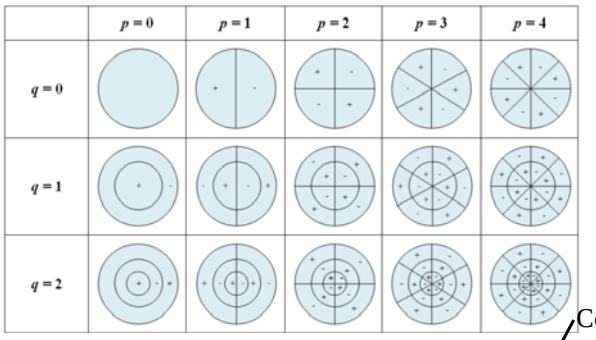
f_H = Helmholtz frequency (Hz)
c = Velocity of sound (ft/sec)
V_1 = Volume of or chamber (ft^3)
V_2 = Volume of chamber (ft^3)
A = Cross-sectional area of choke (ft^2)
L = Acoustic length of choke (ft)

Volume-Choke-Volume



Circular Duct Modes

Nodal diameters: p
Nodal circles: q



$$f = \frac{c\alpha_{pq}}{2\pi r}$$

$$r = \frac{D}{2}$$

α values are the q^{th} zero of the first derivative of the p^{th} order Bessel function [$J'_p(\alpha_{pq})=0$], which describes radial and circumferential motion.

Constants based on circular geometry

α_{pq}	p = 0	1	2	3	4
q = 0	0.000	1.841	3.054	4.201	5.318
1	3.830	5.331	6.706	8.015	9.282
2	7.016	8.536	9.969	11.346	12.682

f_{pq}	p = 0	1	2	3	4
q = 0	0.00	**332**	551	758	959
1	691	962	1210	1446	1674
2	1266	1540	1798	2047	2288

Below the cut-on frequency, only plane wave propagation exists in pipe

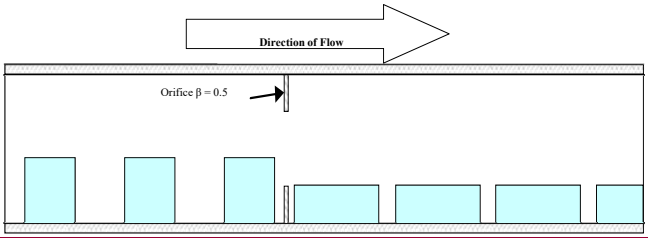
Attenuation Through Choking

Method of Attenuation

- Area ratio chokes the flow
- Pressure builds upstream of orifice
- Pressure pulse is elongated (decreased) downstream

Caveats

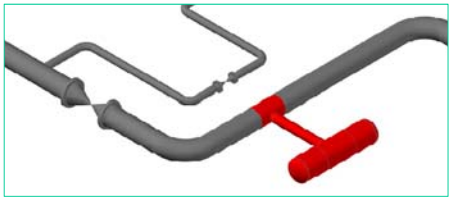
- Creates total static pressure loss
- Must be located at a pressure node
- Does not attenuate low frequencies effectively



Attenuation Through Shifting

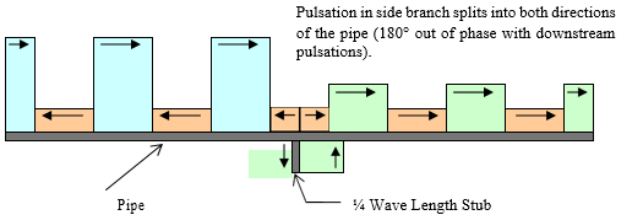
Method of Attenuation

- Portion of the flow diverted to a closed end (pipe or volume) tuned to one frequency
- Pressure pulse travels down closed end and is reflected back 180 deg out of phase with downstream pulsations to attenuate the design frequency
- Very low pressure loss



Caveats

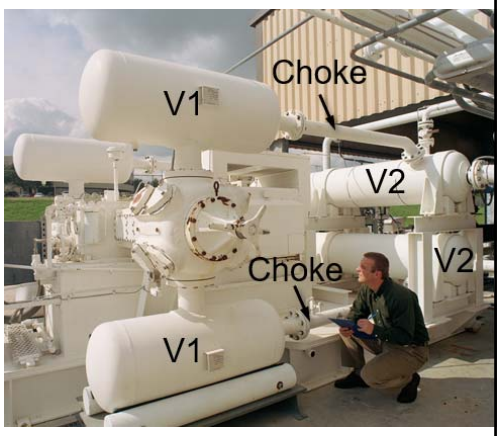
- Only works for one frequency, one per frequency
- Can be very large/long for low frequencies



Attenuation Through Damping or Filtering

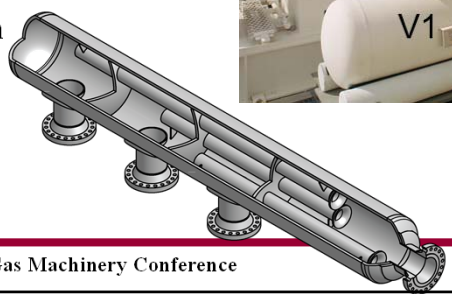
Method of Attenuation

- Large volumes damp pulsations
- Damping is most effective and practical when combined with choking
- Wide range of frequency attenuation—most effective method



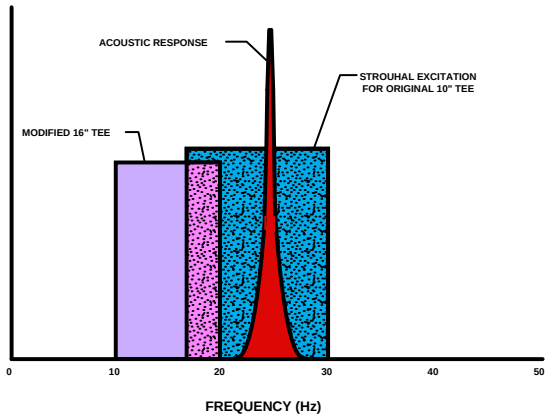
Caveats

- Typically the most expensive option
- Can be very large



Resonance Avoidance: Vortex-Shedding or Hyper Compressors

- Primarily used when excitation band is narrow
- Resonance avoidance method: a separation margin is maintained between the calculated excitation frequency and the predicted acoustic and/or mechanical natural frequencies.
- Difficult to predict the amplitude of vortex-shedding pulsations or install pulsation bottles



Pulsation Mitigation for Positive Displacement Machinery

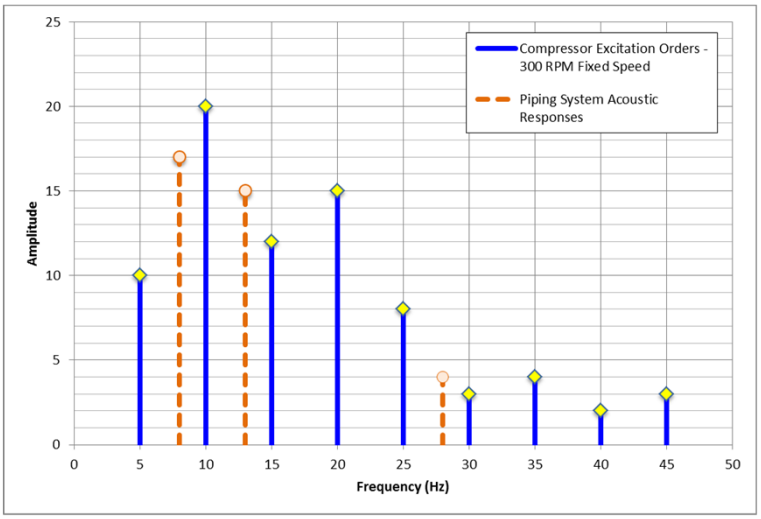
Pulsations Mitigation for Low/Med/High Pressure Machines

1. Low and Medium Pressure Machines (pressure < ~10,000 psi; lower pressure than the typical Hyper compressor)
   - Empty volumes and/or acoustic filters
   - Orifices
   - Timed Pulsation Cancelation – Side Branch Absorbers/Resonators (SBA/SBR) or PAN™
2. High Pressure Machines (pressure > ~10,000 psi; Hyper compressors)
   - Orifice plates
   - Timed Pulsation Cancelation – Cross-overs or PAN™

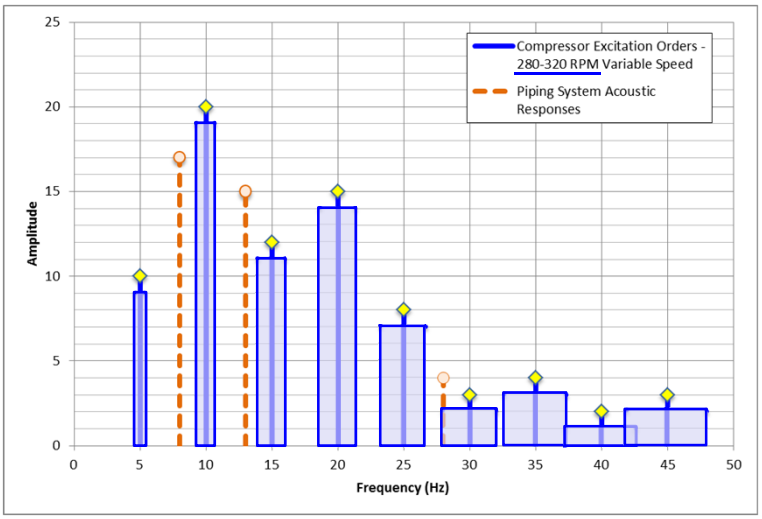
How Do We Control Acoustic Resonances?

1. Avoid acoustic resonances in the piping system, where possible
2. Install well-sized pulsation attenuation bottles
3. Install additional pulsation control devices:
   - Pulsation Damping Devices – pressure loss elements such as orifice plates
   - Acoustic Altering Devices – Side-Branch Absorbers (SBAs) or TSBA or PAN™ or cross-overs

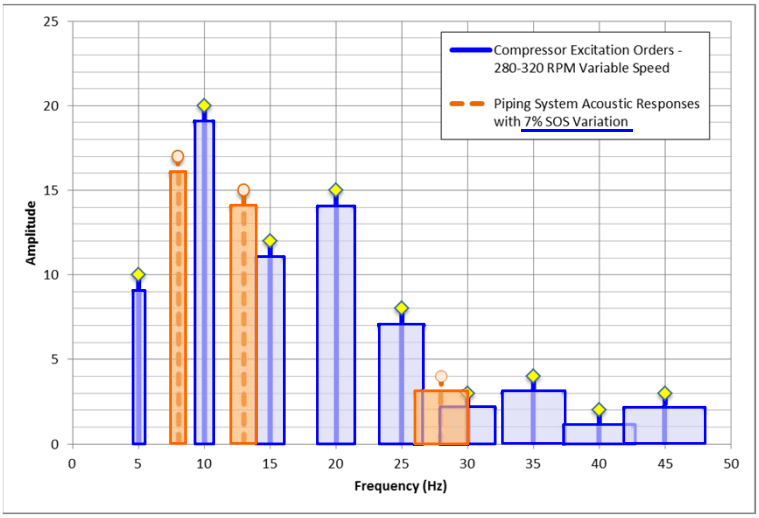
1. Avoid Acoustic Resonances



1. Avoid Acoustic Resonances

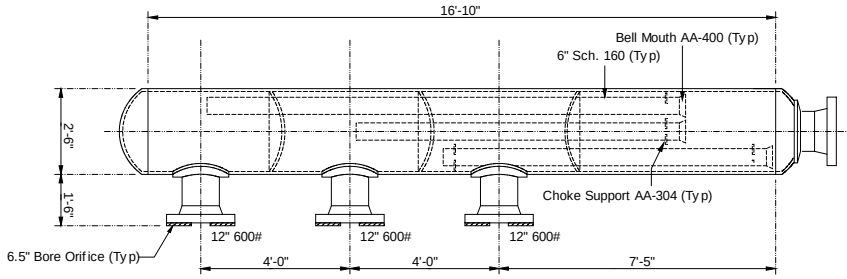


1. Avoid Acoustic Resonances



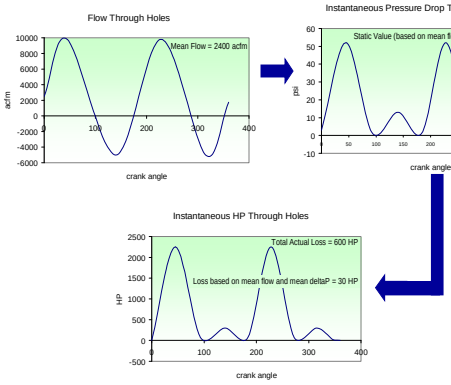
2. Install Pulsation Attenuation Bottles

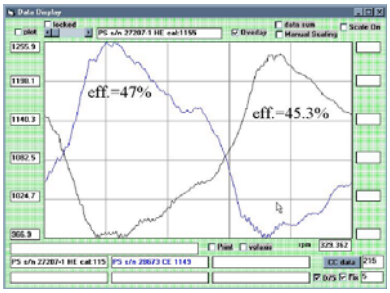
- Attenuate the acoustic Excitation Energy at higher frequencies
- Steady the flow
- Reduce Cylinder-to-Cylinder and Cylinder-to-Pipe interactions

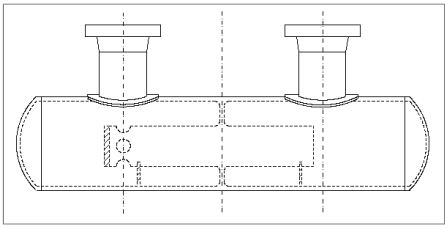


Acoustic Filter Bottle, Single-Bottle System

Why Install Adequate Pulsation Attenuation Bottles?... Consequences of Improper Bottle Design

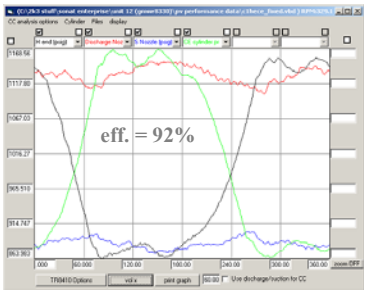


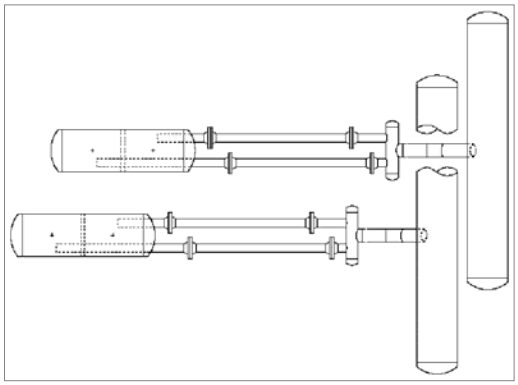




Poor performance of low speed unit in transmission service due to dynamic flow losses through the bottle caused by cylinder interactions.

Achievements of Proper Bottle Design





Improved performance by minimizing cylinder interactions and reducing dynamic flow losses through the pulsation control system.

Bottle Design Methodology

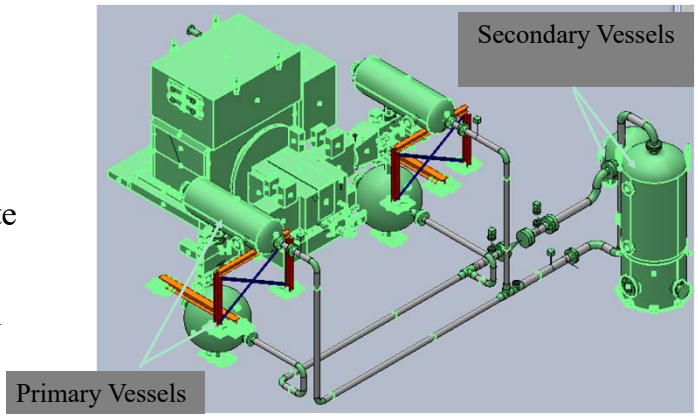
- Step 1: Determine the speed of sound variation based on gas composition, expected pressures and temperatures, and equation of state prediction
- Step 2: Select a pulsation bottle design philosophy based on:
  - Sound velocities:
    - >2,000 ft/sec (Lighter gases) ← Type 1: Empty Volume
    - ≤2,000 ft/sec (Typical Natural Gas)
  - Compressor running speed
    - ≤ 500 rpm (low speeds) ← Type 2: Two-Bottle Filter
    - >500 rpm (high speeds) ← Type 3: Single-Bottle Filter
- Step 3: Size the pulsation bottle to attenuate the excitation energy while avoiding acoustic resonances

At this point, the basic dimensions are determined but the bottle design must then be analyzed within the piping system for all acoustic and mechanical responses.

Type 1: Empty Volume
Sound Velocities >2,000 ft/sec (Lighter Gases)

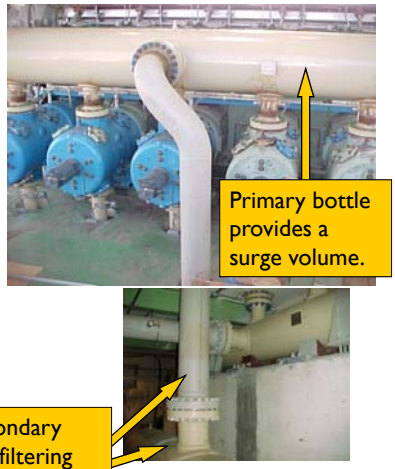
Pulsation Bottle Design

- A bottle volume of ≈20 x PD (Piston Displacement) is generally sufficient - can be refined with modeling.
- Pressure drop restrictions (orifices, line tubes, or alternate low loss technology) often located at bottle inlets and outlets for additional pulsation control.



Type 2: Two-Bottle Acoustic Filter Design
Low Speed Compressors (<500 rpm)

- Symmetry often used to minimize pass bands.
- Helmholtz frequency often placed between 1X and 2X. (Locating Helmholtz well below 1X would require larger volumes and/or smaller chokes.)
- Internal baffles and chokes often used to control bottle shaking forces and to isolate cylinders.



Type 2 & 3: Acoustic Filter Bottles
Sound Velocities ≤2,000 ft/sec (Typ. Natural Gas)

Pulsation bottle design

- Internal elements (baffles and choke tubes) often used to control shaking forces and piping pulsations
- Pressure drop restrictions (orifices) often located in the compressor nozzle for additional pulsation control

Type 2: Two-Bottle Acoustic Filter

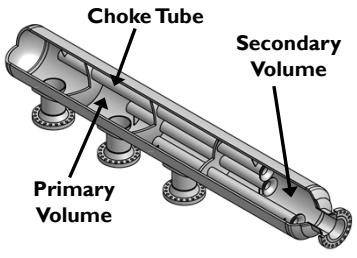
generally appropriate for speeds <500 RPM



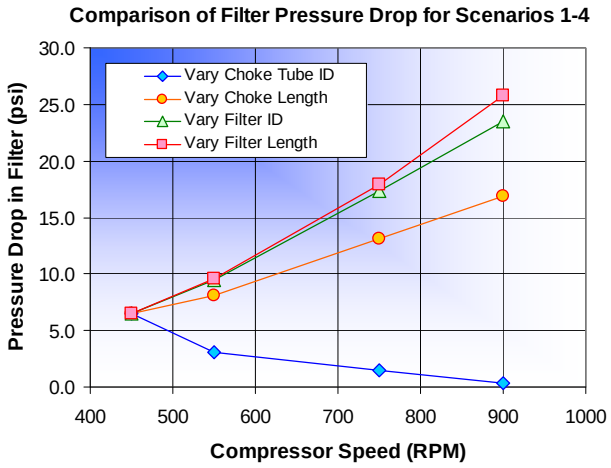
Type 3: Single-Bottle Acoustic Filter

generally appropriate for speeds >500 RPM

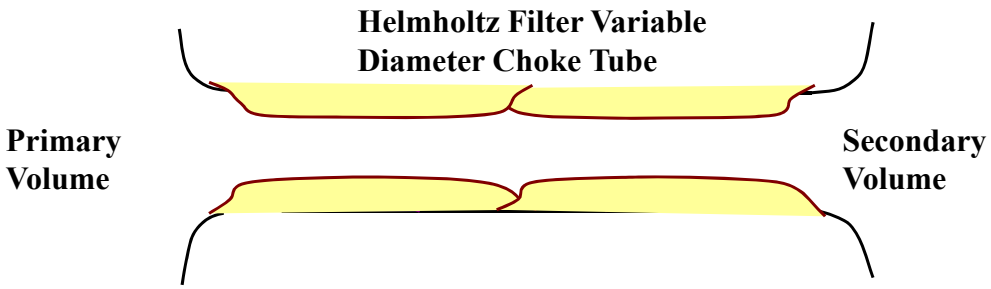




Why not a Tunable Pulsation Filter Bottle? Which Tuning Method Should be Used?



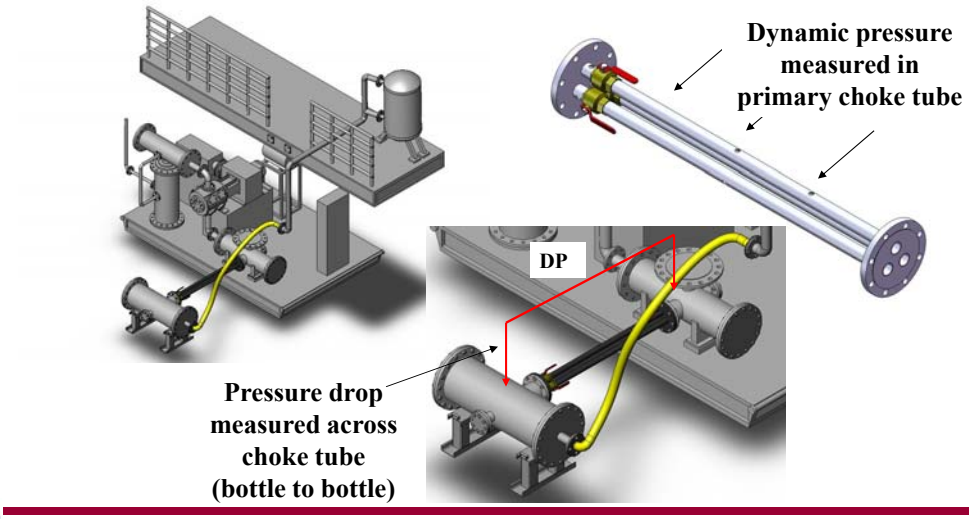
Tunable Filter Concepts after Brainstorming: Discrete Point Methods vs. Continuous Diameter Choke Tube



Continuous Diameter Method

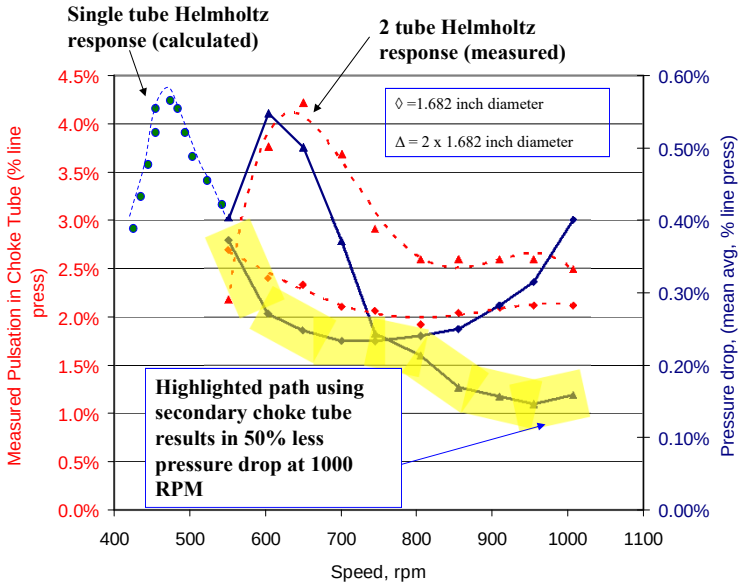
Pinch Valve Method – option

Tunable Choke Tube – Previous Testing



Tunable Choke Tube – Previous Testing (2008)

- The concept of varying the choke tube cross-section results in a significant reduction (1/3rd) in pressure drop at high flow rates with the potential of a small reduction in bottle diameter.
- The concept also allows the option of moving the response between the first and second order for cases when this is not an option with fixed, conventional designs.
  - This would allow a significant reduction in bottle diameter (potentially as much as half the bottle diameter).



VERY HIGH PRESSURE: NO VOLUMES

- Typical for hyper compressors and chemical applications
- Vessel walls become too thick and heavy
- Use combination of orifice plates and well placed acoustic natural frequencies
- Results in high pulsations in the system
  - Very robust support types
  - Thick-walled small diameter piping



Hyper Compressor Picture Courtesy of Burkhardt Compression

3. What if Additional Pulsation Control is Needed?

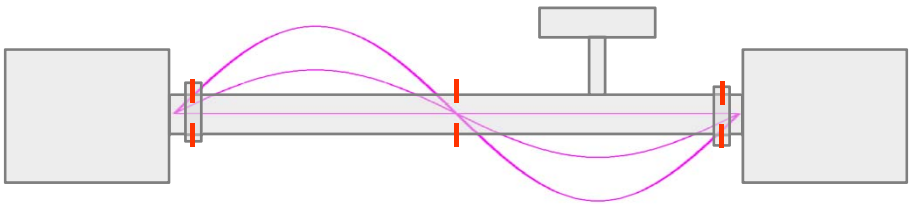
- Pressure drop restrictions (Orifices)
  - Restrict flow, add pressure loss, and *can* attenuate pulsations
  - Must be installed at the proper location (based on acoustic mode shape) to be effective
  - Most often provide pulsation damping, but do not significantly alter frequencies
  - Orifices are easy to install, but can reduce peak performance (and raise fuel consumption for the same throughput). Pressure loss increases with flow velocity squared and can be significant.
  - Cost of orifice should be carefully considered & weighted against options.
  - Orifices can increase pulsations at lower harmonics as back pressure is added to the compressor / pump

3. Other Options Beyond Bottles & Orifices?

- Side branch absorbers (SBA or Helmholtz or Quarter-wave resonator) – Low horsepower cost, but targets a small frequency range
- TSBA – Low horsepower cost & targets a larger frequency range
- Piping modifications (swages, length changes)
- Speed lockouts
- Advanced technologies (Low loss devices developed to control pulsations)
  - Pressure Recovery Insert (PRI)
  - Virtual Orifice (VO)
  - Pulsation Augmentation Network (PAN™)

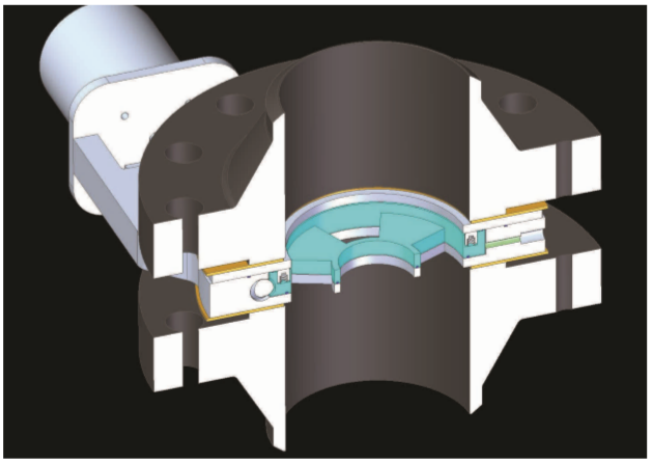
Importance of Understanding the Mode Shape to be able to Apply the Various Acoustic Tools

- The pressure pulsations mode shape is the inverse of the velocity mode shape. – Remembering this can help with the logic behind locating orifices.
- Knowing the mode shape is important to be able to alter or damp the resonance by placing an SBA, orifice, or other system modification at a location where it can be most effective/useful.



Dynamic Variable Orifice (DVO)

- Bore is variable
- If resonance on 1x, then it's probably on 2x, but not as high amplitude – DVO could be smaller when single-acting (lower flow/losses), but larger when double acting (higher flow = don't want the smaller orifice)
- If resonance at low end of speed range, but not problem at higher speed – DVO could be smaller at lower speed/flow, but larger at higher speed/flow

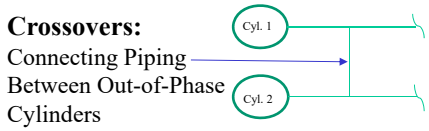


https://aciservices.com/wp-content/uploads/MKT-1244-DVO.pdf

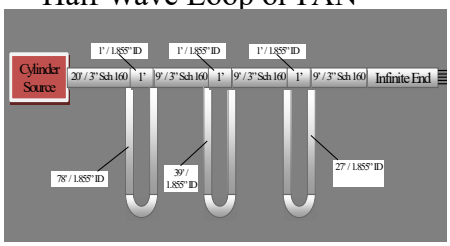
Side Branches / Crossovers / Half Wave Loops

Timed pulsation cancellation options

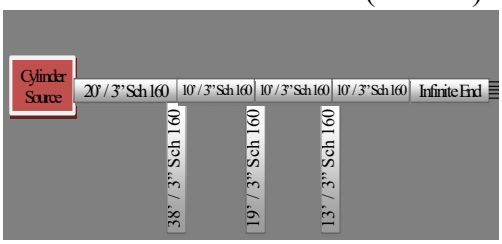
Crossovers:
Connecting Piping Between Out-of-Phase Cylinders



Half Wave Loop or PAN™*

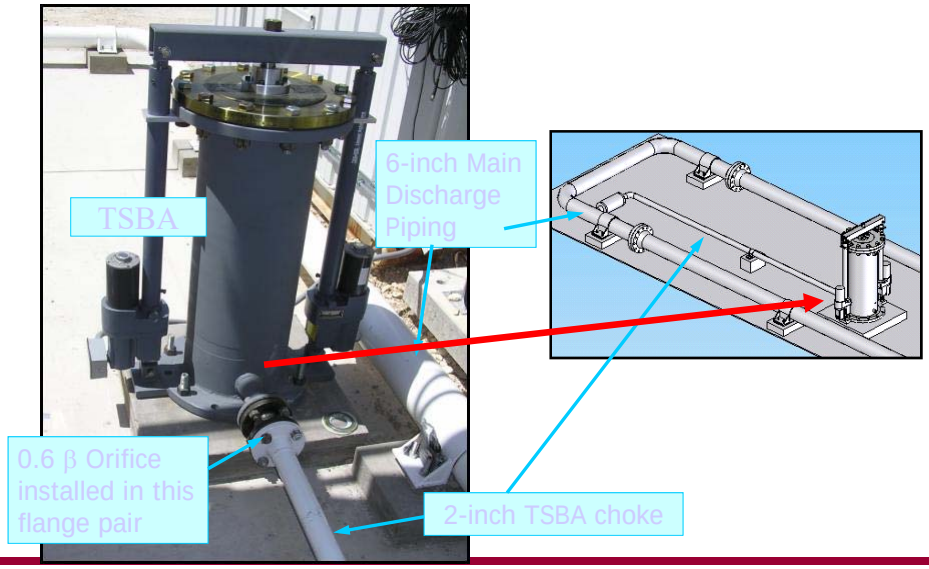


Side Branch Resonators (or SBA)

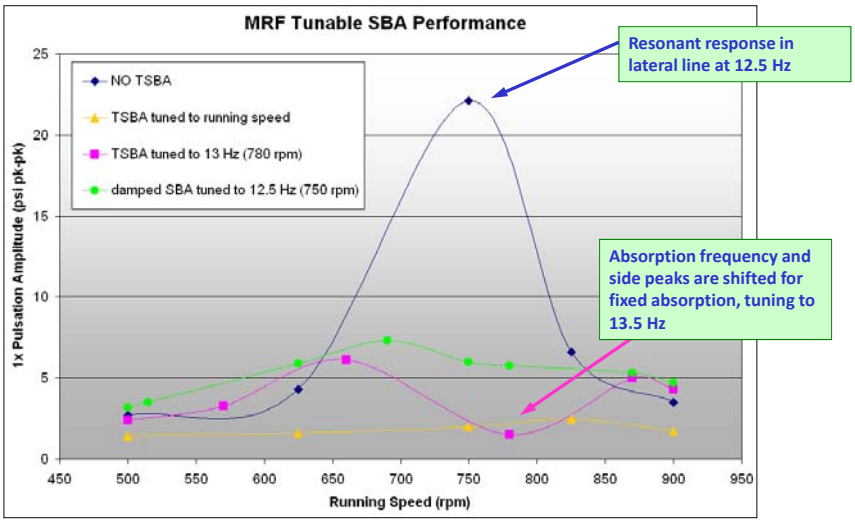


*PAN™ (Pulsation Attenuation Network) is patented by ACI Services

Tunable Side Branch Absorber (TSBA) Tested at SwRI



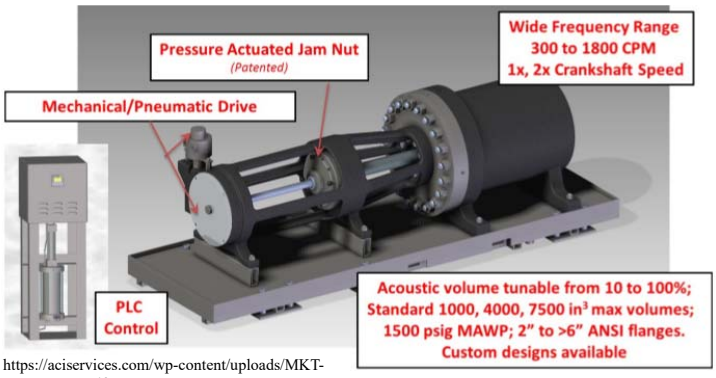
TSBA Summary (Vary Vol. Tuning)



Installation of the 0.6 β orifice in the choke tube did not improve the acoustical performance of the system.

Production TSBA by ACI Services



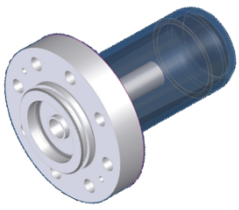


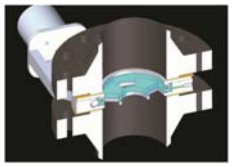
https://aciservices.com/wp-content/uploads/MKT-1243-TSBA.pdf

Addressing Nozzle Resonance – A Significant Acoustic Resonance That Should Not Be Ignored During the Bottle Design

- Typically, nozzle resonance in variable speed applications is controlled with pressure drop elements, which significantly affects compressor performance.
- State-of-the-art design tools can be used to optimize losses through orifices used to reduce nozzle pulsations.
- Technologies for controlling nozzle resonance that will minimize pressure drop (pressure recovery insert, virtual orifice) are currently available.



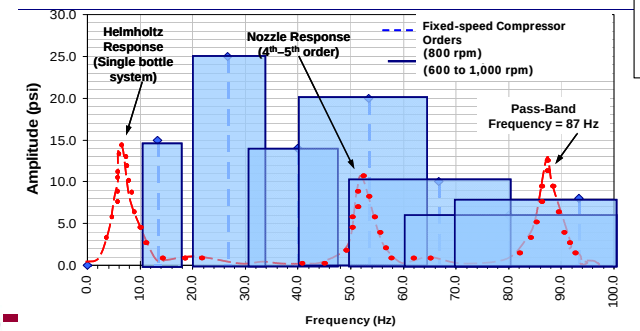




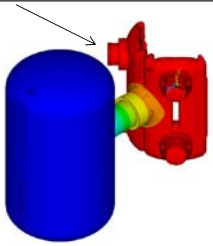
https://aciservices.com/wp-content/uploads/MKT-1244-DVO.pdf

Why Cylinder Nozzle Resonance Exists

- Variable speed, high speed compressors have very little (or non-existent) "windows" between running speeds.
- Often times, the 1-D acoustic representation of the 3-D gas passage is not well matched for accurate frequency prediction.
- NEW 3-D acoustic modal analysis can help to develop a better 1-D model.

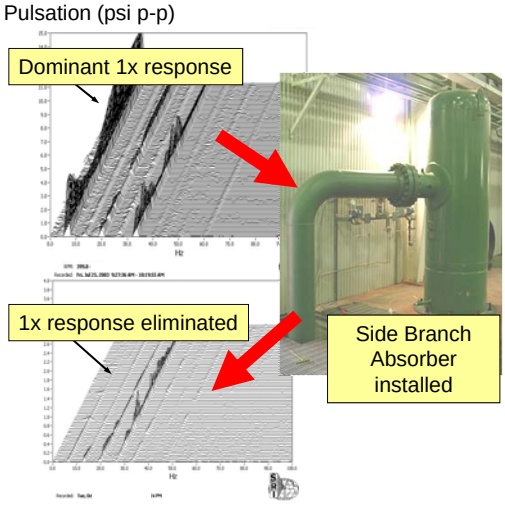


Prediction of 66 Hz "cylinder to bottle" nozzle resonance – matched field data exactly (recorded for 825-1000 RPM speed sweep.)



Concept Behind the Virtual Orifice Technology

- Use of Helmholtz resonators has been a common practice to absorb dominate frequency in piping system.
- Size of Helmholtz resonators varies according to absorption frequency, SOS, and desired effectiveness. (Low frequency = Large volumes.)
- VO technology is unique in its placement of the SBA on compressor cylinders to reduce the nozzle response, typically at 4x-6x running speed.



Basic Virtual Orifice Design



- Designed to reduce nozzle pulsations with same acoustic performance as an orifice plate (or better performance).
- Recovers pressure losses – 26-32% pressure recovery*
- Efficiency Improvement – 3-9% efficiency improvement*
- Installed in place of a cylinder valve cap.
- Size varies based on cylinder size and operating conditions.

* As compared with the losses of a typically sized cylinder nozzle orifice plate

Virtual Orifice Field Test – Initiated in October 2007

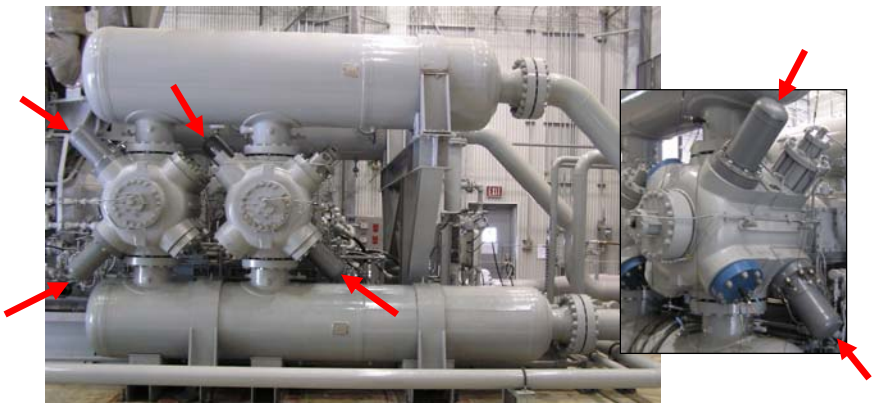
- Installed on suction side of two cylinder Superior MH62 unit at El Paso Baxter Station in Rocksprings, WY.
- Issues prior to VO installation: Vibrations and nozzle failures in the suction bottle due to lack of clamps and cylinder nozzle resonance. Initially, a typical orifice was used to mitigate the effects of high nozzle pulsations.
- VO reduced vibrations significantly and improved horsepower consumption.



VO primary vessel diameter = 5.56" with overall length = 14.75"

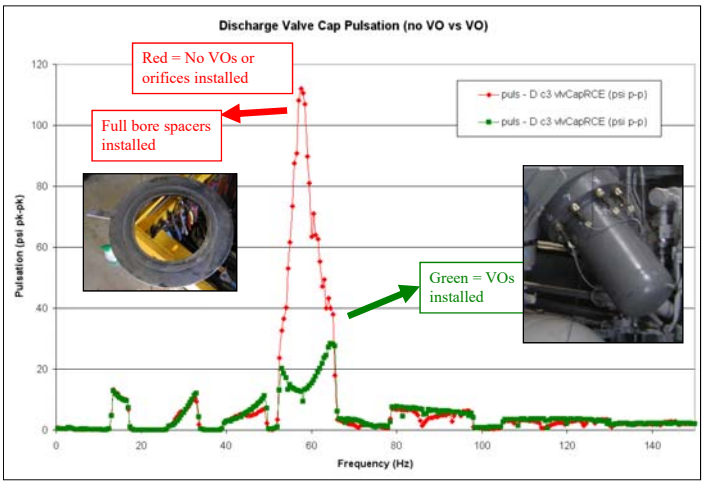
VO Field Testing at Boardwalk Pipeline Destin Station

- **Objective:** To further develop and verify performance of the VO through field testing. Testing to evaluate reliability, mechanical responses, material considerations, and performance.
- Compressor Specifications: Ariel JGC/4, 790-1000 rpm, ~950 to 1080 psig suction pressure, ~1090-1210 psig discharge pressure, all cylinders can SA



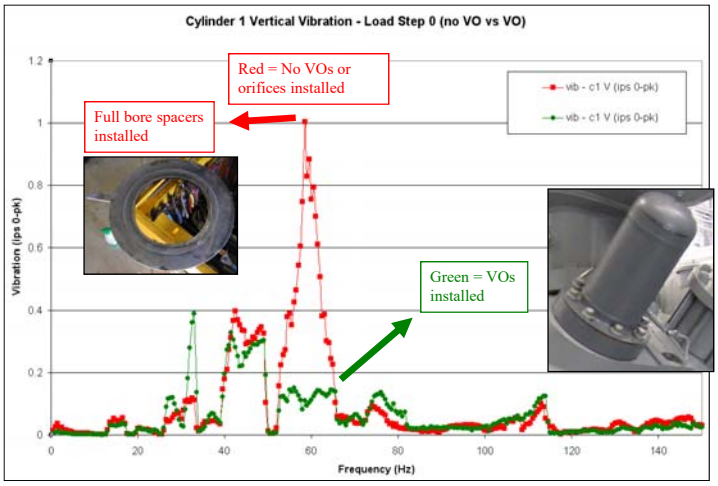
VO – Destin Field Testing – Measured Pulsation Data (Discharge)

Similar results were observed on the suction side.

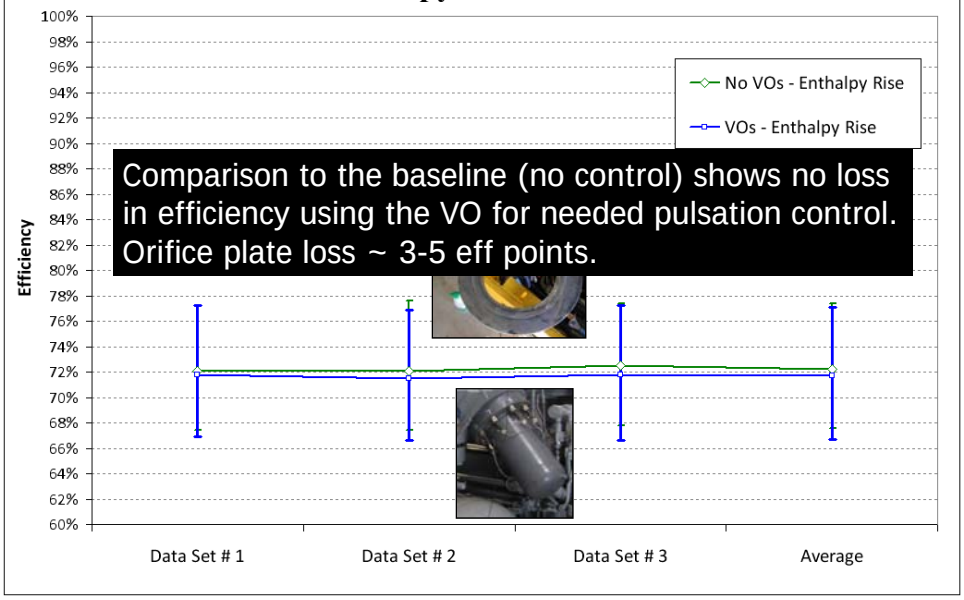


VO – Destin Field Testing – Measured Vibration Data (Vertical)

Similar (but less significant) results were observed in the horizontal direction.



Measured Enthalpy Rise Performance Data



Comparison to the baseline (no control) shows no loss in efficiency using the VO for needed pulsation control. Orifice plate loss ~ 3-5 eff points.

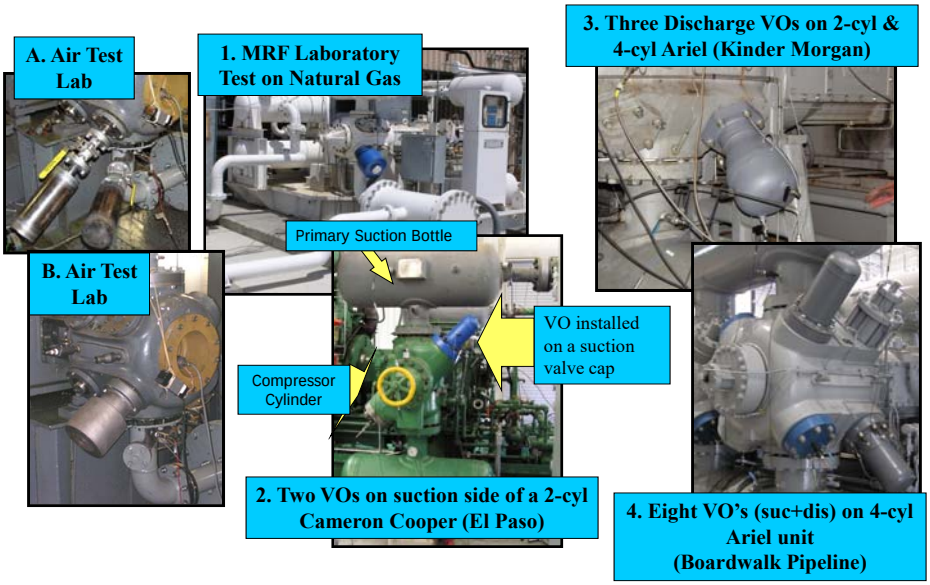
VO – Destin Field Testing – Summary

- Cylinder Valve Cap Pulsation Improvement:
  - Suction: 64% (83% at the initial resonance)
  - Discharge: 73% (86% at the initial resonance)
- Cylinder Vibration Improvement:
  - Vertical: 60% (85% at the initial resonance)
  - Horizontal: 16% (77% at the initial resonance)
- Performance Changes – When the VOs were installed (compared with no control):
  - PV Card Measurements indicated comparable performance.
  - Enthalpy Rise measurements indicated only a 0.5% efficiency reduction. *
  - hp/MMSCFD comparisons indicated a 3% improvement

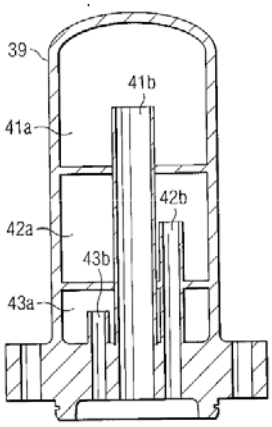
* The measured values were statistically equal when considering the uncertainties associated with the measurements.

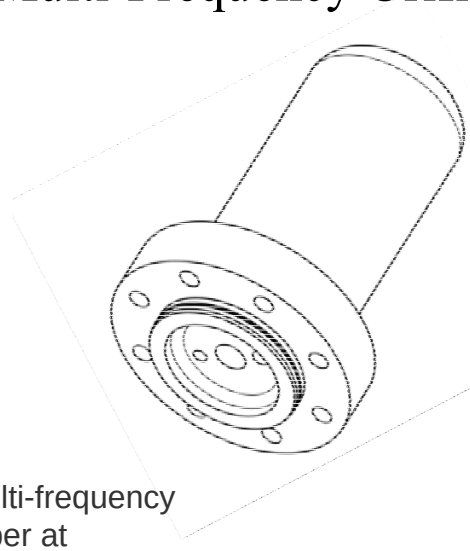
Verified System Changes That Resulted From the Installation of VOs

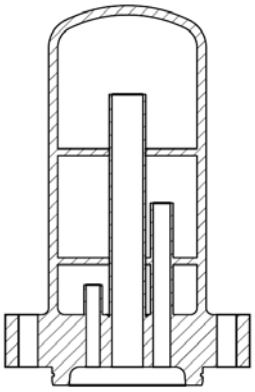
VO Fabrication Record



M-FOR – Multi-Frequency Orifice Replacement







Patent title: "Multi-frequency pulsation absorber at cylinder valve cap"

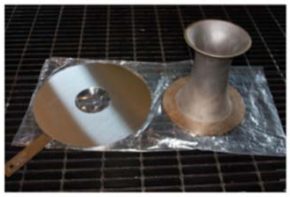
The Pressure Recovery Insert (PRI) Nozzle



- Designed to provide same or better pulsation control as an orifice plate, using a reduction is cross-sectional area to attenuate high pressure peaks.
- Pressure recovery is achieved because of gradual changes in area expansion and contraction
- Less pressure loss, which results in less power lost and reduced fuel cost
- Engineered using CFD studies and test data to provide optimal pulsation reduction at very low pressure drop penalty
- Can be made to fit full-range of pipe sizes and in discharge or suction configurations

Installation of PRI Suction Nozzle at El Paso Elk Basin Station

Orifice vs Nozzle Insert







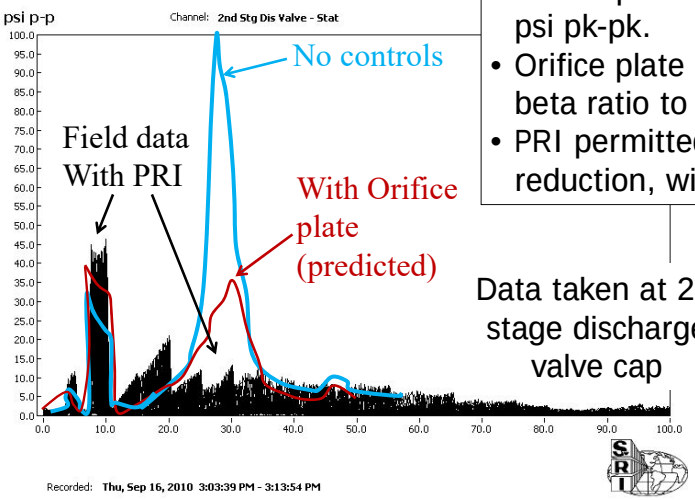
Nozzle Insert & Gasket





*Successful operation since August 2009.

Nozzle Pulsations on 2nd Stage Discharge – Fully Load, Single Stage Operation



- Nozzle pulsations with no control at 100 psi pk-pk.
- Orifice plate DP requirements limited beta ratio to 0.75.
- PRI permitted optimal nozzle pulsation reduction, with less DP.

Data taken at 2nd stage discharge valve cap

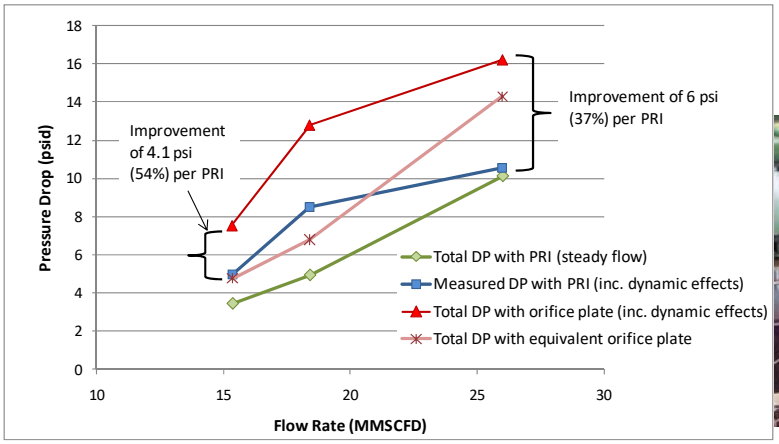
PRI Field data shown in black

In blue = Model data: Baseline nozzle response prediction (no control in place)

In red = Model data: Nozzle response with Beta 0.75 orifice plate

PRI Summary Pressure Loss Data

- SwRI analyzed two stage operation with highest flow rates (30-52 MMSCFD) over speed range of 230-300 RPM.
- Measured DP for PRI included dynamic effects and elbow, tee losses between taps.
- PRI showed 37-54% less pressure drop than equivalent orifice plate. (Equivalency based on similar pulsation control.)





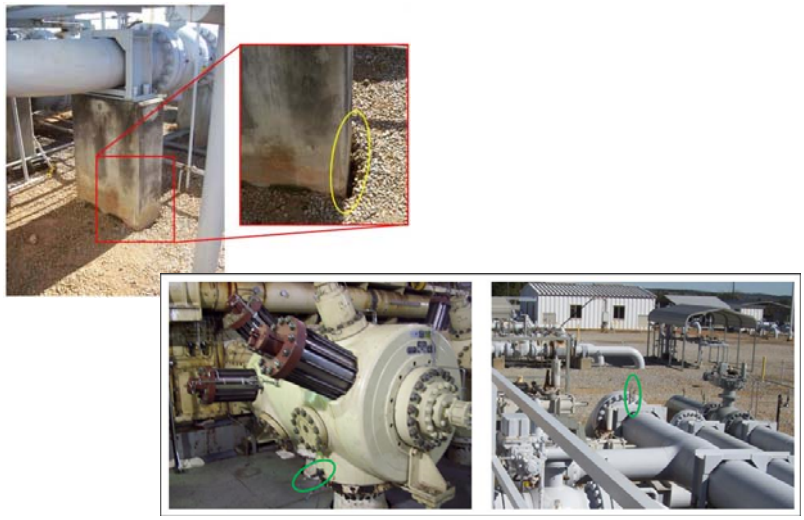
Advanced Pulsation Control Conclusions

- Tunable Filter Bottle – Pulsations controlled + improved efficiency over the entire speed range
- DVO (Dynamic Variable Orifice) – Can be a significant system efficiency improvement
- PAN (Pulsation Augmentation Network) – Similar to a network of SBA's, but flow-through device
- TSBA (Tunable Side Branch Absorber) – Better than SBA, it's tunable!
- VO (Virtual Orifice) – controls vibration and pulsation in cylinder nozzles through absorption of primary frequency band – No efficiency penalty
- M-FOR (Multi-Frequency Orifice Replacement) – VO with additional pulsation frequency absorption capabilities
- PRI (Pressure Recovery Insert) – PRI offers ability to control nozzle pulsations through attenuation, at lower DP cost than orifice plate.

- 6 of the 7 devices have been field tested
- All devices, when properly designed and implemented, produce significant efficiency and pulsation attenuation improvements

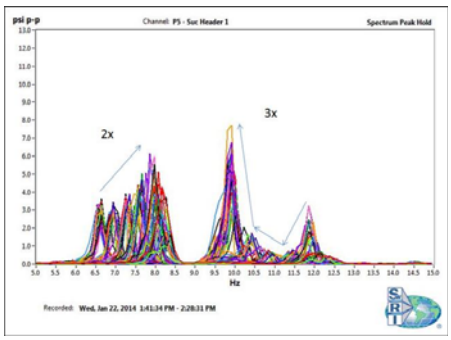
Effect of Changing Operating Conditions: Case History

- Pipeline gas compression facility reported excessive vibrations
  - Variable speed reciprocating compressors 200-250 rpm (3.3-4.2 Hz) swept data in 10 rpm (0.2 Hz) increments
- Levels of vibration visibly high in yard piping during previous summer of operation
  - Vibrations developed after recent changes of this piping
  - Current testing done in spring



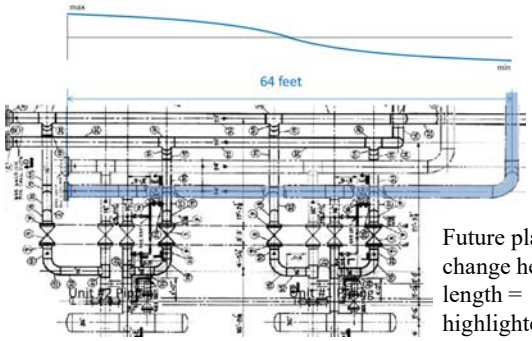
Effect of Changing Operating Conditions : Results – Pressure Measurements

- Significant increase in pulsations at suction header end near bottom of 3x
- Difference of 20°F would increase SOS



Shape of pulsations suggest acoustic resonance between 8 and 10 Hz

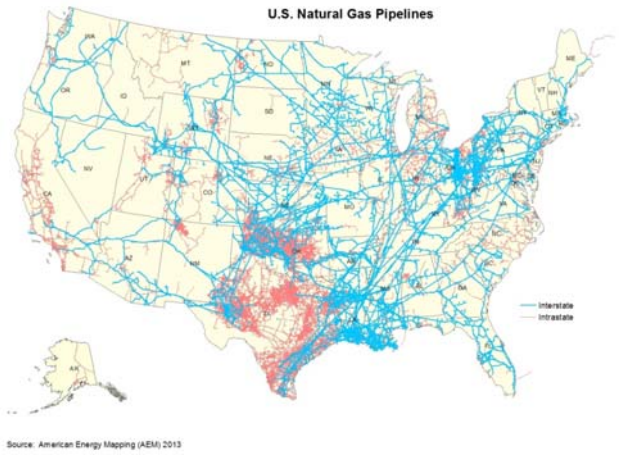
- Acoustic length response of main suction header
- Pulsation force could exceed 3,000 lbf p-p at each end
- Potentially > 12,000 lbf p-p with 0.25 Hz ANF shift



Future plans to change header length = highlighted need for pulsation study

Flow Reversal and/or Gas Change

- Natural gas boom has created a demand for gas flow in different directions.
  - New well productions
  - Higher demand in geographical areas
  - New interconnects throughout piping system
- Many of the stations are built to flow in one direction.
  - Gulf of Mexico stations typically designed to flow North
  - Northern regions now have large quantities of gas entering the pipeline.



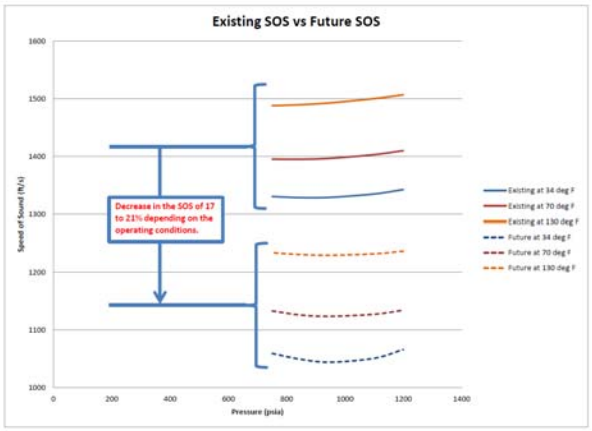
Flow Reversal and/or Gas Change

- Many stations have operated at the same conditions for decades with no vibration issues.
  - Initial design conditions:
    e.g. gas composition, pressures
  - Station requirements:
    e.g. flowrates, discharge pressures
- Updates to station equipment might coincide with flow reversal project.
  - Gas scrubbers
  - Piping and valve additions

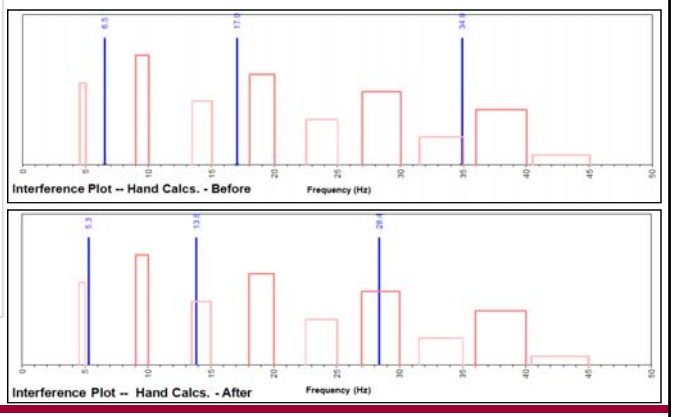
Existing recip. compressor station planning to operate with new shale gas

	Existing	Future
	% mol	%mol
CO2	0.958	1.761
Nitrogen	0.347	0.081
Methane	97.909	77.947
Ethane	0.494	11.782
Propane	0.19	4.718
Iso-Butane	0.036	1.167
N-Butane	0.042	1.35
Iso-Pentane	0.01	0.523
N-Pentane	0.007	0.34
N-Hexane	0.007	0.248
N-HEPTANE	0	0.052
N-OCTANE	0	0.011
N-NONANE	0	0.001
BENZENE	0	0.002
METHYLBENZENE	0	0.002
Molecular Weight	16.511	21.288

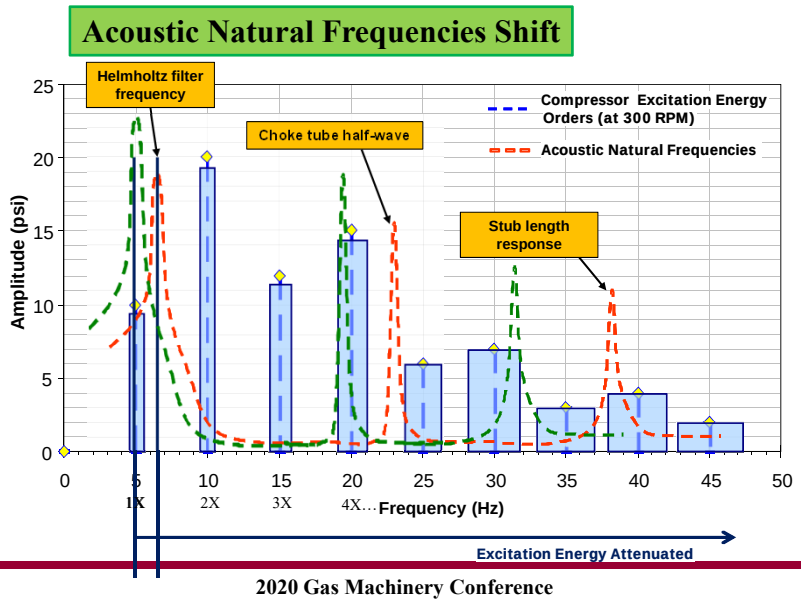
Change of Gas Composition Means Change of Speed of Sound (SOS)



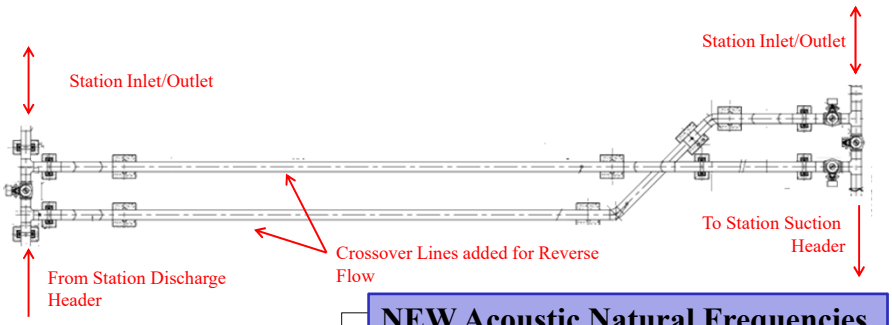
- SOS (per gas composition on the previous slide) decreased 17-21%
- % SOS shifts = % ANF shifts



Acoustic Design Consideration

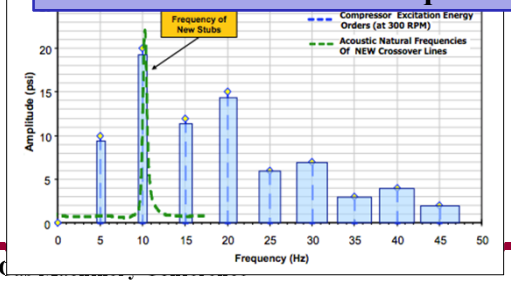


Acoustic Design Consideration



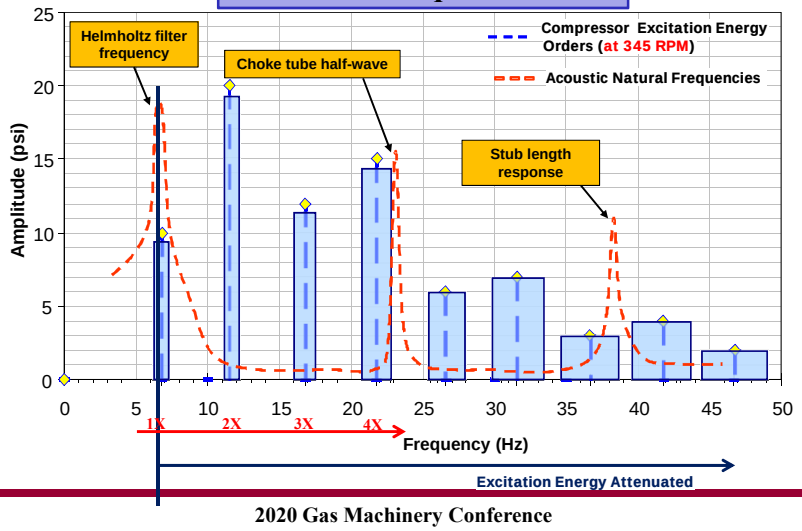
$$f_n = n\frac{c}{4L}$$

NEW Acoustic Natural Frequencies



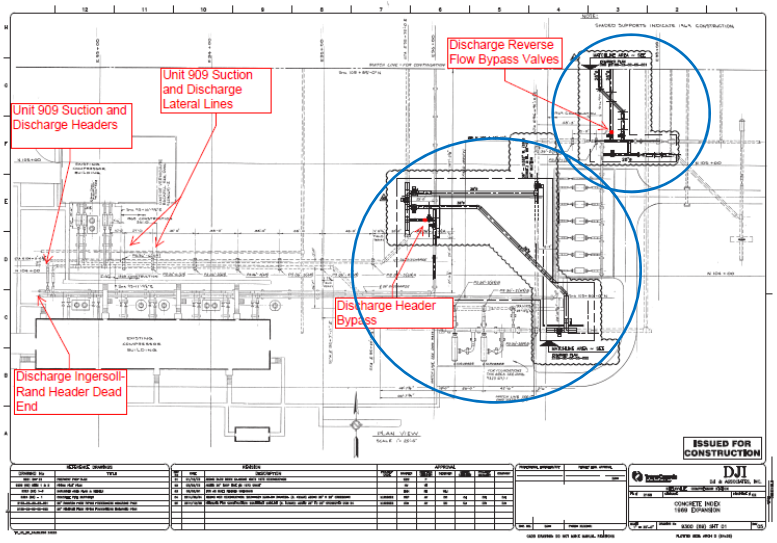
Acoustic Design Consideration

Excitation Frequencies Shift



Flow Reversal Case Study

- TransCanada transmission station
- Station experienced high vibration when reverse flow lines added and while operating in reverse flow mode.
- Original study performed in 1970 – no plans for reverse flow 45+ yrs later

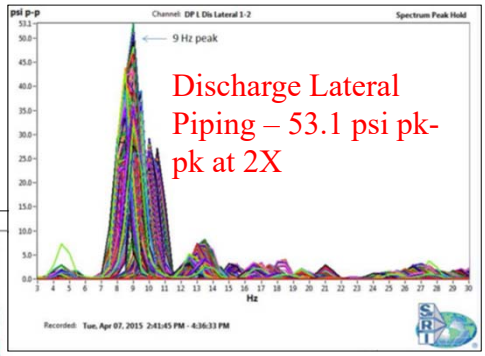


Flow Reversal Case Study – Acoustic Design

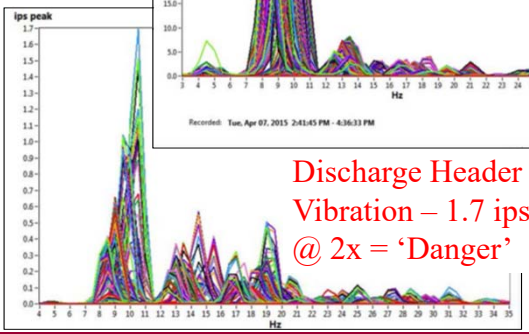
- Data collected on suction and discharge bottles, laterals, and header piping system.







Discharge Lateral Piping – 53.1 psi pk-pk at 2X

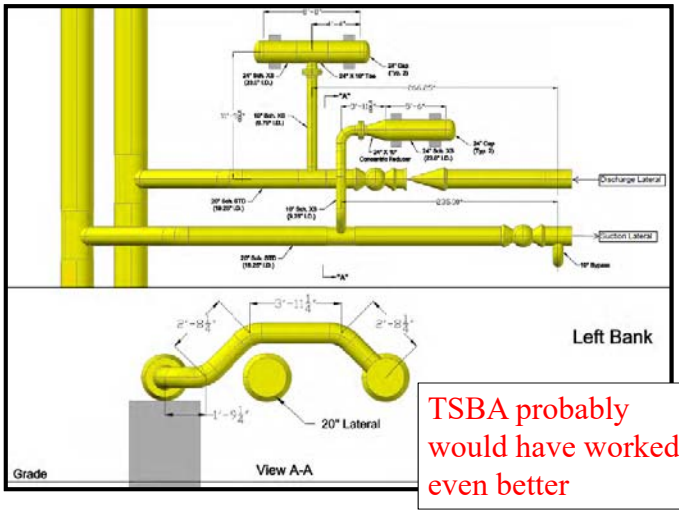


Discharge Header Vibration – 1.7 ips 0-pk @ 2x = 'Danger'

1.7 ips 0-pk vibration data also collected on the valves implemented for reverse flow.

Flow Reversal Case Study – Recommendations for the Left Bank (similar for Right Bank of compressor)

- Possible modifications included:
  - Multiple orifice plate locations
  - Modify existing pulsation bottles in order to filter 2X running speed.
    - Would have needed to add approximately 30 to 40 feet to the bottles.
  - Add additional secondary pulsation bottles.
  - Side branch absorbers (SBAs) tuned to 2X running speed.
- An updated acoustical analysis should be performed prior to operation in reverse flow



TSBA probably would have worked even better

Pump Poll Question (Poll #2)

Pumps – Dampener/Volume or Filter

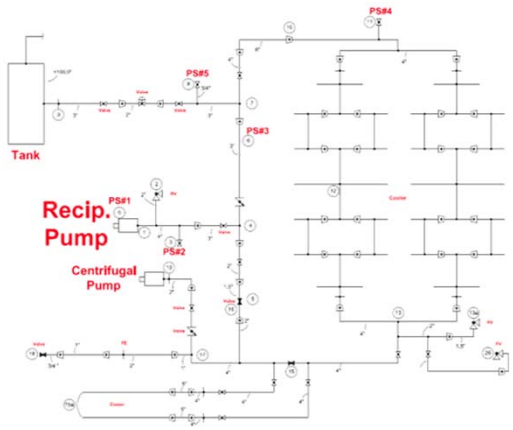
- Case study where dampener caused pulsation problem
- Case study for Filter

CASE STUDY: ON-SITE PROBLEMS— POSITIVE DISPLACEMENT PUMP

- High suction piping vibration causing:
  - Pipe insulation deterioration
  - Pipe restraint damage
  - Shortened pump valve life
  - High noise
- Gas-liquid pulsation dampeners installed years prior to field study – removed due to high maintenance and frequent bladder failures
- Issues above raised safety & reliability concerns

ALL-LIQUID ACOUSTIC DAMPENER – PUMP DESCRIPTION DETAILS

Pump Operating Conditions
30-40 psig (2.1-2.8 barg) Suction Pressure
1000-1250 psig (69-86 barg) Discharge Pressure
210-230°F (99-110°C)



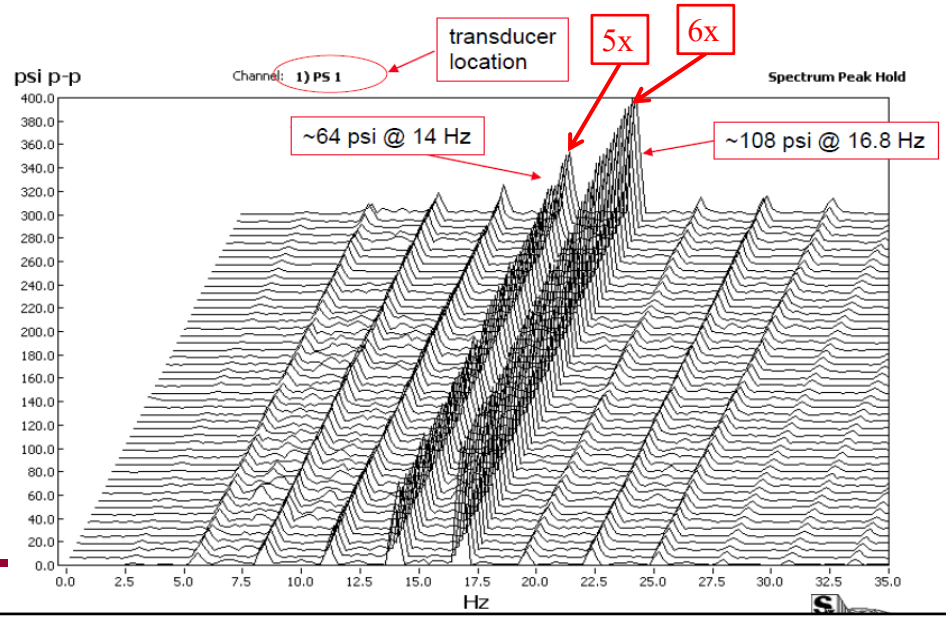
Pumps Details
2 pumps (plunger) Separate piping systems
3 plungers per pump
3.375” bore (8.57 cm)
5” stroke (12.7 cm)
166 rpm

SUMMARY OF FIELD MEASURED PULSATION

Test Point	Overall Amplitude psi pk-pk	Shaking Force lb_f p-p	3x 8.4 Hz psi p-p	5x 14 Hz psi p-p	6x 16.8 Hz psi p-p	~10x 25 Hz psi p-p
PS 1	110	1749	22	64	108	--
PS 2	143	1820	19	60	96	--
PS 3	---------- No signal ----------					
PS 4	45	573	15	--	95	--
PS 5	80	591	11	--	17	24 / 25

Indicates potential of failed valves

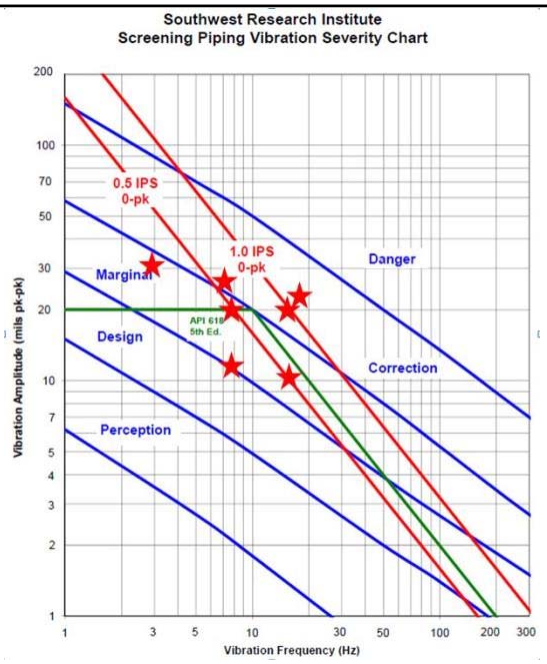
FIELD PULSATION DATA AT PUMP



FIELD VIBRATIONS ON VIBRATION GUIDELINE CHART

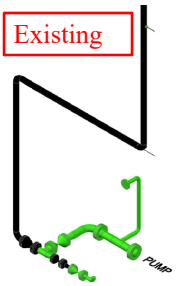
Field measured vibrations in "Marginal" and "Correction" regions

High vibrations coincided with frequency of high pulsations



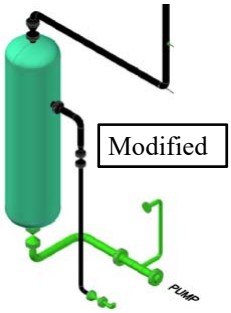
PULSATION ANALYSIS/MODELING MODIFIED SYSTEM

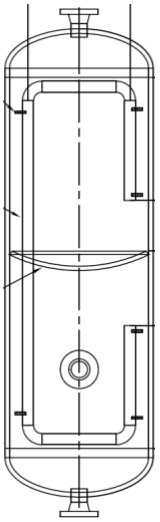
Existing

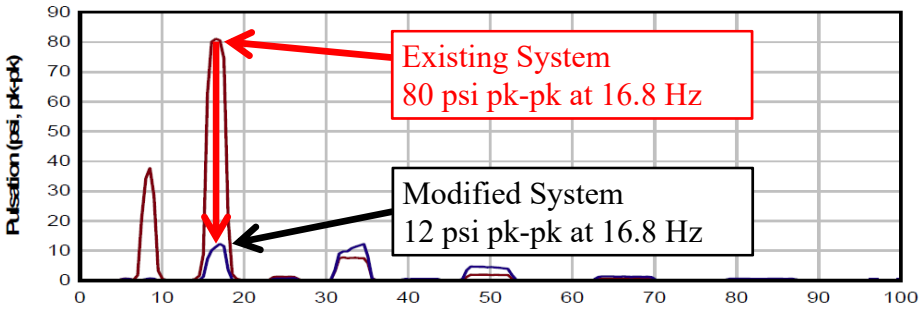


Much lower amplitude pulsations predicted

- Pump manifold (see below)
- Upstream piping 0.1-12 psi pk-pk at 16.8 Hz







VIBRATION MEASURED WITH FILTER INSTALLED

Test Point	Before 3x 8.4 Hz (mils p-p)	After 3x 8.4 Hz (mils p-p)
FV	76	0.73
Pump Suction	34	0.37
Pump Discharge	33	1.25

- Data measured by operating company
- Highest vibration with filter = 1.84 mils pk-pk at 9x

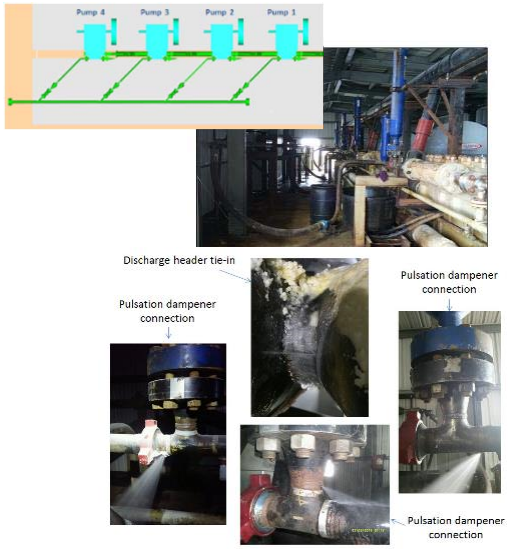
The following is a quote from the client: "Operators saying they have to walk up and touch the motor to make sure it's running, whereas they could hear the pump from the road before the change."

Pump Acoustic Filter Case Study – SUMMARY AND LESSONS LEARNED

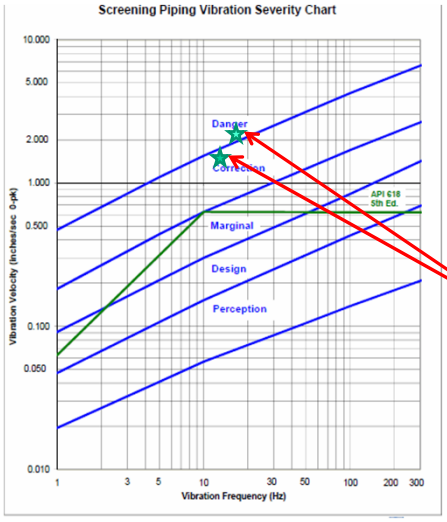
- Pump System Problem
  - High amplitude piping vibrations – insulation and restraint damage
  - Gas-liquid dampener bladder failures
- Steps taken to Solve Problem
  - Field investigation for problem evaluation – vibration & pulsation data measured
  - Pulsation analysis
- Summary & Lessons Learned
  - Well designed acoustic dampener significantly reduces system pulsations, which results in reduced vibration amplitudes

CASE STUDY, Pump System: Gas-Liquid Dampeners

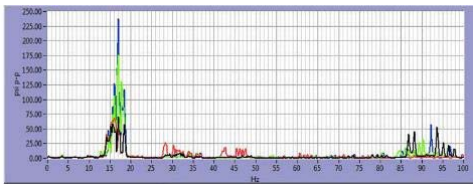
- Four positive displacement quintuplex pumps
- Each pump had dampener installed on discharge line
- Pumps connect to discharge header with flexible lines
- Problems:
  - Numerous failures in piping near pulsation dampeners and at discharge header tie-ins
  - Visibly high levels of vibrations on piping
  - Elevated audible noise



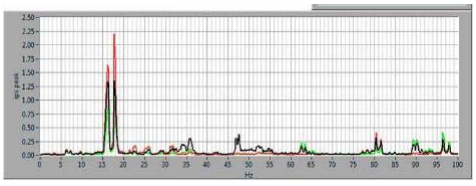
FIELD DATA: DISCHARGE VIBRATION RESUTING FROM PULSATION



Field Data pulsation at 16 - 18 Hz

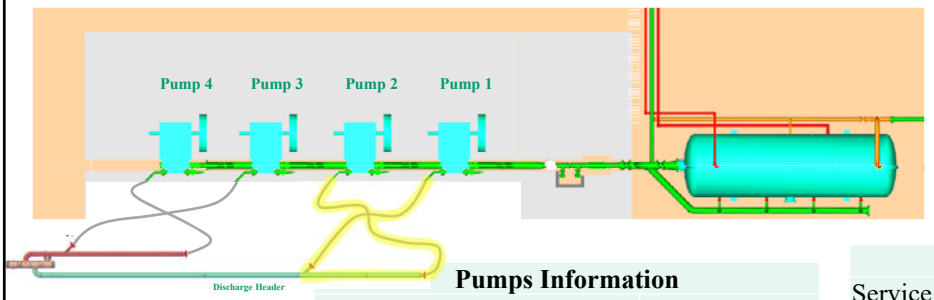


Field Data vibration at 16 - 18 Hz



Field data indicated vibration due to high pulsation levels (acoustic source)

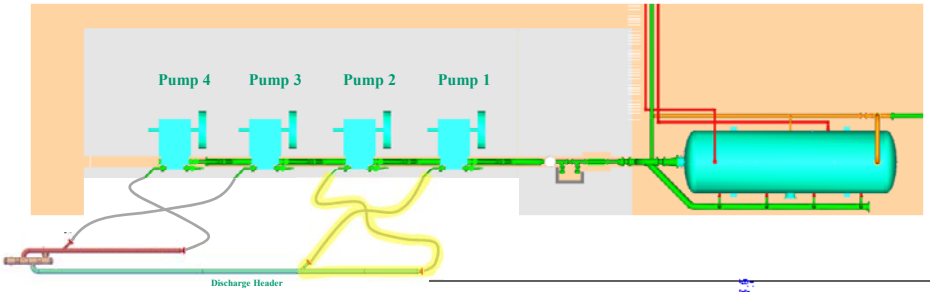
Pulsation/Acoustic Analysis – Model Details



Pumps Information	
Number of Pumps	4
Number of Stages	1
Number of Plungers	5
Pump Speed (rpm)	143-286
Plunger Diameter (in)	2.625
Stroke (in)	7
Capacity at max speed (gpm)	235
Rated Horsepower (BHP)	625

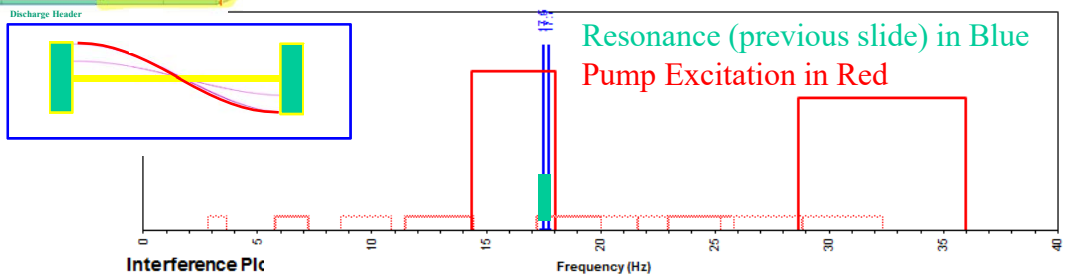
Fluid Information	
Service - Type of Fluid	Well Injection Oil
Suction Pressure (psig)	40
Discharge Pressure (psig)	~1000-3900
Temperature (°F)	110
Specific Gravity	~2.8

System Acoustic Natural Frequency (ANF)



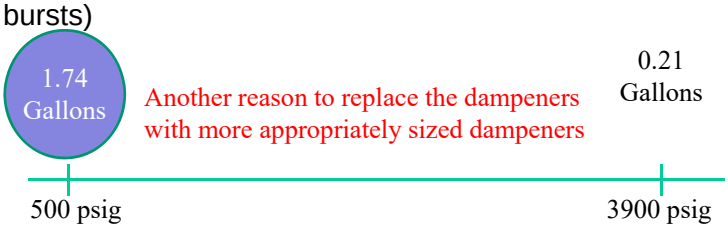
$$f_n = \frac{c}{2\pi}\sqrt{\frac{\mu}{V_1}+\frac{\mu}{V_2}}$$

$$\mu = \frac{A_c}{L_c}$$



Pulsation Analysis – Dampener Size

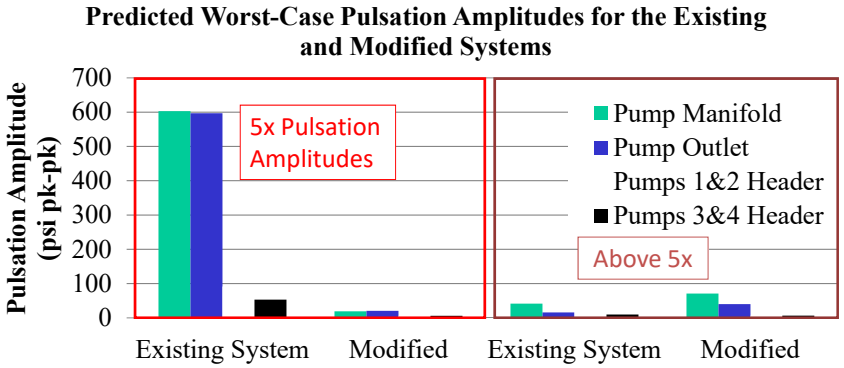
- Pre-charged original dampener to only 500 psi (MAX)
  - Gas volume decreases at higher pressures (per ideal gas law)
  - 1.74 gallon gas volume at 500 psig becomes 0.21 gallon gas volume when line pressure reaches 3900 psig (or it bursts)



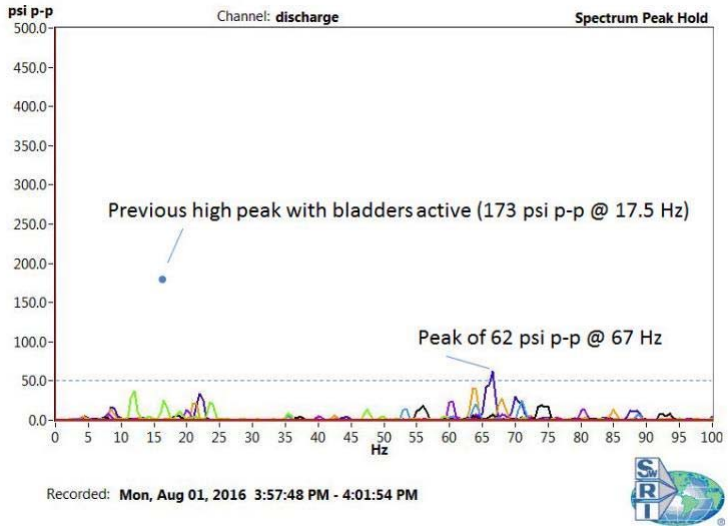
Pulsation Analysis – Before/After Predictions

Recommendation - 2.5 gallon dampeners in same location

- Sufficient surge volume at max pressure (when properly pre-charged)
- Sufficient volume to shift acoustic natural frequency down to below 5x



Pump Dampeners Cause Resonance Case Study: Post-Modification Testing



- Pulsations significantly reduced with modifications
- Audible noise and visual vibrations also reduced per station personnel
- Station has been running without incident since modifications in 2016.

Acoustic/Pulsation Attenuation Summary

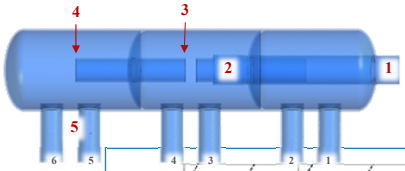
- Avoid acoustic resonances in the piping system, where possible
- Installing well-sized pulsation attenuation bottles/dampeners is the next best solution for resonance management
- Manifold design must balance pulsation/vibration control and compressor performance and mechanical considerations
- When installing additional pulsation control devices, such as orifices, DVO, SBA, TSBA, PAN, VO, M-FOR, PRI, etc., it is important to understand the system acoustics and how it will interact with the pulsation signature of the PD machinery
- Consider revisiting pulsation analysis when gas comp. changes

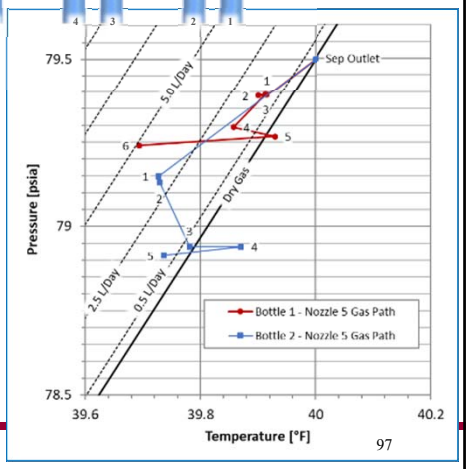
Break

Advanced Topics in Pulsation

Wet Gas Considerations

- Pulsating flow and pulsation control systems can move the operating point of the gas resulting in liquid drop-out
  - Pulsations create large changes in pressure
  - Pressure losses create heat losses
- Even small amounts of drop-out can result in significant ingestion of liquid into the compressor
- Problems with liquid accumulation:
  - Filling cylinder end cap resulting in pressure spikes
  - Decrease the effectiveness of the pulsation bottle if not regularly drained
  - Slugging





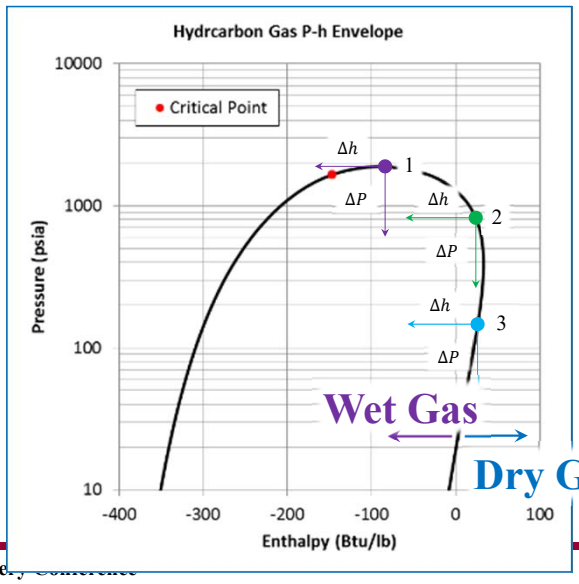
For a saturated gas, will pressure and heat losses result in liquid dropout?

Depending on operating conditions, pressure losses, heat losses, or both can result in condensation.

Operating Point 1: pressure losses move operating point into the wet gas (two-phase) region

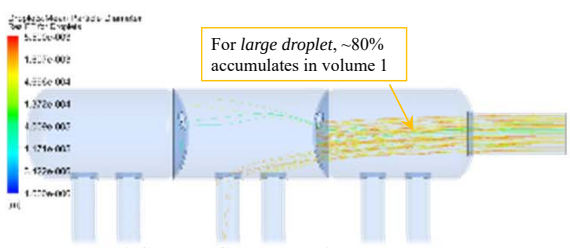
Operating Point 2: both pressure and heat losses move operating point into the wet gas region

Operating Point 3: heat loss moves operating point into the wet gas region, pressure loss moves into superheated region

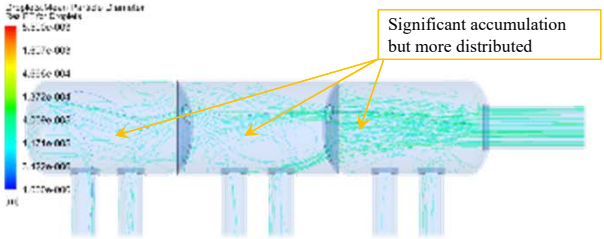


Does It Accumulate: Where and How Much?

- A 1-D screening analysis can be performed in HYSYS enabled pulsation analysis to evaluate whether the dewpoint will be crossed as the gas travels through the piping system and pulsation control system
- A 3-D CFD analysis can be performed to qualitatively and quantitatively compare bottle designs, patters of liquid dropout or liquid distribution



Bottle 1 Steady State Particle Track - Large Droplet



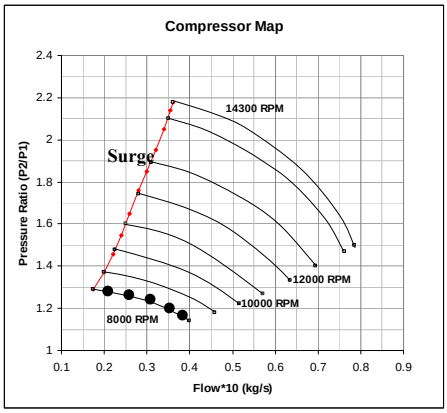
Bottle 1 Steady State Particle Track - Small Droplet

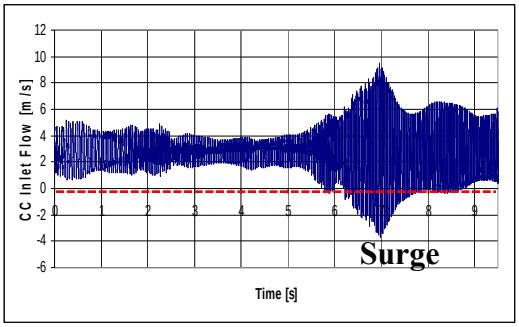
PULSATION INTERACTION IN MIXED COMPRESSION

When reciprocating compressors share common headers with centrifugal compressors, pressure and flow pulsations can severely reduce the centrifugal compressor's surge margin and operating range.

- Low frequency pulsations less than 50 Hz do not decay quickly—it is not sufficient to separate the compressors by several hundred feet of piping.
- Lateral piping of centrifugal compressor can experience severe vibrations
- Pulsating flow requires more horsepower to compress resulting in centrifugal compressor performance degradation
- Pulsations create flow velocity fluctuations which can result in periodic surge events

CENTRIFUGAL COMPRESSOR MAP AND SURGE





Brun et al. 2010

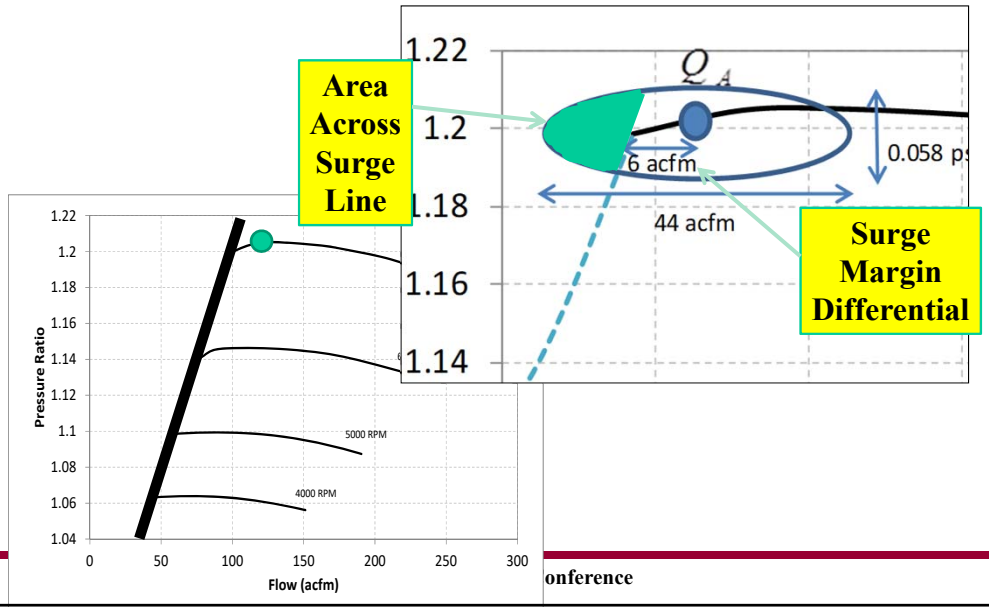
Flow pulsations can cause periodic surge in centrifugal compressor

PROBLEM

- The performance of a centrifugal compressor is defined by its operating map.
- This map is critical in assessing the operating range of a compressor for both steady- state and slow transient system scenarios.
- The compressor map does not provide a complete picture of how the compressor will respond to rapid transients (pulsations) or the affect on its surge margin.
- The response of the compressor to rapid transient events is unique to each system since it is a function of the acoustic and impedance characteristics of the associated piping system.

Unexpected periodic surge has been observed in compressors when pulsations were present.

OPERATING MAP ELLIPSE



SOLUTION

- Extend API 618 Pulsation Analysis to centrifugal compressor flanges
- Predict unsteady compressor operating map area taking into account piping impedance
- Determine net effective surge margin reduction
- Use GMRC guideline criteria to determine safe operating ranges,
  - Add margin to surge control line
  - Install additional pulsation control between the two compressor types
    - Orifice plates
    - SBA
    - Filter Bottles

HIGH FREQUENCY PULSATION SOURCES IN TURBOMACHINERY

- fpb = RPM * b / 60; impeller blade pass frequency
- fp = RPM * nb /60 or RPM * nd /60; harmonics
- Variables
  - RPM – impeller rotating speed in revs/min
  - b = Number of Impeller Blades
  - d = Number of Vanes (Diffuser)
  - n = Integer 1, 2, 3, …
- More complex interactions may also be significant
- Normally present at a low amplitude
- When present at several psi or more, they can be problematic

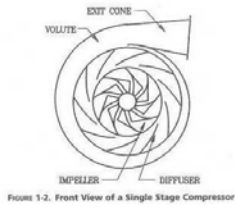
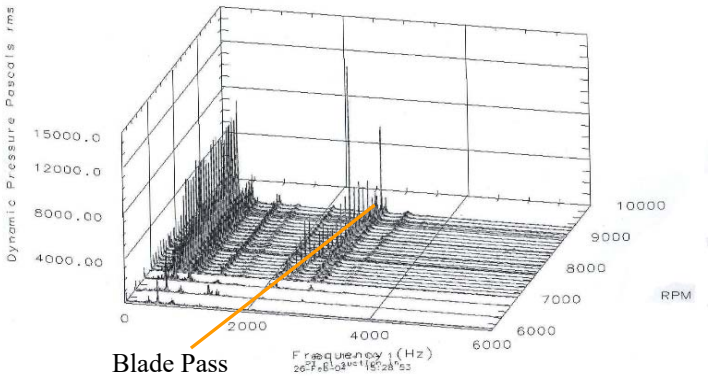


FIGURE 1-2. Front View of a Single Stage Compressor

BLADE PASS SIGNATURE IN PULSATIONS

Waterfall plot shows pressure pulsations in compressor discharge piping during speed change.



Blade Pass Frequency

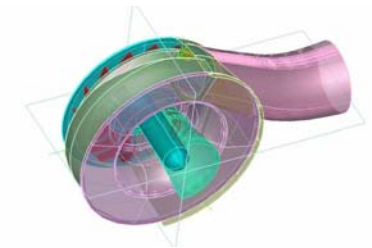
EXAMPLE: EXCITATION FREQUENCIES

Consider a compressor having an impeller with 17 blades and rotating at 9600 RPM.

Rotation Frequency: f_shaft = 9600 RPM/60 = 160Hz

Blade Pass Frequency: 160Hz * 17 blades = 2720 Hz

Rotating Stall: Approx. 1/10 to 1/3 of 160Hz ~ 15 – 50 Hz



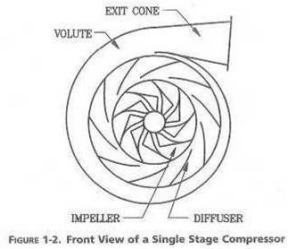


FIGURE 1-2. Front View of a Single Stage Compressor

Volute cutwater or "tongue" can be source of pressure pulsation at blade pass frequency

DUCT AND SHELL MODE INTERACTION

- A duct mode may excite a shell mode if the frequencies are similar and the mode shapes match



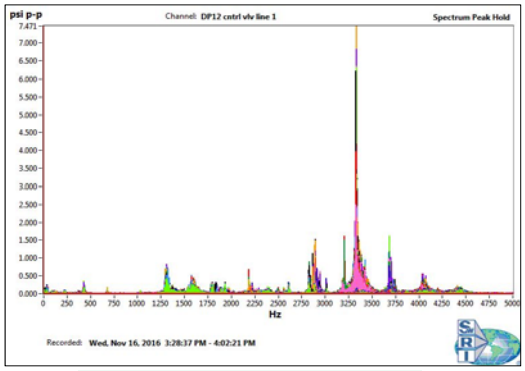
- Lightly damped resonance can lead to high stress concentrations at branch connections or other fittings, which can lead to fatigue failures

Valve Related Noise and Vibrations

- Noise
  - Discrete tonal noise from vortex-shedding excitations
  - Broadband noise from turbulence in high energy flow or pressure reduction (AIV)
  - Can have both
- Chatter or Vibrations
  - Acoustic excitation of risers or piping associated with a closed valve creating pulsations and chatter of PSV or check valve (FIV)
  - Discrete acoustic excitation of valve internals excites radial and shell modes of the main piping resulting in vibrations and/or failures (FIV)
  - High amplitude broadband excitation from high mass flows creating vibrations through a pressure reduction and transfer of flow energy (AIV)

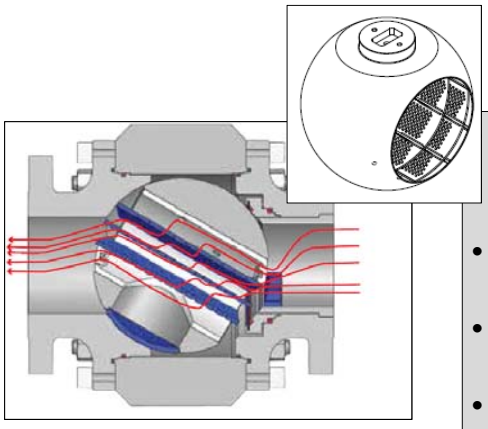
Valve Pulsations: Control Valve Example

- Loud tonal noise created by 3300 Hz pulsation coupling with shell mode of connecting piping
- Approx. 106 dBA
- Below ring frequency (4,000 Hz) of pipe—low transmission losses
- Higher pulsation amplitudes at 4,400 Hz, but not associated with loud external noise since above ring frequency
- Occurred at a metering station near noise sensitive areas (NSAs)



Noise only occurred when valves in partially closed position

Flow Control Valve
Noise Reducing Trim



Examples of a Noise Reducing Trim—Valves in Various Open Positions
Images Courtesy of GE Becker and Flowserve

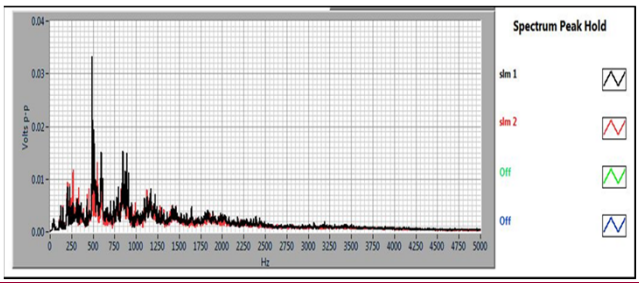
Valve Internal Noise Control Trim Creates Flow Across Cavities

- Can Result in V-S When in Various % Open Positions
- Excites Acoustic and Mechanical Piping Modes
- Noise, Pulsations, and Vibration Problems

Control Valve Solution

- Replaced valve with different noise trim
- High frequency noise peaks virtually eliminated
- All NSAs had an Ldn less than 55 dBA

Location	L_{eq} dBA	L_{dn} dBA
NSA #1	47	53.4
NSA #2	42	48.4
NSA #3	47.5	53.9



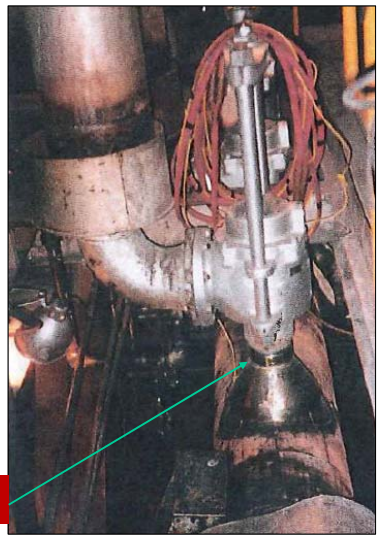
PRESSURE SAFETY (RELIEF) VALVES

Problem:

- Vortex-shedding of flow past PSV risers can excite the acoustic and mechanical modes of the piping
- This can cause the valve to lift, chatter or be unable to re-seat after lifting due to high pulsations/vibrations

Solutions:

- New spring stiffness
- Increase piston mass or dome volume
- Add drag rings
- Alter riser geometry
- Orifice
- Side branch absorber



ACOUSTICALLY-INDUCED VIBRATION (AIV)

- Acoustically-Induced Vibration (AIV) refers to high-frequency broadband excitation and high-frequency vibration (typically 100-2000 Hz) in piping downstream of a pressure-reducing device (e.g., a control valve or pressure relief valve)
- Can result in high-cycle fatigue failures at branch connections or welded supports
- First identified in 1983 by Carucci and Mueller
- Often a concern in flare/blowdown piping with thin walls and large diameters



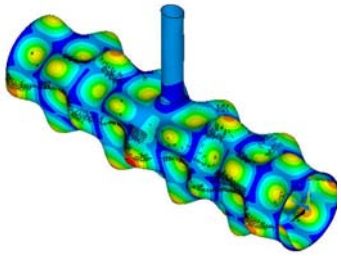
Image Courtesy Tyco Valves & Controls



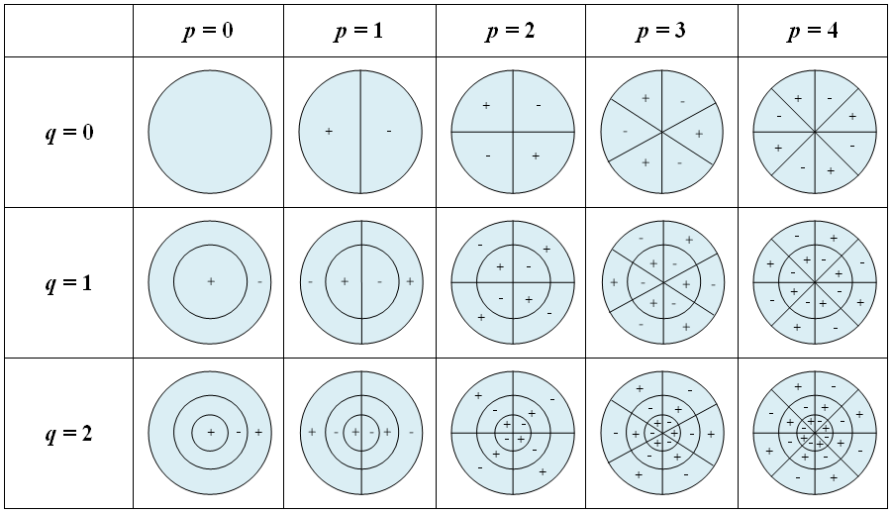
Image Courtesy Chemical & Process Technology

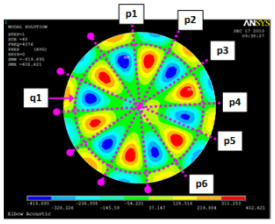
THEORY OVERVIEW

- AIV-related fatigue failures are caused by the following four physical phenomena:
  1. Excitation from a pressure-reducing valve causes high-frequency pressure fluctuations in downstream piping.
  2. These fluctuations excite higher order acoustic modes in the pipe with circumferentially varying pressure mode shapes.
  3. The acoustic pulsations couple to shell modes of the main piping.
  4. Branch connections or other welded discontinuities in the main line serve as stress risers.

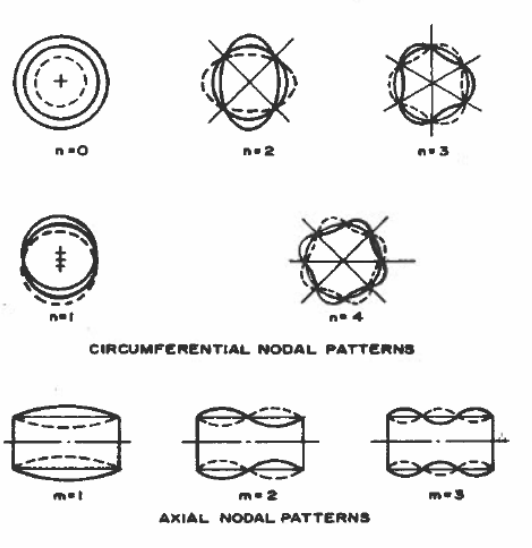


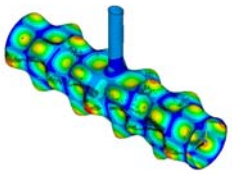
THEORY: ACOUSTIC CROSS MODES

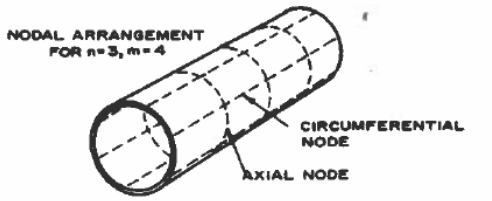




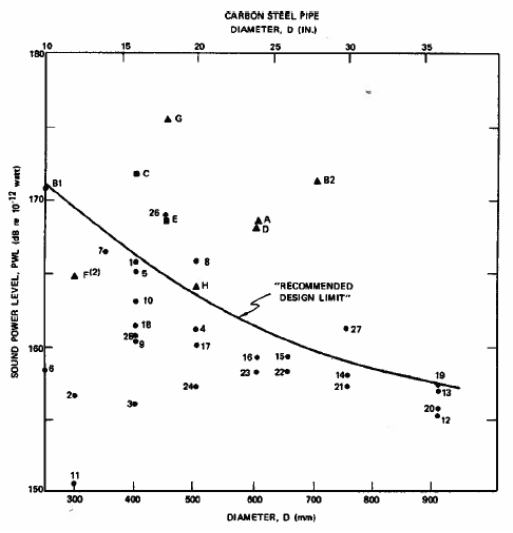
THEORY: PIPE SHELL MODES



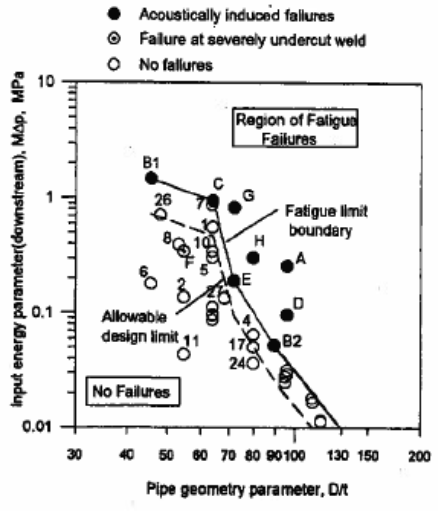




EXISTING AIV SCREENING METHODS

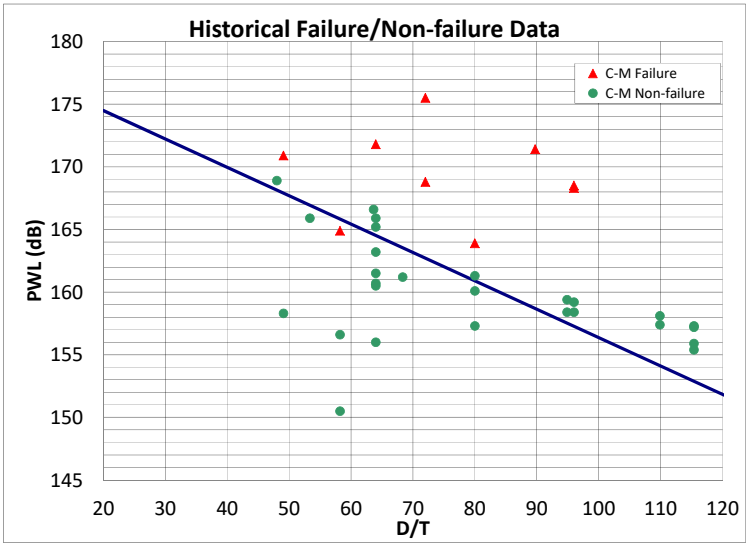


Carucci-Mueller Design Curve



Eisinger Design Curve

EXISTING AIV SCREENING METHODS



Evans, Allison, and Arnett 2012

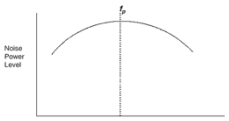
EXISTING AIV SCREENING METHODS

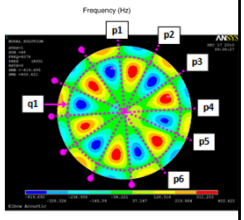
The Energy Institute introduced a screening methodology* for AIV:

- Simple source PWL computation
- PWL decay to branch connection and addition of PWL from multiple sources at each branch
- Estimate of fatigue life from curve-fit data (data from FE models calibrated to historical failure/non-failure data)
- Fatigue life estimation including reduction due to weldolet fittings and small branch diameter to main line diameter ratios
- Likelihood of Failure (LOF) computed from estimated fatigue life

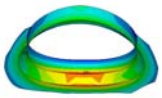
*See "Guidelines for the avoidance of vibration induced fatigue failure in process pipework," Energy Institute, 2nd Ed., Jan. 2008

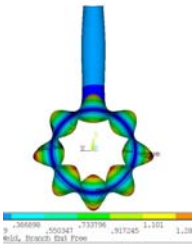
DETAILED ANALYSIS METHODS





- Valve excitation analysis, acoustic analysis and finite element analysis can be performed to determine coincidence of acoustic and pipe shell modes
- Forced response analysis of FE model at coincident modes can be performed with shell models to determine stresses at fillet weld and resulting fatigue life
  - Excitation from valve amplified by acoustic amplification factor to account for acoustic resonance
  - Stresses evaluated using mesh-insensitive procedure for welded joints in accordance with Section 5.5.5 of the ASME Boiler and Pressure Vessel Code, Section VIII, Division 2
- Can evaluate relative changes better than absolute life





ANALYSIS METHOD COMPARISON

	Carucci-Mueller	Eisinger	Modified C-M	Energy Institute	Finite Element
Calculates PWL	X		X	X	X
Includes pipe diameter	X	X	X	X	X
Uses historical data	X	X	X	X	See (1)
Includes pipe wall thickness		X	X	X	X
Includes multiple sources & decay				X	X
Includes connection type				X	X
Includes branch diameter				X	X
Includes acoustic/structural coincidence					X
Includes excitation frequency					X
Allows detailed analysis of design alternatives					X
Fatigue life calculation					X
Expensive?					X

[1]FEA methods must be calibrated with test and historical data

AIV SOLUTIONS

- AIV stresses can be reduced by many design changes or retrofits
  - Changes to valve (low noise trim, multiple valves)
  - Piping changes (increase spacing from noise source, increase wall thickness, change branch connection type or size)
  - Support type changes
  - Reinforcement
  - Weld quality
  - Stiffener rings
  - Damping
  - Other (tuned vibration absorbers, acoustic mode interference) – these are concepts only…

TESTING OF AIV SOLUTIONS AT SWRI

- Tested multiple header geometries and AIV solutions through series of 170 dB Nitrogen blowdown tests:

Test	Configuration	% reduction
1a	36" baseline	-
1b	36" clamps	51.8%
1c	36" damping wrap	11.1%
1d	36" tube bundles	30.1%
2a	20" baseline	-
2b	20" clamps	17.8%
2c	20" damping wrap	17.0%
2d	20" tube bundles	28.2%
3a	12" baseline	-
3b	12" clamps	15.8%
3c	12" damping wrap	8.4%
3d	12" tube bundles	*

AIV SUMMARY

- Acoustic-induced vibration has historically led to many piping failures in piping downstream of pressure-reducing devices
- Multiple screening tools were presented to evaluate the susceptibility of a piping system to acoustic fatigue failures
- Many design options available to reduce the likelihood of an acoustic fatigue failure
- AIV is easiest to catch & prevent at design stage
- Fatigue life analysis for existing systems can be expensive and validated methods are still not available
- Be cautious when selecting thin-wall pipe downstream of noise sources, even if pressures are low!

Mechanical Design

Mechanical Design of Reciprocating Compressors and Piping Systems

- Purpose of Mechanical Design
  - Reduce Vibration Risk – Increase Reliability.
  - Predict Mechanical Characteristics.
  - Mechanical design parameters include support types and locations, structures, pipe routing, vessel design, etc.

Mechanical Analysis of Compressors and Piping

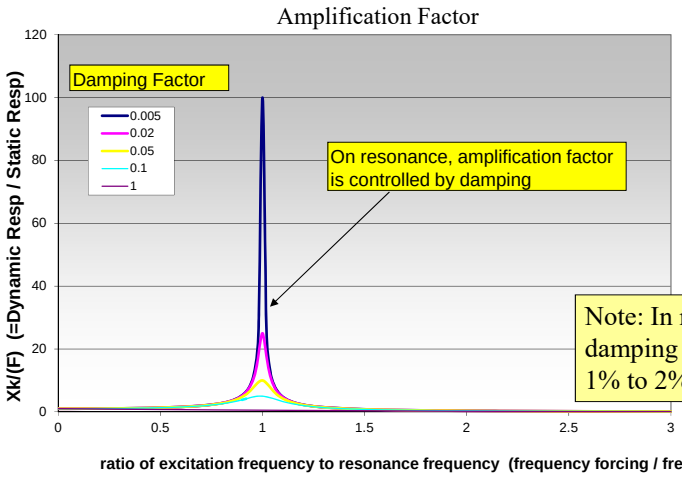
- Two Categories
  - Piping Spans (Simpler Systems)
  - Compressor Manifolds (More Complex Systems)
- API 618 Design Approaches
  - Design Approach 1 – Analytical Acoustical Design
  - Design Approach 2 – Full Acoustical Analysis + Mechanical Piping Review
  - Design Approach 3 – Design Approach 2 + Mechanical Manifold Analysis

Vibrations of Complex Systems

- Complex Systems Have Many Resonant Frequencies.
- For Every Resonant Frequency, a Corresponding Mode Shape (Deflection Pattern) Exists.
- Vibration Amplitudes Are Function of the Force Amplitude, the Frequency Ratio And Damping.
- A System at Resonance Will Have Much Higher Vibration.

Response of a Single Mass System

Forced Response of Mass-Spring System
F(t)=F sin (2 π *freq*t)….harmonic....sinusoidal



Key Points

In order to reduce response on resonance, we have several options
1 - add damping (hard)
2 - add mass (lower natural frequency)
3 - add stiffness (increase natural frequency)

Note: In many piping systems, damping will range from 1% to 2% (Q = 25 to 50).

A Simple Beam (or Run of Pipe)

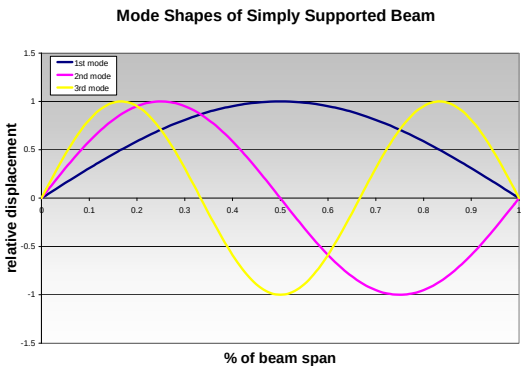
$$\text{Freq_Response} = \frac{1}{2 \cdot \pi}\sqrt{k/m}$$

$$\text{Freq_Response} = \frac{\pi \cdot \text{n}^2}{2 \cdot l^2}\sqrt{EI/m}$$

$n = (1,2,3...)$

Note: m= weight (lb_f) per unit length / g

For every resonant frequency, there is a distinct mode shape. The mode shape describes the relative vibration amplitude at that frequency





Simply supported beam
(pinned at both ends)

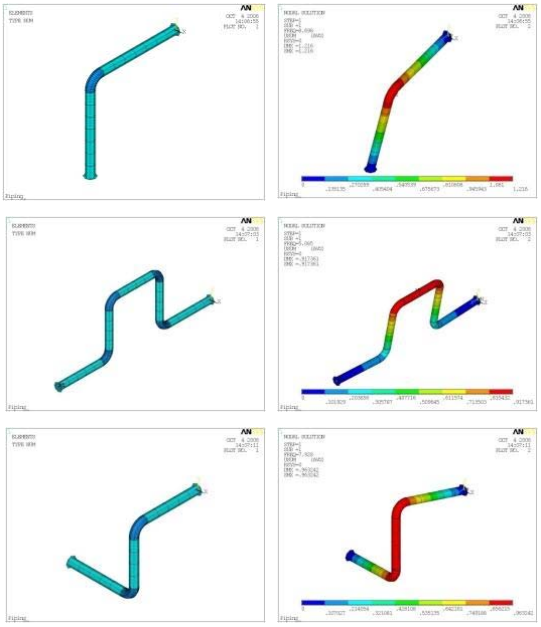
Piping Design for Vibration Control

Main Factors in Piping Design for Vibration Control

- Restraint Locations
- Restraint Types
- Excitation Source (Pulsation Amplitudes & Frequencies)
- Maximize Mechanical Natural Frequencies (Place Above Excitation Frequencies)
- API 618 Minimum MNF = 2.4 * Running Speed/60

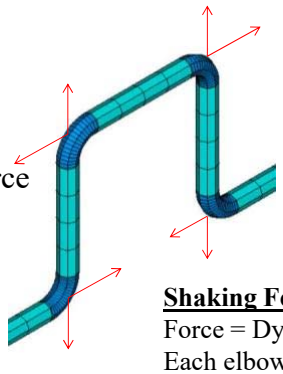
Typical Piping Configurations

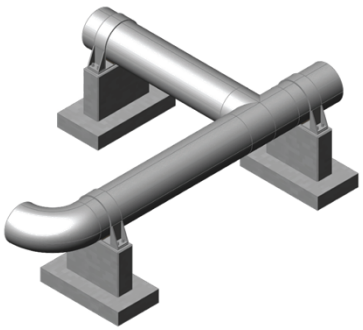
- 1st column shows various simple piping layouts.
- 2nd column shows the deflection pattern of lowest mechanical natural frequency.
- Which points have the greatest deflections?



Clamp Locations

- Near Elbows and Tees (Coupling & Flexibility)
- Near Concentrated Masses (Valves)
- On Long Spans (See Following Chart)





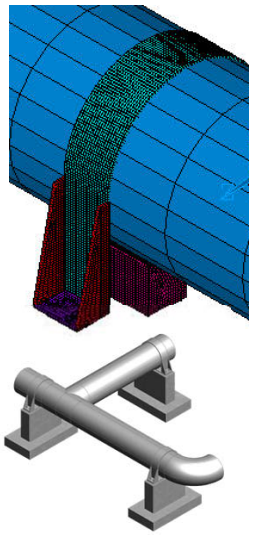
Shaking Forces from Pulsation

Force = Dynamic Pressure * Pipe Cross-Sectional Area

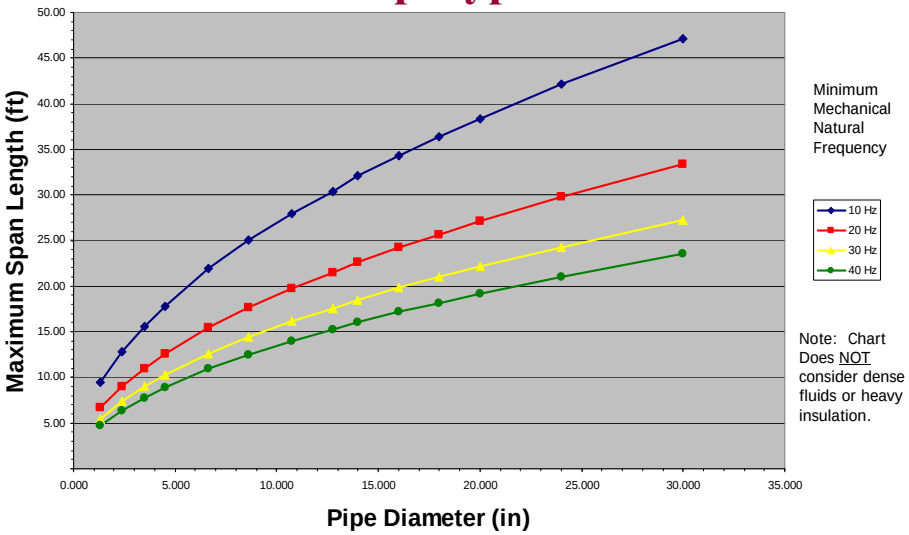
Each elbow has unique pulsation amplitude & phase

Clamp Locations - Continued

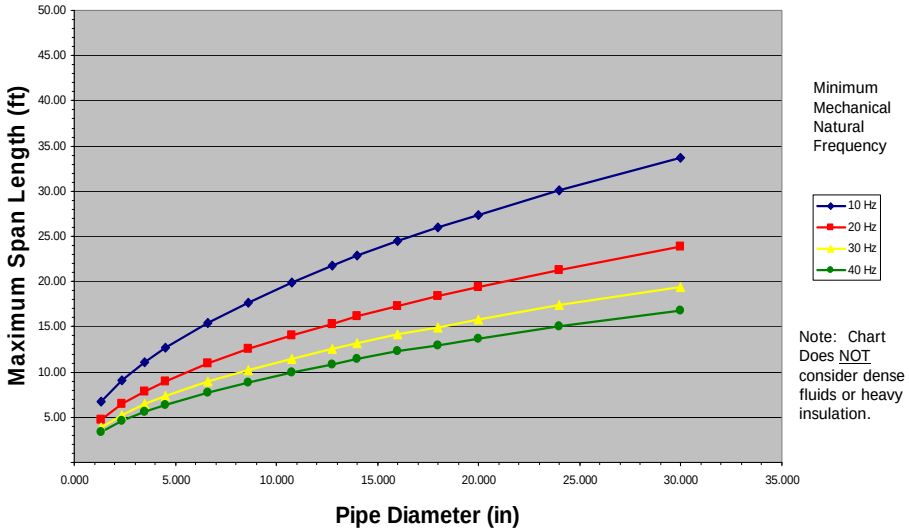
- Design Frequencies
  - Mechanical Responses Above Excitation
  - 2X + 20% for Reciprocating Units
  - Higher Speed Compressors Need Shorter Spans Between Clamps
  - 10 to 15 Hz for Centrifugal Units
- Where are Clamps No Longer Necessary?
  - Depends on Acoustic Analysis (Large Vessels)
- Consider Thermal Expansion



Maximum Straight Span Lengths Between Effective Strap Type Restraints



Maximum Span Lengths Between Effective Strap Type Restraints For Spans with Elbows



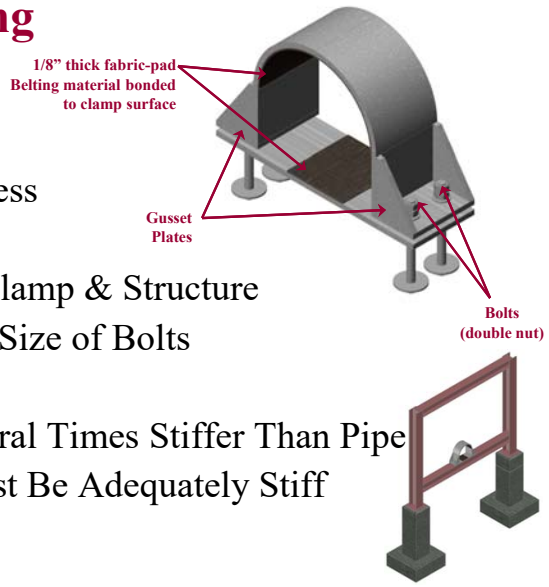
Restraint Types and Stiffness

- Different Restraints Have Different Stiffness Properties

- Simple Weight Supports
- Guides, Stops, Spring Cans and Hangers
- Box Clamps
- U-bolts
- Strap Type Hold-down Clamps (With Or Without Wedges) Are Best For Vibration Control.

- For Accurate Modeling Predictions, It Is Essential to Accurately Estimate Stiffness in All Directions

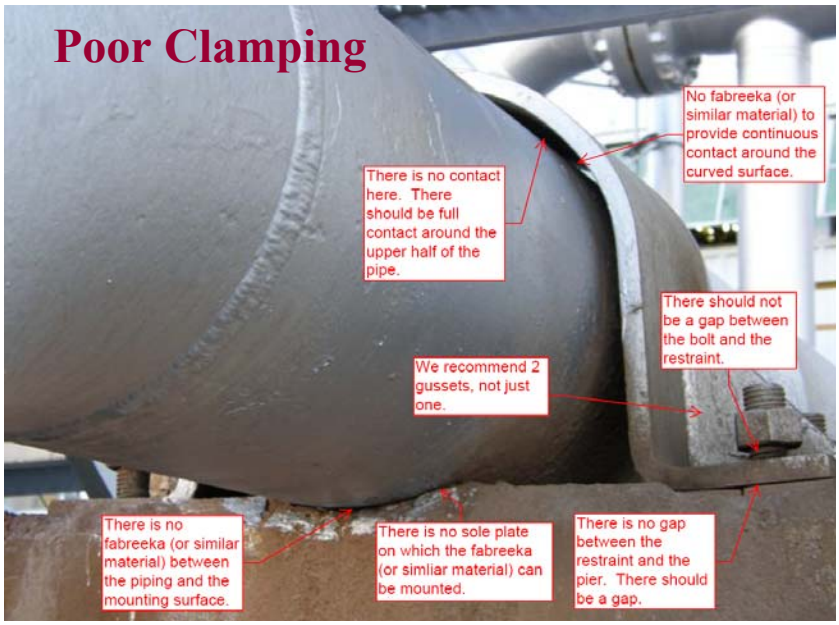
Effective Clamping



Clamp Characteristics

- Adequate Plate Thickness
- Side Gussets
- ½ Inch Gap Between Clamp & Structure
- Adequate Number and Size of Bolts
- Clamp Liner Material
- Clamp Should Be Several Times Stiffer Than Pipe
- Attached Structure Must Be Adequately Stiff

Poor Clamping





Flexible Structure Under Clamp





Excessive Gap

Stretch Tube Design (good and bad).



Poor Clamping

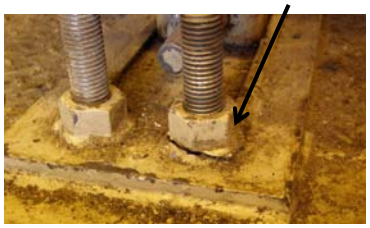


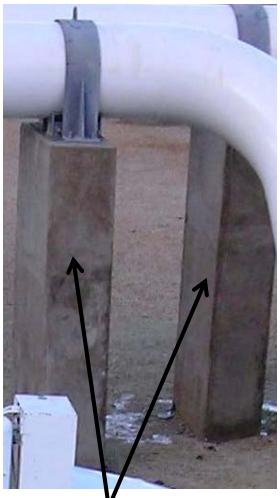
Wedge is Too Tall & No Liner

Poor Clamping



Nuts Welded to Plate - Failed

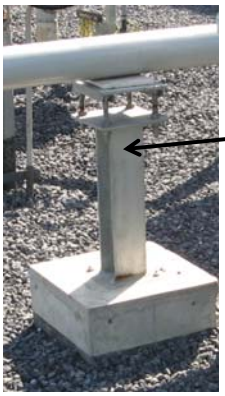




Good Clamp – but Piping is Elevated and Pier is Too Tall

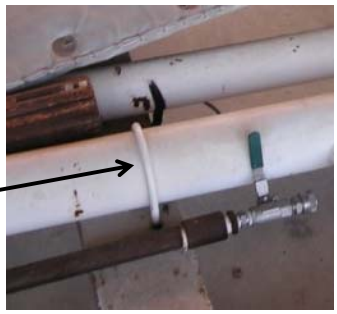
Flexible Dummy Leg

Poor Clamping



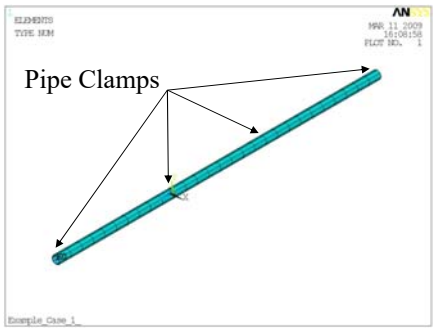
- Slender column
- Weak link at bolts
- No clamp – can lift off

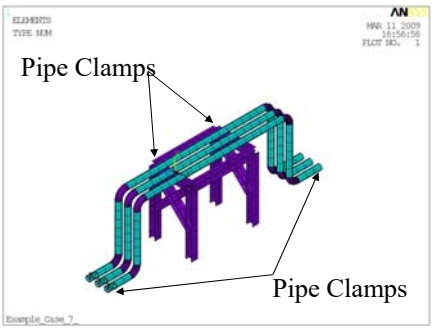
- Simple U-Bolt
- Pipe can easily rotate
- Fretting & wear concern



Elevated Piping

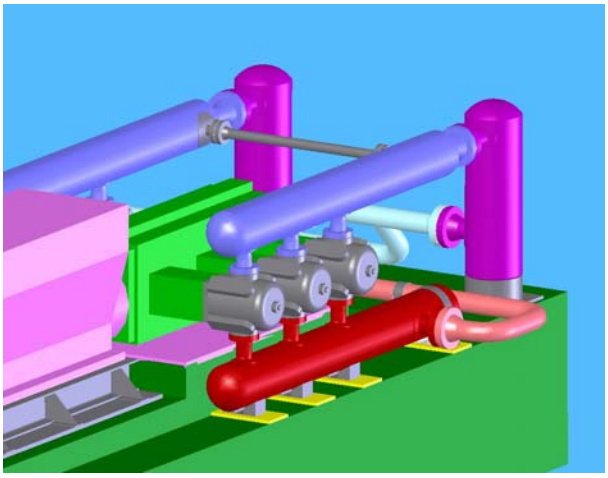
- Elevated Piping Will Almost Always Have Higher Vibration
- This Is Due to More Flexible Supports and Piping (More Elbows).
- It Is Easier to Control Vibration on Grade Level Piping.
- If Piping Must Be Elevated, Use Good Pulsation Control, Stiff Support Structures, and Tie Multiple Components Together.





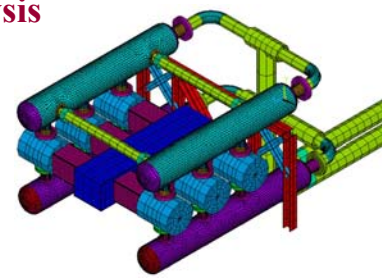
Compressor Manifold Systems

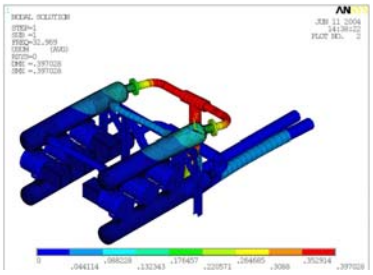
- What: The Cylinders, Bottles, Frame Components, and Attached Piping.
- Why: Lots of Energy and Vibration Potential Near the Compressor Unit.



Modal Analysis

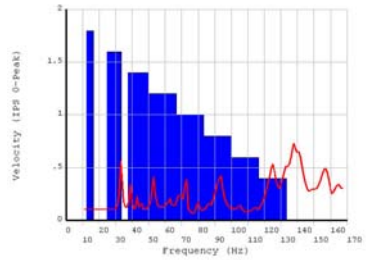
- Predict Mechanical Natural Frequencies of Manifold System.
- Vibration Amplitudes Will Be Significantly Amplified If the System Is Excited at a Natural Frequency.
- Modify the System to Place the Mechanical Responses Where They Are Less Likely to Be Excited.

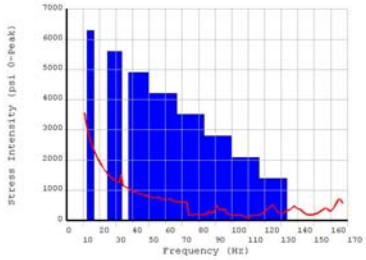




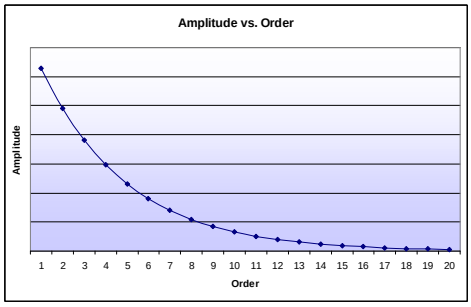
Forced Response Calculations

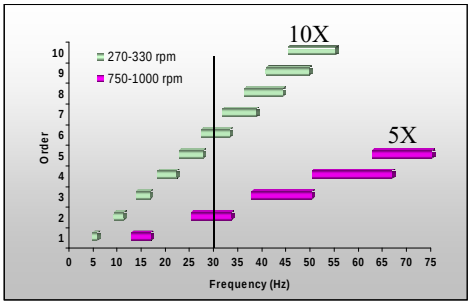
- Resonance Avoidance is Best
- Not Always Possible with
  - Higher Operating Speeds
  - Wider Speed Ranges
- Forced Response Calculations
  - Verify Acceptable Vibration
  - Verify Acceptable Dynamic Stress





Low Speed vs. High Speed



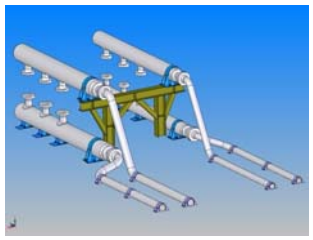


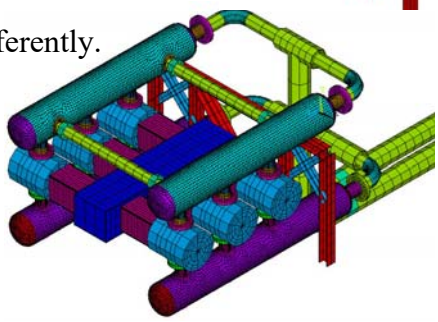
- 120 - 300 RPM (acoustic predominates)
- 300 - 600 RPM (acoustic, cylinder stretch)
- 600 - 900 RPM (acoustic, cylinder stretch, unbalance)
- 900 - 1200 RPM (cylinder stretch, unbalance, shell mechanics)
- > 1200 RPM (cylinder stretch, unbalance, radial acoustics, shell mechanics)

Mechanical Analysis – Typical Modifications

- Pipe Clamp Locations and Types.
- Suction Bottle Support Frame.
- Discharge Bottle Restraints.
- Nozzle and Repad Specifications.
- Suction Bottle Bracing.
- Each System Will Respond Differently.







Inspection Ports And Auxiliary Attachments



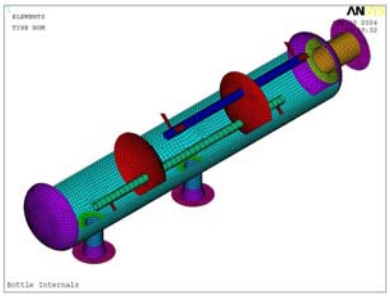
Bottles often have small bore auxiliary attachments for inspection, instrumentation, etc.

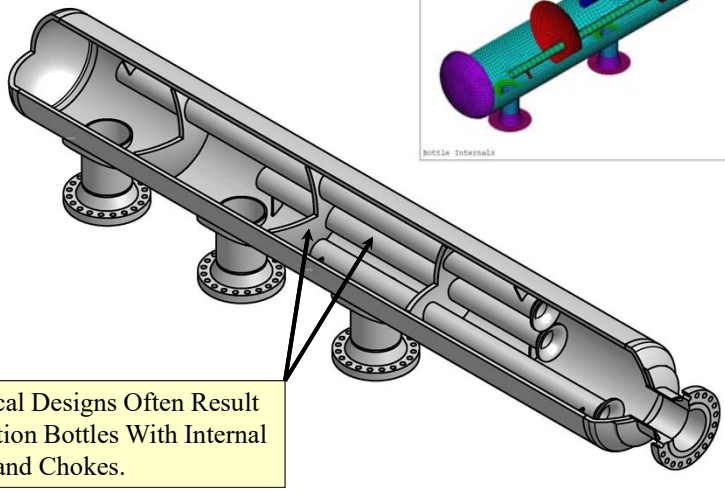
Localized high frequency vibration on ports can result in failures.

Minimize ports in size and quantity as much as possible, especially on high speed reciprocating equipment.

Design Considerations for Internal Baffles & Chokes

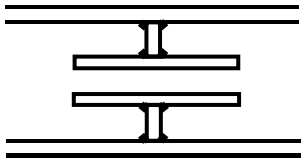
- Predict Dynamic Pressure Loads During Pulsation Analysis
- Apply loads to finite element model to predicted stresses





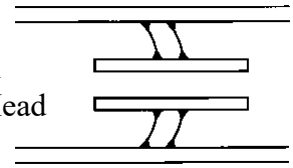
Acoustical Designs Often Result in Pulsation Bottles With Internal Baffles and Chokes.

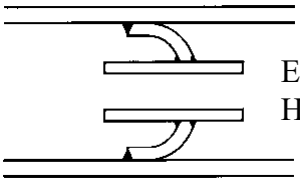
Baffle Types



Flat Plate (Not Recommended)

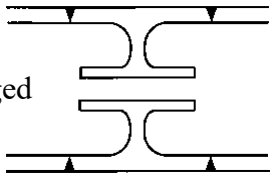
Spherical Dished Head





Ellipsoidal Head

Forged

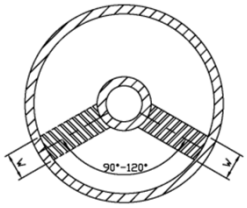


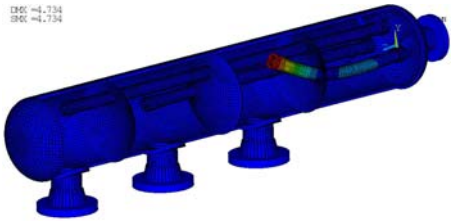
If Baffles stresses are too high:

- Redesign the acoustics / Modify operating conditions.
- Use a thicker baffle (same as bottle shell, up to 1").
- Increase the choke wall thickness.
- Use a different type of baffle.
- Reinforce the choke or vessel wall (wrap)

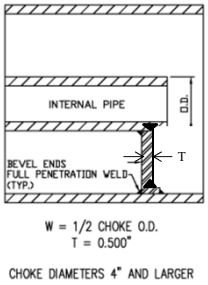
Unsupported Internal Chokes Can Fail

- Unsupported or Under-Supported Chokes Can Vibrate and Fail if their Mechanical Response Coincides with an Excitation Source.
- No more than 2 Pipe Diameter Overhang.



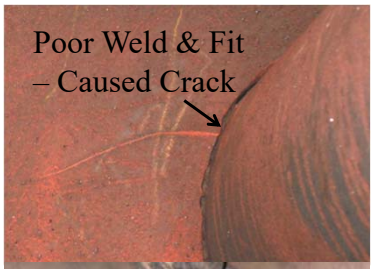






Baffle And Choke Welding / Fabrication

- Many Vessel Internal Failures Due to Poor Welding
- Baffle to Bottle Weld - Full Penetration
- Baffle to Choke Weld
  - Full Penetration on One Side OR
  - Fillet Welds on Both Sides
- All Welds 360° Around
- As Smooth as Possible



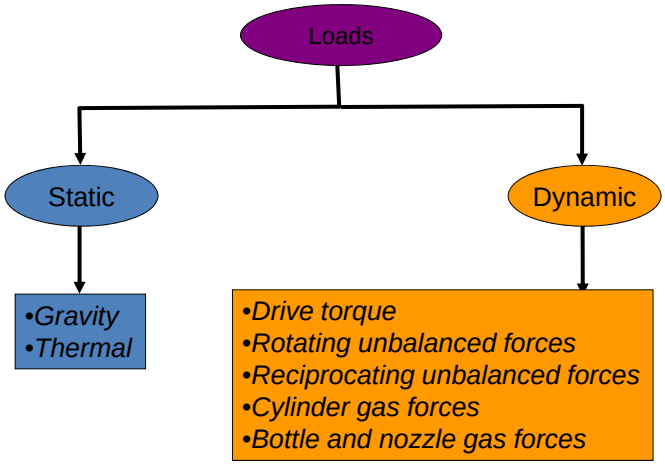


SKID AND FOUNDATION DESIGN

SKID AND FOUNDATION LOADS

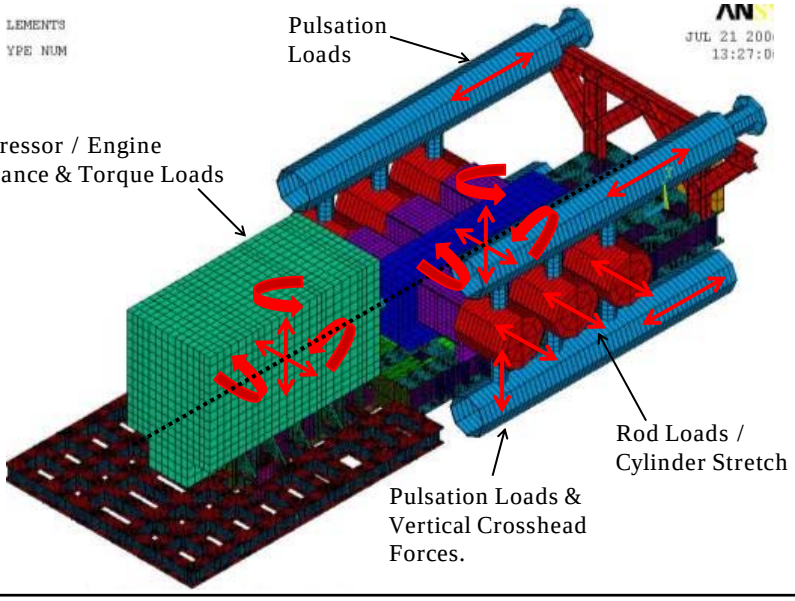
Functions of Skid and Foundation

- Provides Rigidity for the Engine and Compressor
- Sets Position of Machines and Accessories
- Maintains Alignment
- Absorbs and Reacts to Excitation Forces
- Transmits Net Forces to the Foundation / Soil



The machine foundation must provide support of the installed machinery, and react all forces and moments necessary to provide restraint and maintain machine alignment.

PRIMARY DYNAMIC EXCITATION FORCE DIRECTIONS



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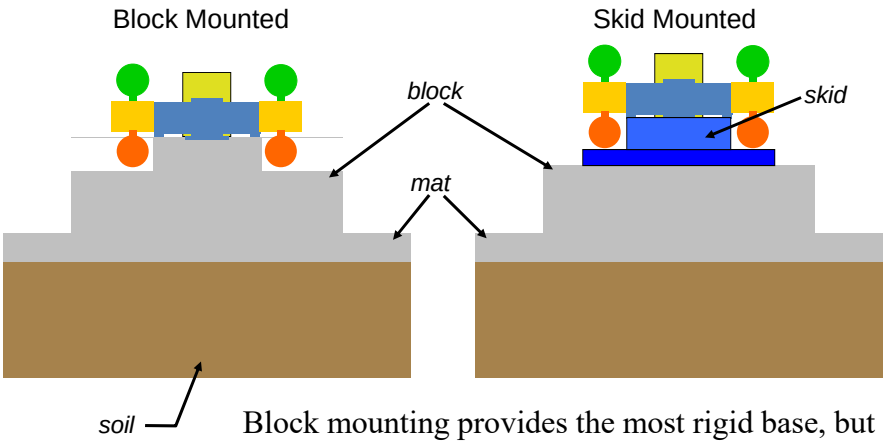
COMPRESSOR LOADS

Reciprocating Machinery
- Inherently Unbalanced
- Forcing Frequencies Near Foundation Resonances
- Foundations Designed to React Shaking Loads
- Transmit Vibration to the Ground

Rotating Machinery
(Turbines, Blowers, Centrifugal Compressors, etc.)
- Relatively Small Dynamic Loads
- Running Speed Above Foundation Resonances
- Foundations Designed to Resist Static Loads

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FOUNDATION / MOUNTING ALTERNATIVES BLOCK MOUNTED VS. SKID MOUNTED

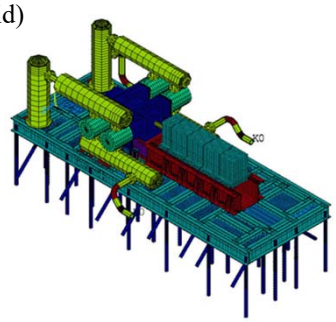


Block mounting provides the most rigid base, but most modern reciprocating compressors are skid mounted due to cost and packaging issues.

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FOUNDATION / MOUNTING ALTERNATIVES

- Compressor skid on block foundation
  - Typically high speed compressors
  - Typically 4-8 feet deep foundation (depends on soil)
- Compressor mounted directly to a block foundation
  - Typically slower speed, higher hp (5000+ hp)
- Concrete block on piles (with or without a skid)
  - Driven piles or screw piles
- Skid on steel pilings (no concrete)
  - Requires a stiffer skid design
  - Typically less damping
- Gravel Pad (less than 1000 hp)



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SCREW PILES FOR SKID SUPPORT

- Screw piles have recently been used to support a variety of reciprocating compressor skid packages.
- One key advantage of screw piles is their faster installation process. However, they must also be able to adequately support the compressor package and all of its inherent dynamic loads to prevent excessive vibration.

Screw pile mounted skid during installation (fill will be added later).



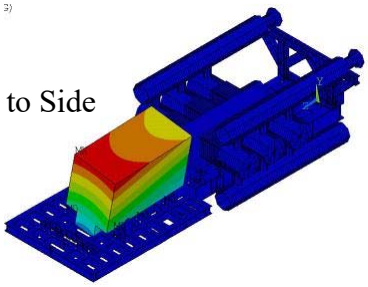
161

COMMON ENGINE MODES

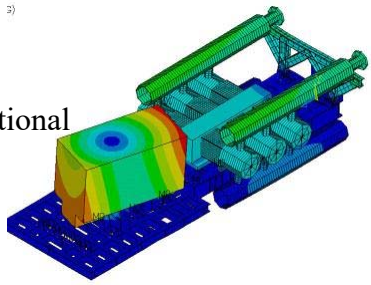
Controlled by engine mass and skid structure underneath.

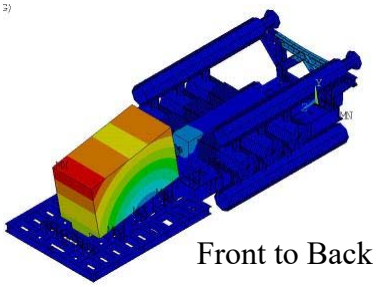
Should be above rpm range.

Side to Side



Rotational





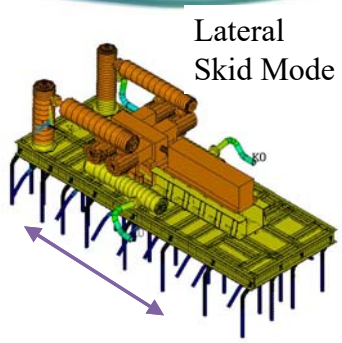
Front to Back

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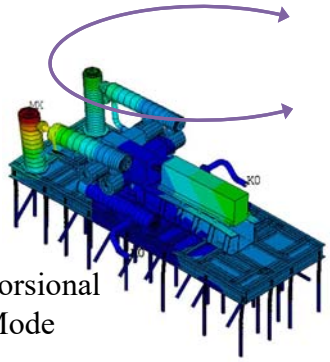
COMMON SKID MODES

Controlled by skid mass and foundation stiffness.

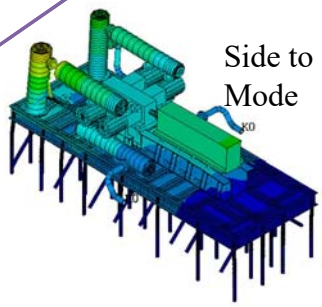
Can be above or below rpm range.



Lateral Skid Mode



Torsional Mode



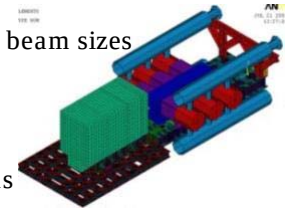
Side to Side Mode

DESIGN OBJECTIVE

- Primary concern is excessive vibration
- All compressor skids (whether on a concrete foundation or not) have several low frequency mechanical natural resonances
  - Based on mass and stiffness of system
  - Coincidence with frequencies of excitation can cause excessive vibrations.
- Want to avoid coincidence, especially on or near 1X or 2X orders of the compressor running speed



GENERAL GUIDELINES FOR SKID DESIGN FOR VIBRATION CONTROL



- Keep skid as low and stiff as possible with adequate beam sizes
- Mount discharge bottles off-skid (to keep low)
  - 6-8” from top of concrete to bottom of bottle
- Perform static and dynamic analyses on new designs
- Gusset beams at critical points (bolt and mounting locations, etc.)
- Keep anchor bolts near beam webbing
- Outriggers should be bolted and grouted in place
- Add concrete with rebar under the compressor, engine & scrubbers
- Use sufficiently long anchor bolts internally and externally
- Have direct load transfer paths under key locations

Thank You - Questions?

- Eugene “Buddy” Broerman
  - eugene.broerman@swri.org
  - (210) 522-2555
- Sarah Simons
  - sarah.simons@swri.org
  - (210) 522-2418
- Ben White
  - benjamin.white@swri.org
  - (210) 522-2554



Poll #3 – Future Topics of Interest?



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(General Partner)

ENTERPRISE PRODUCTS OPERATING LLC

January 7, 2025

via email: nm.regionalhaze@env.nm.gov
mark.jones@env.nm.gov

Mr. Mark Jones
New Mexico Environment Department
Air Quality Bureau
525 Camino de Los Marquez – Suite 1
Santa Fe, New Mexico 87505

Re: Comments of Enterprise Field Services, LLC on NMED's Revised Draft Regional Haze State Implementation Plan Revision

Dear Mr. Jones:

These are the comments of Enterprise Field Services, LLC ("Enterprise") on the New Mexico Environment Department's ("NMED" or the "Department") revised draft State of New Mexico Regional Haze State Implementation Plan Revision Second Planning Period (2019-2028) and 20.2.68 NMAC – Regional Haze Requirements ("Revised Draft SIP").

Section 169A of the Clean Air Act ("CAA") requires states to develop state implementation plans ("SIPs") containing "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal" of eliminating visibility impairment in protected Class I federal areas that results from manmade air pollution. 42 U.S.C. § 7491(b)(2). The U.S. Environmental Protection Agency's ("EPA") regional haze rule requires that states meet the CAA's requirement for "reasonable progress" toward the national visibility goal over successive ten-year planning periods. 40 C.F.R. § 51.308(f). NMED's Revised Draft SIP responds to the regional haze program's requirement for SIPs to address regional haze for the program's second planning period, running from 2018 to 2028.

On August 26, 2024, NMED released an initial draft of the state's regional haze SIP, ("August 2024 Draft SIP"). Enterprise is the owner and operator of the following three facilities (collectively, the "Enterprise facilities") that have been subject to these proceedings:

- Blanco C & D Compressor Station ("Blanco") located in San Juan County, New Mexico – approximately 39 miles from the nearest Class I Area
- Chaco Gas Plant located in San Juan County, New Mexico ("Chaco") – approximately 49 miles from the nearest Class I Area

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- South Carlsbad Compressor Station ("South Carlsbad") located in Eddy County, New Mexico – approximately 26 miles from the nearest Class I Area

Enterprise submitted comments to NMED addressing the August 2024 Draft SIP on September 20, 2024 ("September 2024 Enterprise Comments"). Those comments are included as Attachment A to this submittal. While Enterprise appreciates NMED's efforts to revise the SIP to address one issue—the nitrogen oxides ("NOx") removal efficiency of selective catalytic reduction ("SCR") controls—addressed in the September 2024 Enterprise Comments, Enterprise asks that NMED consider further revisions to the SIP to address *all* of Enterprise's previously submitted comments. Enterprise also submits these additional comments on the Revised Draft SIP for NMED's consideration.

As noted above, Enterprise appreciates the Department's efforts in the Revised Draft SIP to address issues related to the NOx removal efficiency of SCR controls. But as described in greater detail below, the impact of this revision on the control requirements contained in the Revised Draft SIP demonstrates the need to address the other issues raised in Enterprise's previous comments. Even in the absence of substantial further revisions, however, the Revised Draft SIP's new control requirements and emission rate limits highlight the need to provide additional compliance flexibility, should the control requirements and limits in the Revised Draft SIP be retained. To that end, and without conceding that an SCR-based emission rate is appropriate, Enterprise renews its request for facility-wide emission rate limits. Based on the limits in the Revised Draft SIP, Enterprise specifically requests an emission rate limit of 50.58 lbs/hr for the Blanco units and a facility-wide weighted average rate of 15 ppmvd @ 15% oxygen for the units at South Carlsbad. The reasons for these requests are provided in more detail below.

I. The Revised Draft SIP

As NMED notes in the Revised Draft SIP, the Department has made minor corrections to the August 2024 Draft SIP and, most significantly, has revised its cost estimates and cost-effectiveness values to: (1) adopt a different method for adjusting for inflation; and (2) assume a more realistic NOx removal efficiency for sources that provided information justifying such removal efficiencies. Revised Draft SIP at 191. This has resulted, in some instances, in changes to the units subject to new control requirements, the emission control technology such control requirements are based on, and/or the emission rate limits contained in the Revised Draft SIP (and the accompanying draft regulations).

As a result of NMED changes to its cost assessment, NMED has proposed revised control determinations and emission rate limits for the Enterprise facilities.

For Blanco, NMED's August 2024 Draft SIP would have required emission rate limits based on installation and operation of SCR controls, and emission rate limits of 6.52 lb/hr for unit T-C01; 6.66 lb/hr for unit T-C02; and 12.11 lb/hr for unit T-D01. *See* Revised Draft SIP, App. G at 2. The Revised Draft SIP retains the determination that SCR is justified for these units but adjusts

the emission rate limits to 13.04 lb/hr for unit T-C01; 13.32 lb/hr for unit T-C02; and 24.22 lb/hr for unit T-D01. *Id*.

For Chaco, the August 2024 Draft SIP would have required emission rate limits based on SCR, and emission rate limits of 2.62 lb/hr for unit 35; 3.02 lb/hr for unit 36; and 2.97 lb/hr for unit 37. *See id*. The Revised Draft SIP eliminates these requirements. *Id*. NMED also proposed in the August 2024 Draft SIP to require an emission rate limit of 0.5 g/bhp-hr for Chaco unit 14 based on installation and operation of a low emission combustion system ("LEC"). *See id*. The Revised Draft SIP does not alter this proposed requirement. *Id*.

For South Carlsbad, NMED initially proposed in the August 2024 Draft SIP emission rate limits based on SCR and emission rate limits of 1.81 lb/hr for unit 1 and 1.82 lb/hr for unit 2. *See id* at 3. Based on its new cost assessment in the Revised SIP, however, NMED revised the emission rate limits to reflect installation of dry low-NOx combustion ("DLN"), with emission rate limits of 15 ppmvd @ 15% oxygen for each unit. *Id*.

Enterprise appreciates that NMED has responded in this manner to address one significant issue identified in the September 2024 Enterprise Comments—the NOx removal efficiency for SCR. The impact of this revision demonstrates the critical nature of the factors that go into the Department's cost assessment, as well as its consideration of other relevant issues under the CAA and state law. Making this single change to the NOx removal efficiency assumption has resulted in substantially different emission control determinations for the Enterprise facilities. While Enterprise supports the revisions to the SIP and NMED's decision to replace its 90% NOx removal efficiency with 80% removal efficiencies for the Enterprise facilities, it is important to note several important further considerations:

- First, the NOx removal efficiency NMED adopted is at the high end of the 65% to 80% range recommended by Enterprise and its vendor. A more conservative approach, which Enterprise supports, would yield even higher costs.

- Second, additional real-world costs associated with installation of controls, and SCR in particular, will further increase control costs beyond NMED's current estimates.

- Third, consideration of factors beyond cost, including visibility, support further revisions to the SIP and elimination of additional control requirements for the Enterprise facilities.

For these reasons and the reasons stated in the previously submitted September 2024 Enterprise Comments, although Enterprise supports the action taken in the Revised Draft SIP, Enterprise believes additional revisions are nevertheless required. Full consideration of the relevant factors, as required by the CAA, and the most accurate, site-specific information should make clear that additional controls for the Enterprise facilities are not needed to address the CAA's "reasonable progress" requirement for the second planning period of the regional haze program.

II. NMED Should Revise the Emission Rate Limits to Provide Greater Compliance Flexibility for the Enterprise Facilities.

Enterprise explained in its comments on the August 2024 Draft SIP that NMED's proposal would have unnecessarily imposed unit-by-unit emission rate limits for each of the Enterprise facilities. September 2024 Enterprise Comments at 24. Enterprise requested that NMED revise those individual unit limits to allow for facility-wide averaging. *Id*. The Revised Draft SIP, however, continues to apply emission rate limits on a unit-by-unit basis. Revised Draft SIP at 144-46, App. G at 2-3. The Revised Draft SIP does not address Enterprise's request or the possibility of facility-wide averaging.

Despite NMED's revisions, the Revised Draft SIP continues to contain unsupported control determinations for the Enterprise facilities. In particular, for the reasons explained in these comments in the September 2024 Enterprise Comments, Enterprise believes the record does not support imposing emission rate limits for either the Blanco units based on SCR or for the South Carlsbad units based on DLN. Nevertheless, should NMED continue to support such an approach with regard to these units, Enterprise requests that NMED provide a facility-wide emission rate. Such a rate will achieve the same environmental benefits as unit-by-unit rates, while providing for additional, necessary compliance flexibility.

Accordingly, consistent with the current provisions of the Revised Draft SIP, NMED should further revise the emission rate limits applicable to the Blanco units to provide for a facility-wide emission rate limit of 50.58 lbs/hr, which is derived from summing the unit-by-unit rates contained in the Revised Draft SIP. Likewise, for South Carlsbad, a facility-wide weighted average rate of 15 ppmvd @ 15% oxygen (the rate that would be applicable to both South Carlsbad units individually), would allow for additional compliance flexibility without sacrificing overall environmental impact.

As explained in the September 2024 Enterprise Comments, allowing for compliance in this manner is fully consistent with the state's legal authority under the regional haze program, and similar approaches have been adopted in other states and approved by EPA to address reasonable progress requirements in the past. *See* September 2024 Enterprise Comments at 24. Enterprise therefore encourages NMED to adopt this approach.

III. NMED's Revised Cost Calculations for the Enterprise Facilities Are More Reasonable but Still Require Further Adjustment.

The most significant changes contained in the Revised Draft SIP relate to NMED's adjustments to its cost-effectiveness determinations, including its cost-effectiveness findings for the Enterprise facilities. Enterprise supports these changes.

For Blanco, the Revised Draft SIP increases the cost-effectiveness values for water steam injection controls, SCR, and unit replacement for units T-C01 and T-C02, and increases the values for SCR and replacement for unit T-D01. Revised Draft SIP at 120. Using these the revised cost-

effectiveness values, the Revised Draft SIP retains NOx emission control requirements for the Blanco units that are based on SCR. *Id*.

For Chaco, in relevant part, the Revised Draft SIP increases the values for DLN, SCR, and replacement for units 35, 36, and 37.[1] *Id*. at 122. Based on these revised values, the Revised Draft SIP eliminates emission control requirements based on SCR for units 35, 36, and 37. *Id*.

For South Carlsbad units 1 and 2, NMED revised the cost-effectiveness estimate for SCR and unit replacement. *Id*. at 123. As a result of its updated cost-effectiveness determinations, the Revised Draft SIP would require emission reductions based on DLN rather than SCR, based on NMED's finding that DLN would achieve greater emission reductions than SCR for these units. *Id*. at 123-24.

As noted above, the changes in cost-effectiveness values for SCR derive primarily from NMED's changes to the assumed control efficiency for SCR. *See id*. at 148.[2] NMED has included in its Four-Factor Analyses and Control Measures Determinations Technical Support Document (Appendix C to the Revised Draft SIP) a new statement:

> [F]or units that operate intermittently, such as natural gas compressor drivers, NOx removal efficiency may be lower due to decreased efficiency when the system is below the optimum temperature following cold starts. Depending on such a unit's annual operating profile, the average NOx removal efficiency of SCR could reasonably vary from approximately 75 to 85 percent.

Revised Draft SIP at 319.[3] That document further indicates that NMED revised the assumed NOx removal efficiency for the Enterprise facilities from 90% to 80%. *Id*. at 373, 382, 392.

Although Enterprise supports NMED's decision to revise the NOx removal efficiencies for the Enterprise facilities and the corresponding changes to the Revised Draft SIP's control determinations and emission rate limits, this single change to NMED's cost assessment does not adequately capture the full array of real-world costs that the Revised Draft SIP would impose on the Enterprise facilities, nor does this change adequately respond to Enterprise's September 2024 Comments.

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[1] The Revised Draft SIP also adjusts control costs for units 12, 13, 13, 17, and 18, but NMED's analysis based on these revised control costs did not change the Department's determination that these units do not require additional control requirements. *See* Revised Draft SIP at 122.

[2] Additional changes to the cost-effectiveness values, including those unrelated to SCR systems, appear to result from changes to "the methodology used for adjusting estimated costs from previous year dollars to 2023 dollars based primarily on feedback from industry." *Id*. at 191.

[3] Appendix C of the Revised Draft SIP is not paginated, so these comments refer to the page number of the PDF file containing the complete Revised Draft SIP and its appendices.

In its September 2024 Comments, Enterprise explained that it had received information from a vendor indicating that SCR was likely to be able to achieve NOx removal efficiencies of between 60 percent and 80 percent at the Enterprise facilities. September 2024 Enterprise Comments at 22. Those estimates were consistent with EPA technical guidance that suggests that removal efficiencies for SCR range from 65 to 90 percent across a wide scope of industries. *See id*. NMED's cost-effectiveness values for SCR would increase even further if it adopted a lower removal efficiency assumption, which would be a reasonable and conservative approach.

Moreover, just as adjusting NMED's cost estimates to reflect an 80 percent removal efficiency has had significant impacts on the Department's assessment of the cost-effectiveness of SCR for the Enterprise facilities, including in the analysis the additional costs associated with site complexities would similarly increase costs and impact NMED's cost-effectiveness analysis. Those costs have not been adequately taken into account by NMED in the Revised Draft SIP.

To attempt to address the lack of site-specific information in the record regarding the costs and feasibility of constructing SCR systems at the Enterprise facilities, Enterprise provided preliminary vendor data to NMED in the September 2024 Enterprise Comments. *Id.* at 20-21. As noted at that time, the vendor data Enterprise was able to obtain during the comment period was incomplete and reflected a number of necessarily conservative assumptions. *Id*. Even with those limitations (including those related to site complications and adequate power supplies), the preliminary vendor information submitted by Enterprise indicated that NMED had underestimated costs for the Enterprise facilities in the August 2024 Draft SIP, in some cases substantially.

Enterprise has continued to seek additional, detailed vendor data on costs. As a result of the Revised Draft SIP and its new control requirements, Enterprise will continue to work with vendors to acquire the most detailed and accurate estimates possible. It is all but certain, however, that the data Enterprise will receive will confirm that the Revised Draft SIP's cost estimates and its cost-effectiveness determinations, while improved, remain unrealistic and require further revision. Consistent with section VI of these comments, Enterprise will present the best available information at the time of the hearing on the Revised Draft SIP before the Environmental Improvement Board, or earlier, as appropriate.

IV. The Revised Draft SIP Does Not Correct NMED's Inadequate Evaluation of Visibility Impacts.

Enterprise previously noted that "NMED did not directly consider the visibility benefits of potential control measures when making its control determinations," and instead merely assumed that reductions in sulfur dioxide ("SO_2") and NOx emissions would result in visibility improvements at affected Class I areas. *See* September 2024 Enterprise Comments at 6-7 (quoting August 2024 Draft SIP). As Enterprise explained, the failure to consider visibility impacts violates the CAA, which requires consideration of visibility impacts when states develop SIP measures to address regional haze. *Id*. This failure further violates New Mexico law, which requires the Environmental Improvement Board consider visibility when making control determinations. *See id*.

Unfortunately, as reflected in the Revised Draft SIP, NMED continues to assume – rather than conduct the full evaluation of visibility impacts the CAA and New Mexico law requires – that visibility improvements will occur as a result of its control determinations. Revised Draft SIP at 109-110. While the Department has included limited additional information on visibility in the Revised Draft SIP such as summaries of visibility conditions, expressed in deciviews ("dv"), for the most impaired days in the baseline period, natural conditions, and conditions under the uniform rate of progress, *id*. at 55-62, this additional information does not place the expected visibility improvements of various control options into context, nor does it provide a basis for concluding that the visibility improvements that would be expected from implementation of the SIP will be meaningful, or that the visibility improvements otherwise justify or support the control determinations contained in the Revised Draft SIP.

For the reasons stated in the September 2024 Enterprise Comments, The Revised Draft SIP rests on an unsound and unreasonable approach to assessing visibility. NMED should further amend the Revised Draft SIP to fully assess the visibility impacts of the considered control options. Enterprise believes such an evaluation will support the conclusion that additional controls for the Enterprise facilities are not required to address reasonable progress under the CAA's regional haze program.

V. The Revised Draft SIP Does Not Provide Sufficient Justification for NMED's Q/d Screening Threshold.

NMED continues to rely on a Q/d assessment in the Revised Draft SIP to identify sources with emissions significant enough to warrant further evaluation pursuant to the CAA's four reasonable progress factors. *Id*. at 93. In the September 2024 Enterprise Comments, however, Enterprise explained that the Q/d threshold NMED adopted was unreasonably low and should be revised to be consistent with the actions of most other states and EPA guidance. *See* September 2024 Enterprise Comments at 13-15. NMED has not responded to these comments in the Revised Draft SIP. Instead, NMED has included additional information on the sources that it did not select for analysis based on their Q/d values. *See* Revised Draft SIP at 96-101. It has further included additional calculations intended to demonstrate that NMED's Q/d threshold of 5.6 "captures 80% of the total NOx and SO_2 emissions from all New Mexico Title V facilities." *Id*. at 93. But the NMED Q/d threshold is based on draft EPA guidance that EPA never finalized and decided against recommending when it issued its final guidance. *See* September 2024 Enterprise Comments at 15. The basis for NMED's Q/d threshold therefore remains flawed and unsupported despite the additional information included in the Revised SIP.

Had NMED adopted a more reasonable Q/d threshold, it is likely that at least several of the Enterprise facilities that are addressed in the Revised Draft SIP would not have been selected for additional analysis pursuant to the four reasonable progress factors. Indeed, the Q/d values, as stated in the Revised Draft SIP are: 7.81 dv for Blanco; and 5.91 dv for South Carlsbad. *See* Revised Draft SIP at 97. A screening threshold of 10, as many states have adopted, would have reasonably excluded these facilities. *See* September 2024 Enterprise Comments at 13-14.

The Q/d screening threshold used by NMED in the Revised Draft SIP conflicts with EPA recommendations and the threshold adopted by many states, and NMED does not provide adequate justification to support its use. NMED should further revise the SIP to adopt a Q/d screening threshold consistent with the majority of states and EPA's guidance, and amend the SIP's control requirements accordingly based on the revised Q/d screening threshold.

VI. The Abbreviated Comment Period Has Limited Enterprise's Ability to Develop New Information in Response to the Revised Draft SIP.

As stated above, Enterprise appreciates NMED's decision to adjust the NOx removal efficiency assumption used in its cost assessments for the Enterprise facilities and NMED's efforts to revise the SIP accordingly. Enterprise received notice of the Revised Draft SIP on December 13, 2024, at which time, NMED established a twenty-one-day comment period that ran over the holidays, ending on January 3, 2025. NMED subsequently extended that deadline to January 7, 2025.

Enterprise is continuing to review and assess the Revised Draft SIP. Because of the limited time to review and develop comments, Enterprise reserves its right to present additional information during review of the SIP by the Environmental Improvement Board and will submit this information to NMED once it is available.

CONCLUSION

For the foregoing reasons and the reasons stated in the September 2024 Enterprise Comments included here as Attachment A, the Revised Draft SIP, while improved, will continue to impose unwarranted emission control requirements on Enterprise's facilities if finalized. Although the Revised Draft SIP more reasonably addresses the NOx removal efficiency associated with SCR for the Enterprise facilities, and makes corresponding changes to the SIP's requirements for the Enterprise facilities, additional revisions are nevertheless warranted.

* * *

Should you have any questions regarding this submittal, please contact Tucker Jacobson at (713) 381-4313 (wtjacobson@eprod.com) or Bradley Cooley at (713) 381-5828 (bjcooley@eprod.com).

Sincerely,
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Attachment A

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September 20, 2024

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Comments of Enterprise Field Services, LLC on NMED's Draft Regional Haze State Implementation Plan Revision and 20.2.68 NMAC - Regional Haze Requirements

Dear Mr. Jones:

Enterprise Field Services, LLC ("Enterprise") submits herein to the New Mexico Environment Department ("NMED") comments on NMED's draft State of New Mexico Regional Haze State Implementation Plan Revision Second Planning Period (2019-2028) ("Draft SIP") and 20.2.68 NMAC – Regional Haze Requirements ("Companion Rule").

I. Introduction

On August 26, 2024, the NMED announced the release of a Draft SIP to address the Clean Air Act's ("CAA") regional haze requirements for the second planning period of the program (2018-2028). NMED established a comment deadline of September 20, 2024 for these proceedings.[1]

Enterprise is the owner and operator of three facilities that would be subject to the Draft SIP:

- South Carlsbad Compressor Station located in Eddy County, New Mexico (South Carlsbad) – located approximately 26 miles from the nearest Class I Area

[1] *See* NMED, Regional Haze Planning, https://www.env.nm.gov/air-quality/reg-haze/.

- Blanco C & D Compressor Station located in San Juan County, New Mexico (Blanco) – located approximately 39 miles from the nearest Class I Area

- Chaco Gas Plant located in San Juan County, New Mexico (Chaco) – located approximately 49 miles from the nearest Class I Area[2]

Throughout the development of the Draft SIP, Enterprise has engaged with NMED, providing information to support the state's four-factor analyses, responding to information requests, and proposing reasonable regulatory approaches. The Draft SIP, however, takes a very different approach than NMED appeared to be considering during these discussions. Despite indications that NMED agreed with Enterprise that selective catalytic reduction ("SCR") for the control of oxides of nitrogen ("NOx") was not feasible at the Enterprise facilities, the Draft SIP would impose emission limits for eight (8) of the thirteen (13) Enterprise units evaluated that are based on installation and operation of SCR.

NMED has not appropriately evaluated "reasonable progress," as defined by the CAA, for the Enterprise facilities addressed in the Draft SIP. As described in these comments, the Draft SIP is based on an incorrect determination of SCR's technical feasibility and faulty and unrealistic cost assumptions. Further, the SIP would impose control requirements to satisfy the CAA's reasonable progress standard without considering visibility improvement in any meaningful way. Failure to consider visibility and to take all of the statutory factors into account when devising the control requirements for the Enterprise facilities is arbitrary and capricious and contrary to the requirements of the CAA. For all of these reasons, Enterprise requests that NMED withdraw the Draft SIP, reconsider its analysis consistent with these comments, and develop more reasonable and better-supported control requirements for the Enterprise facilities.[3]

II. Background on the Regional Haze Program

The CAA's visibility protection provisions establish as a national goal "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas[4] which impairment results from manmade air pollution." CAA § 169A(a)(1). The Act directs the U.S. Environmental Protection Agency ("EPA") to issue regulations designed "to assure … reasonable progress toward meeting the national goal" and to require each state to submit a SIP containing "such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal." *Id*. § 169A(a)(4), (b)(2). Accordingly, pursuant to CAA section 169A, the ultimate requirement

[2] Collectively, the "Enterprise facilities."

[3] If NMED plans to proceed to seek approval of the Draft SIP, Enterprise requests, in the alternative, that NMED submit a partial SIP, excluding the Enterprise facilities, to allow Enterprise and NMED to work together to develop a separate SIP submittal that more appropriately addresses the Enterprise facilities.

[4] Class I federal areas are specified units of federal land receiving special protections, such as National Parks and Wilderness areas.

states must satisfy with their regional haze SIPs is to provide for "reasonable progress" towards the national visibility goal.

EPA implements the regional haze program in successive ten-year "planning periods." The first planning period ran from 2008 to 2018. The second planning period of the program covers the period from 2018 to 2028. SIPs to address second planning period control requirements were due to EPA by July 31, 2021. 40 C.F.R. § 51.308(f). As NMED notes in its announcement of the availability of the Draft SIP, EPA "is currently under a September 29, 2024 deadline to approve New Mexico's regional haze plan or promulgate a federal plan for New Mexico satisfying the visibility protection requirements of the Clean Air Act."[5] That deadline, negotiated with environmental groups, is already well past the July 31, 2021 regulatory deadline for second planning period regional haze SIPs. 40 C.F.R. § 51.308(f).

A regional haze SIP has a number of required elements. Most importantly for purposes of these comments, regional haze SIPs must include: (1) technical analyses to inform and support the SIP's control determinations, including calculation of visibility conditions, development of the "uniform rate of progress" ("URP") for each of the state's Class I areas, and interstate and Federal Land Manager ("FLM") consultation demonstrations; (2) a Long-Term Strategy ("LTS"), which includes measures necessary to make reasonable progress toward the national visibility goal; and (3) reasonable progress goals ("RPGs"), which are visibility goals for each mandatory Class I federal area located in the state and which are based on the control measures included in the LTS.

The CAA and EPA's regional haze rule ("RHR") require states to evaluate potential control requirements for sources within their jurisdiction using the four reasonable progress factors: "[1] the costs of compliance, [2] the time necessary for compliance, [3] the energy and non-air quality environmental impacts of compliance, and [4] the remaining useful life of any potentially affected sources." *Id*. § 51.308(f)(2)(i). If a four-factor analysis supports the establishment of new control requirements, those requirements may be appropriate for inclusion in the state's regional haze SIP. Under certain conditions, a state may be required to include existing control measures in their regional haze SIPs to ensure that the state continues to make reasonable progress.

EPA guidance establishes that states may consider visibility alongside the four statutory factors when evaluating controls, stating "EPA has interpreted the CAA and RHR as allowing states to consider visibility alongside the four statutory factors when determining the emission reduction measures that are necessary to make reasonable progress."[6] In fact, EPA "anticipate[s] that the outcome of the decision-making process by a state regarding a control measure may most often depend on how the state assesses the balance between the cost of compliance and the

[5] https://www.env.nm.gov/air-quality/reg-haze/.

[6] EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period at 12 (July 8, 2021) ("Clarifications Memo").

visibility benefits."[7] Moreover, as discussed above, the CAA requires states to make reasonable progress determinations that are tied by law to consideration of the national visibility goal.

In addition, under the RHR, states must determine and take into account URP, *i.e.*, the rate of progress that would be needed to attain natural visibility conditions by the year 2064, assuming consistent progress is maintained from the baseline to the program's aspirational endpoint. *Id*. § 51.308(f)(3)(ii)(A). Under the RHR, a state may establish an RPG that differs from the URP if the state demonstrates that the URP for the Class I area in question would not be reasonable. A state makes such a showing by conducting a reasonable progress analysis that considers the four reasonable progress factors and makes a "robust" demonstration. *Id*.[8] The RHR also allows states to adjust the URP to account for the effects of international emissions and emission from prescribed fires on wildlands. 40 C.F.R. § 51.308(f)(1)(vi)(B).

States whose emissions may cause visibility impairment in another state's Class I area and states with Class I areas that may experience visibility impairment caused by emissions from other states may be subject to an interstate-consultation requirement. *Id*. § 51.308(f)(2)(ii). The purpose of that requirement is to provide a forum for states to decide collaboratively on reasonable emission reductions and appropriate apportionment of responsibility for reducing emissions during each planning period of the regional haze program. In addition, all states are subject to a requirement to consult with the FLMs in the development of their SIPs. *Id*. § 51.308(i).

III. The New Mexico Environment Department Has Not Adequately Engaged with the Regulated Community.

During the development of the Draft SIP, Enterprise undertook extensive work to assist in the preparation of four-factor analyses for the Enterprise facilities. Enterprise further submitted written materials explaining potential legal and policy justifications to support the state's reasonable progress determinations. To further those efforts, Enterprise met multiple times with NMED staff. Enterprise worked with the state to understand its process, the emission controls under consideration, and the information NMED needed to make informed reasonable progress determinations. As noted in Appendix C, this engagement included:

- The FFA completed by Trinity Consultants for Enterprise Field Services, LLC (Enterprise) and submitted to NMED on 10/30/19 and 11/14/19, respectively.
- Additional information provided by Enterprise on 2/14/20, 2/26/20, 5/19/20, 6/2/20, 9/8/20, 10/1/20, 3/4/21, and 8/30/23.
- Detailed discussions between Enterprise and NMED on 8/28/20 and 7/13/23.

[7] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 37 (Aug. 20, 2019) ("2019 Guidance").

[8] The statutory basis for EPA's "robust" demonstration requirement is, at best, unclear.

• Written comments submitted to NMED regarding Draft Final Cost Evaluations on 1/15/24.[9]

In addition to the engagement described above, Enterprise, in a February 19, 2020 presentation given to NMED, explained using aerial photographs that there was insufficient space available for SCRs at each of the Enterprise facilities.[10] At no time during the many interactions since that presentation did NMED indicate that it was evaluating SCR for the Enterprise facilities or that it had reason to reject Enterprise's assertions as to the problems posed by space constraints. On the contrary, in an email dated December 20, 2023, NMED provided Enterprise with " draft final cost evaluations" for the Enterprise facilities to facilitate Enterprise providing comments on those cost evaluations.[11] Two spreadsheets containing the state's cost analysis were attached to this email and indicated that NMED had concluded that, due to space constraints, other site-specific factors, and costs for other similar facilities in New Mexico, "SCR is cost prohibitive" for the Enterprise facilities.[12]

Despite all of this early engagement, NMED has now released its Draft SIP with vastly different conclusions as to the feasibility of SCR and would impose especially stringent emission rate limits on the Enterprise facilities as a result. Had NMED shared with Enterprise that it was considering a significant change in course, Enterprise would have worked to provide the state with additional information to further assist in its assessment of SCR. Unfortunately, Enterprise did not have that opportunity. Similarly, NMED has now provided only a 25-day period for comment on the Draft SIP. Although Enterprise understands that the regulatory process in New Mexico will provide additional opportunities to participate, by failing to transparently engage with Enterprise during development of the Draft SIP, NMED has substantially limited Enterprise's ability to develop and provide much-needed information to correct the record in these proceedings.

In the limited time available, Enterprise has developed the analysis presented here, which further demonstrates the significant costs of SCR for the Enterprise facilities. Because NMED is using SCR as the basis of the NOx limits, as expressed in the Companion Rule, and due to the limited time available to evaluate SCR, Enterprise has not been able to quantify the full scope of facility modifications, with their attendant cost, complexity, and uncertainty, that would be needed to attempt to achieve the proposed NOx limits. This would have required a full constructability evaluation as well as an analysis of infrastructure reconfiguration and potential electrical upgrade requirements. Enterprise appreciates that NMED has committed to considering any additional information that may be developed subsequent to the close of the current

[9] Draft SIP, App. C at 65. For ease of reference, Citations to NMED Appendices refer to the PDF pagination rather than the pagination of the individual reports contained therein.

[10] Enterprise Products Partners, L.P., Regional Haze Planning Meeting (February 19, 2020) (Attachment A). Similar images appear in the Draft SIP, App. D at 500-501, 597, 657.

[11] NMED, Email Correspondence and attachments (Dec. 20, 2023) (Attachment B).

[12] *Id*. at attachments, SCR Tab.

comment period and to reasonably accommodate the need for additional time that may be needed to complete complex analyses and to obtain information from third parties.

The information that is available makes clear that SCR is not necessary to make reasonable progress when considered in light of the four factors and the limited visibility improvement that could be achieved through installing these controls. Accordingly, just as Enterprise has worked diligently in very short time to provide NMED with information that necessitates revising the Draft SIP's requirements for the Enterprise facilities, NMED must revise the Draft SIP before submitting it for review by the state's Environmental Improvement Board ("EIB"). Indeed, proceeding to seek approval of the Draft SIP after consideration of the information provided in these comments would be unreasonable and unsupported by the record. Accordingly, NMED should withdraw the Draft SIP or substantially revise it based on these comments before proceeding with EIB review.[13]

IV. New Mexico Has Unreasonably Refused to Consider Visibility in Violation of the CAA.

As explained above, section 169A of the CAA imposes one overarching requirement on states: they must include in their SIPs "such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal." 42 U.S.C. § 7491(b)(2). The national goal that states must ensure "reasonable progress" towards is a visibility goal: "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." *Id*. § 7491(a)(1). While states must consider the four reasonable progress factors when assessing the level of progress that is reasonable, plainly, states cannot make a determination as to the measures needed to ensure reasonable progress without considering the overall goal of the program.[14] Thus, as should be clear, a regional haze SIP must be based on consideration of visibility to satisfy the CAA.

In describing how it selected control requirements for sources subject to the SIP, NMED says:

> NMED did not directly consider the visibility benefits of potential control measures when making its control determinations. EPA has

[13] If, in spite of these comments, NMED intends to proceed with finalizing the Draft SIP without appropriate revisions, Enterprise requests that NMED provide Enterprise with the opportunity to respond to any of the Department's remaining questions and to provide any necessary additional information. As noted above in footnote 3, addressing the Enterprise facilities in a separate SIP submittal could provide NMED with additional time to respond to these comments (as well as any additional information that is developed) while still proceeding with approval of the remainder of the Draft SIP.

[14] In its Clarifications Memo, EPA appears to assert that states may only consider visibility in certain ways or for certain purposes. Clarifications memo at 13. For instance, EPA says visibility should not be used to "summarily dismiss" cost-effective controls, but that it could be used to select among different cost-effective controls. *Id*. EPA has presented no principled basis for limiting consideration of visibility. Moreover, as described above, the CAA must be interpreted to require consideration of visibility in support of measures needed to make reasonable progress under the regional haze provisions of the Act.

> consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making control determinations. NMED's approach is based on the assumption that substantial reductions in emissions of NOx and SO_2 will translate into visibility benefits.

Draft SIP at 104-05. According to NMED, therefore, the state did not consider visibility other than to assume that emission reductions would translate to visibility benefits, essentially failing to consider visibility at all. This is an unreasonable approach to developing a regional haze SIP, and it is inconsistent with the requirement that states develop SIPs that ensure reasonable progress toward the national visibility goal. In short, failure to consider visibility is a failure to consider a factor Congress intended states to take into account when developing regional haze SIPs. NMED has therefore failed to consider "an important aspect of the problem," which renders the Draft SIP arbitrary and capricious under the law. *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43, (1983) ("Normally, an agency rule would be arbitrary and capricious if the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise.")

In addition, New Mexico law requires that the EIB consider visibility when taking action. NM Stat § 74-2-5(f) (2023). The EIB is tasked with weighing visibility improvements against "the public interest, including the social and economic value of the sources and subjects of air contaminants;" as well as "technical practicability and economic reasonableness of reducing or eliminating air contaminants from the sources involved and previous experience with equipment and methods available to control the air contaminants involved." *Id*. The EIB cannot fulfill its statutory obligations without an assessment of visibility by NMED. On the contrary, in the absence of a visibility assessment in support of the Draft SIP, the EIB will have no choice but to disapprove it for failure to comport with the CAA minimal requirements.[15]

NMED must correct this shortcoming in the Draft SIP before proceeding to seek approval from the EIB. A proper consideration of visibility, moreover, as described in the next section, demonstrates that existing controls at the Enterprise facilities are sufficient to address the CAA's reasonable progress requirement for the second planning period and that SCR cannot be justified.

V. Any Reasonable Assessment of Visibility Demonstrates that Additional Controls, Including SCR, Cannot Be Justified for the Enterprise Facilities.

All evidence in the record supports a finding that visibility conditions in Class I areas potentially affected by the Enterprise facilities are already achieving reasonable progress. The evidence in the record further establishes that any new emission control requirements for the

[15] While the technical information included in the Draft SIP on visibility conditions is useful information, without analysis of visibility impacts and an assessment of how such impacts should figure into control determinations by NMED in the first instance, the EIB will not have an adequate basis on which to evaluate the Draft SIP.

Enterprise facilities will result in, at most, imperceptible visibility impacts. In short, considered by every metric, the visibility effects that would result from the requirements of the Draft SIP cannot support the imposition of costly new control requirements. As such, the Draft SIP should be revised to recognize that existing controls at the Enterprise facilities are sufficient to ensure reasonable progress.

The progress achieved to date and projected for the future without requiring additional controls, including SCR, at the Enterprise facilities should be deemed sufficient to address the reasonable progress requirement for the second planning period. The Draft SIP acknowledges, for instance, that all Class I areas affected by New Mexico sources "have shown visibility improvement over the monitoring period." Draft SIP at 42. This improvement, when compared to the URP, demonstrates that the areas affected by New Mexico sources are generally improving faster than the URP metric. The Draft SIP explains:

> NMED's glidepath checks show that eight of New Mexico's nine Class I Areas are projected to fall below the URP glidepath in 2028, which is indicative of a faster rate of improvement than the URP. Only Salt Creek Wilderness Area in Chaves County is projected to be above the glidepath, indicating a slower rate of improvement than the URP.

Draft SIP at xiii. Despite devoting a chapter of the Draft SIP to describing the results of its comparison of the URP to visibility conditions, NMED fails to draw any conclusions or present any analysis of how it took the performance of these Class I areas relative to the URP into account in evaluating requirements for the Draft SIP. Indeed, it does not appear that NMED actually took the URPO into account in any way. NMED must include such an analysis to satisfy the requirements of the RHR and to provide a well-supported SIP. Any reasonable assessment of the URP, moreover, supports the conclusion that additional controls for the Enterprise facilities, including SCR, are not needed for reasonable progress.[16]

In each of the four-factor assessments that Enterprise submitted to NMED to assist in the development of the Draft SIP, Enterprise's consultant included an assessment of likely visibility impacts that would result from controls at the Enterprise facilities. For Blanco, Enterprise reported:

> The Blanco C&D Compressor Station is located approximately 50 miles from the Mesa Verde Class I areas at a wind vector range of approximately 155 degrees to 165 degrees (SSE). According to 2015 meteorological data collected in Bloomfield, NM . . . wind blows from this direction range at a frequency of only 2.4%.

[16] As explained below, although Salt Creek Wilderness Area is not yet projected to be below the URP glidepath, a Q/d assessment for South Carlsbad using recent emissions data shows that its emissions would have minimal impacts on visibility that fall below NMED's screening threshold for bringing sources forward for four-factor analysis.

> Moreover, when the wind direction is within this range, the wind speed is typically relatively low; the frequency of wind speeds greater than 3.09 m/s (or ~7 mph) is only 0.3%, or about 25 hours per year. Higher wind speeds would be needed to effectively transport emissions from Blanco to the Mesa Verde Class I area. Moreover, over the 50 miles of transport, pollutants undergo significant dispersion. While full dispersion and photochemical modeling would be needed to more robustly evaluate Blanco's impact, based on this evidence, Blanco's impact on visibility is likely insignificant.

See Draft SIP, App. D. at 488.

Similarly, for Chaco, Enterprise reported:

> The Chaco Gas Plant is located approximately 50 miles from the Mesa Verde Class I area at a wind vector range of approximately 155 degrees to 165 degrees (SSE). According to 2015 meteorological data collected in Bloomfield, NM . . . wind blows from this direction range at a frequency of only 2.4%. Moreover, when the wind direction is within this range, the wind speed is typically relatively low; the frequency of wind speeds greater than 3.09 m/s (or ~7 mph) is only 0.3%, or about 25 hours per year. Higher wind speeds would be needed to effectively transport emissions from Chaco to the Mesa Verde Class I area. Moreover, over the 50 miles of transport, pollutants undergo significant dispersion. While full dispersion and photochemical modeling would be needed to more robustly evaluate Chaco's impact, based on this evidence, Blanco's impact on visibility is likely insignificant.

Id. at 581.

For South Carlsbad, Enterprise reported:

> The South Carlsbad Compressor Station is located approximately 16.2 miles [sic][17] from the Carlsbad Caverns Class I area at a wind vector range of approximately 60 degrees to 70 degrees (NE). According to 2017 meteorological data collected in Carlsbad. . . wind only blows from this direction at a frequency of 1.4% or approximately 120 hours per year. Moreover, over the 16 miles of transport, pollutants would undergo significant dispersion. While

[17] The distance is 25.88 km (16.1 miles) according to SIP table 6-1. Draft SIP at 96.

> full dispersion and photochemical modeling would need to be conducted to more accurately evaluate South Carlsbad's impact, based on this evidence, the facility's impact on visibility is likely insignificant.

Id. at 644.

As explained above, NMED has not conducted any additional visibility assessment or reached any conclusions about the impact of the Enterprise facilities on visibility in Class I areas. Accordingly, the only information in the record supports the conclusion that the impacts from the controls under evaluation are not likely to be meaningful. NMED cannot nevertheless impose emission control requirements without even considering this crucial information, much less carefully weighing it.

Since preparation of the NMED and Enterprise four-factor assessments, additional data has become available to demonstrate that visibility impacts from Chaco and South Carlsbad—and any benefit that would result from further controlling their emissions—have grown even smaller. As shown in the table below, since 2016, emissions from Chaco and South Carlsbad have generally fallen, with resulting Q/d values falling appreciably as well. Most significantly, the Q/d values for South Carlsbad for four of the last five years have been below the state's adopted Q/d threshold of 5.6. This is adequate grounds in itself to remove control requirements for South Carlsbad from further consideration.

	Blanco		Chaco		South Carlsbad	
Year	Q	Q/d	Q	Q/d	Q	Q/d
2014	513.2	8.1	2250.0	28.0	149.5	5.8
2015	528.3	8.3	2175.6	27.1	160.3	6.2
2016	494.8	7.8	2270.7	28.3	153.0	5.9
2017	515.0	8.1	1943.9	24.2	156.5	6.0
2018	512.6	8.1	1976.2	24.6	160.0	6.2
2019	573.7	9.1	1829.2	22.8	133.8	5.2
2020	883.1	13.9	1861.0	23.2	135.6	5.2
2021	591.5	9.3	1826.9	22.8	140.2	5.4
2022	456.9	7.2	777.1	9.7	121.6	4.7
2023	658.7	10.4	707.6	8.8	156.7	6.1

Q = Sum of reported annual NOx and SO2 emissions (tons)

d = distance from Class I area (km) per Table 6-1 of draft SIP

Blanco =	63.4	km
Chaco =	80.2	km
S. Carlsbad =	25.9	km

Finally, the lack of a visibility assessment obscures the truly de minimis nature of the visibility impacts from the Enterprise facilities further demonstrating why refusing to consider visibility is unreasonable and inconsistent with the CAA. When EPA promulgated a Federal Implementation Plan ("FIP") to address regional haze for New Mexico during implementation of the first planning period of the program, EPA conducted a full visibility assessment to evaluate whether SCR could be justified. *See* 76 Fed. Reg. 491 (Jan. 5, 2011) (Proposed FIP for New Mexico). In determining that SCR could be justified for the San Juan Generating Station, EPA determined that the installation and operation of SCR would result in a visibility improvement of 21.69 deciviews across 16 different Class I areas. *Id*. at 503. Improvements within individual Class I areas ranged from 0.31 deciviews to 3.11 deciviews. *Id*. To put this context, EPA says that a 0.5 deciview impact "contributes" to visibility impairment, a 1.0 deciview impact "causes" visibility impairment, and a 1.0 deciview impact is generally the threshold for human perception of a change in visibility conditions. To further put this into perspective, to achieve this level of visibility improvement, EPA projected that the FIP would eliminate 17,518 tons per year of NOx. *Id*. at 502, Table 7.

By contrast, the Draft SIP's tons per year NOx reductions estimated for Blanco are 974.4 tons. Draft SIP at 115. For Chaco, they are 363.6 tons. *Id*. at 116. For South Carlsbad, they are 138.7. *Id*. at 118. The visibility benefits that might result from these reductions would be a mere fraction of those previously deemed sufficient to justify requiring SCR. Accordingly, the minimal visibility impacts that may result from emissions from the Enterprise facilities cannot reasonably serve as the basis for imposing the enormously costly, if not infeasible, emission controls contemplated in the Draft SIP.

A full and reasonable evaluation of visibility, as required by the CAA and New Mexico law, demonstrates that the Draft SIP's control determinations for the Enterprise facilities are unsound and must be revised. The only information in the record supports the conclusion that the visibility impacts of the Enterprise facilities, and the visibility improvements that could be achieved with additional controls, do not support requiring additional costly requirements to address reasonable progress at this time. NMED is obligated to consider this information and to revise the requirements of the Draft SIP to better align the Draft SIP's requirements with the requirements of the CAA.

VI. New Mexico Has Failed to Justify Its Decision to Pursue Reductions in Nitrogen Oxides.

The Draft SIP explains that visibility impairment is overwhelmingly dominated by "ammonium sulfate, organic mass, and coarse mass on both the Most Impaired Days and the Clearest Days." Draft SIP at 53.[18] EPA guidance makes clear that it is appropriate for states to evaluate controls for the most significant visibility-impairing pollutants:

[18] The only exceptions are Salt Creek Wilderness and San Pedro Parks Wilderness, "when ammonium nitrate was one of the top three contributors instead of either organic mass or coarse mass." Draft SIP at 53. None of the Enterprise facilities is located near these areas or could reasonably be expected to influence their visibility conditions. Blanco is 471.14 kilometers ("km") from Salt Creek and 89.47 km from San Pedro. Chaco is 461.68 km

> When selecting sources for analysis of control measures, a state may focus on the PM species that dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors. Also, it may be reasonable for a state to not consider measures for control of the remaining pollutants from sources that have been selected on the basis of their emissions of the dominant pollutants.

2019 Guidance at 11. Had NMED followed this guidance and focused on the greatest pollutants of concern, the Enterprise facilities would not have even been considered for additional controls. This is itself an adequate basis for removing the Enterprise facilities from further consideration for reasonable progress controls.

EPA's guidance goes on to provide one pertinent example:

> For example, organic mass by carbon (OMC) light extinction might be dominant in the IMPROVE data for a western Class I area on the average of the 20 percent most anthropogenically impaired days, even though days heavily affected by fires will tend not to be included in the 20 percent most anthropogenically impaired days. This may cause sulfate to account for only a small percentage of total light extinction. However, it could be clear that most of the OMC is natural and that sulfate dominates anthropogenic light extinction. In this situation, we recommend that a state consider SO_2 sources and SO_2 control measures.

This is the situation facing New Mexico. Yet instead of focusing on SO_2 controls, as the data suggests would be appropriate and a*s EPA guidance calls for*, the state has unreasonably focused on the negligible impacts that might result from NOx emissions, including the relatively small NOx emissions from the Enterprise facilities.

New Mexico rationale for pursuing NOx reductions is that "[t]he largest haze reductions over time (i.e., the largest reduction in individual species' contributions to light extinction) are generally associated with ammonium sulfate and ammonium nitrate, which have likely occurred due to reduced SO_2 and NOx emissions since EPA first promulgated the Regional Haze Rule in 1999." Draft SIP at 53. Although significant reductions in NOx in the past may have been associated with commensurate reductions in haze, there is no basis for concluding that eliminating minor amounts of NOx will have a significant effect on visibility at this time.

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from Salt Creek and 99.97 km from San Pedro. South Carlsbad is 141 km from Salt Creek and 477.04 km from San Pedro.

Indeed, as described above, EPA's FIP for New Mexico for the first regional haze planning period would have eliminated 17,518 tons per year of NOx. *Id*. at 502, Table 7 and improved visibility by an appreciable 21.69 deciviews across 16 different Class I areas. 76 Fed. Reg. at 502-03. EPA withdrew that FIP and approved a subsequently submitted regional haze SIP for New Mexico that achieved *even greater* emission reductions and visibility improvements than the FIP. See Approval and Promulgation of Implementation Plans; New Mexico; Regional Haze and Interstate Transport Affecting Visibility State Implementation Plan Revisions, 79 Fed. Red. 60,985 (Oct. 9, 2014). The Draft SIP achieves nothing approaching this level of visibility improvement from its proposed NOx controls.

For all of these reasons, NMED has "offered an explanation for its decision [to focus on NOx] that runs counter to the evidence before the agency." *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43, (1983). New Mexico, consistent with EPA guidance, should elect to focus the current regional haze SIP on the visibility impairing pollutants of most significance. It should not continue to pursue NOx controls for this planning period. For that reason, NMED should revise the Draft SIP to acknowledge that existing controls at the Enterprise facilities are adequate to ensure reasonable progress.

VII. NMED Has Adopted an Unreasonable Q/d Screening Threshold.

The Draft SIP explains that NMED performed Q/d assessment to identify sources with emissions significant enough to warrant further evaluation pursuant to the four factors. Draft SIP at 93. NMED adopted a Q/d screening threshold of 5.6. *Id*.

This screening threshold is significantly out of step with the thresholds used by other states, including those that have previously been approved as reasonable for use in the regional haze program by EPA. Indeed, every state to adopt such a screening threshold appears to have adopted one substantially higher than New Mexico:

- Air Plan Partial Approval and Partial Disapproval; Wyoming; Regional Haze Plan for the Second Implementation Period, 89 Fed. Reg. 63,030, 63,042 (August 1, 2024) (screening threshold of Q/d > 10).

- Air Plan Partial Approval and Partial Disapproval; Utah; Regional Haze State Implementation Plan for the Second Implementation Period; Air Plan Disapproval; Utah; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 89 Fed. Reg. 67,208, 67,220 (August 19, 2024) (screening threshold of Q/d ≥ 6).

- Air Plan Approval; Wisconsin; Second Period Regional Haze Plan, 89 Fed. Reg. 65,492, 65,503 (August 9, 2024) (screening threshold of 10).

- Approval and Promulgation of Air Quality Implementation Plans; State of Florida; Regional Haze State Implementation Plan, 77 Fed. Reg. 31,240, 31,253

(May 25, 2012) (screening threshold of 50).

- Partial Approval and Disapproval of Air Quality Implementation Plans; Arizona; Regional Haze State Implementation Plan for the Second Implementation Period and Prong 4 (Visibility) for the 2015 Ozone and 2012 Particulate Matter Standards, 89 Fed. Reg. 47,398, 47,412 (May 31, 2024) (screening threshold of 10).

- Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan: Proposal of Best Available Retrofit Technology (BART) and Interstate Transport Provisions, 83 Fed. Reg. 43,586, 43,596 (Aug. 27, 2018) (screening threshold of 10).

- Approval and Promulgation of Air Quality Implementation Plans; Montana; Regional Haze Federal Implementation Plan, 82 Fed. Reg. 17,948, 17,955 (Apr. 14, 2017) (screening threshold of 10).

- Approval and Promulgation of Implementation Plans; South Dakota; Regional Haze State Implementation Plan, 76 Fed. Reg. 76,646, 76,661 (Dec. 8, 2011) (screening threshold of 10).

- Approval and Promulgation of Implementation Plans; State of Colorado; Regional Haze State Implementation Plan, 77 Fed. Reg. 18,052, 18,078 (Mar. 26, 2012) (screening threshold of 20).

The vast majority of similarly situated states have adopted screening threshold of 10 or higher. Such a threshold is consistent with EPA's BART Guidelines,[19] which provide:

> Based on our analyses, we believe that a state that has established 0.5 dv as a contribution threshold could reasonably exempt from the BART review process sources that emit less than 500 tons per year of NO—T2X or SO—T22 (or combined NO—T2X and SO—T22), as long as these sources are located more than 50 kilometers from any Class I area; and sources that emit less than 1000 tons per year of NO—T2X or SO—T22 (or combined NO—T2X and SO—T22) that are located more than 100 kilometers from any Class I area."

40 C.F.R. 51, appendix Y, section III, How to Identify Sources "Subject to BART." According to the BART Guidelines, therefore, a facility with minimal impacts such as these can reasonably be excluded from the regional haze program. As EPA explained in another final regional haze rule,

[19] Although the BART Guidelines are not binding in setting reasonable progress requirements, the BART Guidelines nonetheless provide useful precedent.

"[t]he values described [in the BART Guidelines] equate to a Q/D of 10." 82 Fed. Reg. at 17,955 n.53.

Had New Mexico adopted such a threshold, based on review of the most recent Q/d calculations, presented above, at least two of the three the Enterprise facilities (Chaco and South Carlsbad) should have screened out of further evaluation. For this reason alone, NMED should revise the Draft SIP to impose no additional control requirements for Chaco and South Carlsbad on this basis.

NMED has not offered a valid rationale for adopting such a low screening threshold. The explanation contained in the Draft SIP is that the threshold was intended:

> to capture 80% of the total NOx and SO_2 emissions from all New Mexico Title V facilities combined. NMED and EHD chose this 80% threshold based on guidance in the WRAP Source Selection Protocol. The Protocol noted draft guidance from EPA recommending an 80% threshold applied to emissions from all stationary sources.

Draft SIP at 92 (citation omitted). The draft guidance recommending an 80% threshold was never adopted by EPA. EPA instead issued the 2019 Guidance, which did not adopt the 80% threshold. Accordingly, NMED has adopted an extreme outlier screening threshold on the basis of guidance that was never adopted as formal EPA policy.

NMED should withdraw the Draft SIP and apply a more reasonable screening threshold, consistent with the actions of its sister states. It should further revise the Draft SIP to recognize that the visibility impacts of the Enterprise facilities are too small to justify imposing additional controls and are indeed, small enough to reasonably be screened out from a four-factor assessment.

VIII. NMED Has Failed to Adequately Consider Each of the Four Factors.

Under the CAA, states must consider four factors to determine reasonable progress: "the costs of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements." 42 U.S.C. § 7491(g)(1). Rather than fully consider each of the four factors, NMED has focused almost exclusively on cost, contrary to the CAA. The Draft SIP explains, "[c]ost effectiveness was the predominant factor in NMED's decision-making regarding necessary control measures, with the remaining factors either being subsumed into the cost of compliance or not being major considerations." Draft SIP at 104.

Although states have considerable discretion as to how they weigh the four statutory reasonable progress factors, states must, at a minimum, give reasonable consideration to each one. *See Nat'l Parks Conservation Ass'n v. McCarthy*, 816 F.3d 989, 992 (8th Cir. 2016) (states "must consider four factors").

NMED has not considered the disbenefits of SCR. Specifically, in evaluating SCR or any other control, the state must take into account "the energy and nonair quality environmental impacts of compliance" to satisfy the CAA's requirements. Operation of SCR will have at least four such impacts.

First, a disbenefit of SCR is ammonia ("NH_3") emissions. Based on approximate exhaust rates for the 8 Enterprise turbines for which NMED has proposed to require SCR, and an estimated 10 ppmv NH_3 slip, aggregate annual NH_3 emissions would be approximately 196 tons assuming no restriction in operating hours.

NH_3 Emissions (Annual)

Facility	Estimated NH_3 Emissions
Blanco	86.6 tons
Chaco	87.6 tons
S. Carlsbad	21.8 tons

Emissions of ammonia have a range of environmental impacts. *See generally* U.S. EPA. Integrated Science Assessment (ISA) for Oxides of Nitrogen, Oxides of Sulfur and Particulate Matter Ecological Criteria (Final Report, 2020). NMED has not considered this disbenefit.

Second, the SCR system will involve the use of hazardous materials. SCR can use either aqueous or anhydrous ammonia for the reduction reaction. Anhydrous ammonia is classified as a hazardous material and often requires special permits as well as additional procedures for transportation, handling and storage. Aqueous ammonia, on the other hand, requires more storage capacity than anhydrous ammonia. Both pose environmental and safety risks. Again, NMED has not considered this.

Third, operation of SCR requires power. Due to the limited amount of time to evaluate SCR as a control option for the Enterprise facilities, a feasibility and constructability evaluation has not been completed at the time of submittal. It is therefore unknown if existing electrical power is sufficient or if upgrading or adding electrical infrastructure would be required. NMED has not considered these energy impacts either.

Fourth, operation of SCR could impact engine performance by creating additional working load on the engine. A detailed engineering study could not be performed in the limited time available for public comment. It is therefore not known issue will impact the ability of the Enterprise facilities to meet commercial throughput requirements. This is also an energy impact that NMED is obligated to consider.

Before NMED can lawfully propose its reasonable progress and related emission control determinations, it must present an assessment of each of the four factors evaluating the use of the controls under consideration. NMED has not done that in support of its proposed SCR requirements for the Enterprise facilities. A proper and complete evaluation of "the energy and nonair quality environmental impacts of compliance" would, moreover, provide further support

for the conclusion that SCR is not needed to achieve reasonable progress and that the existing controls at the Enterprise facilities ensure that reasonable progress will be achieved during the second planning period of the regional haze program.

IX. NMED Has Unreasonably Concluded SCR Is Technically Feasible.

According to EPA's 2019 Guidance, "[t]he first step in characterizing control measures for a source is the identification of technically feasible control measures for those pollutants that contribute to visibility impairment." 2019 Guidance at 28. EPA's regulatory BART Guidelines for the regional haze program provides further information on the methodology for assessing control to address visibility. In the BART Guidelines, EPA explained:

> You should clearly document a demonstration of technical infeasibility and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. You may then eliminate such technically infeasible control options from further consideration….
>
> Alternatively, a demonstration of technical infeasibility may involve a showing that there are unresolvable technical difficulties with applying the control to the source (e.g., size of the unit, location of the proposed site, or operating problems related to specific circumstances of the source).

Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations, 66 FR 38108, 38,123-24 (July 20, 2001).

During development of the Draft SIP, Enterprise demonstrated to NMED that SCR was not a technically feasible control for the Enterprise facilities. Enterprise communicated to NMED that it had eliminated consideration of SCR as a feasible technology due to the current configuration and available space.[20] Enterprise provided vendor-supplied SCR dimensions as CBI to NMED in support of that assessment.[21] Maps were also provided in this response that overlayed the area required for SCR showing existing facility infrastructure.

NMED has not explained its reason for changing course with respect to the technical feasibility of SCR for the Enterprise facilities. All that NMED says in this regard is the following:

[20] *See* Draft SIP, App. D at 481-82, 494-502, 574, 589-598, 639, 651-661 (Various Enterprise four-factor analysis submittals).

[21] *Id*. (providing CBI materials to NMED).

> Enterprise asserted that limited physical space precludes the option of installing SCR and provided an aerial image with measurement overlays to support this assertion. However, the image provided suggests there is physical space for SCR if building modifications are made.

Draft SIP, App. C at 80. This minimal level of assessment is not sufficient to serve as a basis for finding that SCR is technically feasible. NMED must revise the Draft SIP to reflect this reality.

X. New Mexico's Cost Evaluation for the Enterprise Facilities Is Substantially Flawed.

To support its proposed control requirements for the Enterprise facilities, NMED focused predominately on costs. Draft SIP at 102 ("To characterize the cost of compliance, which was the predominant factor in NMED's decision-making regarding control measures…."). NMED considered a single cost metric: "cost effectiveness of each control, expressed in terms of cost per ton of emissions reduced." *Id*.

The regional haze program is intended to evaluate real-world, site-specific costs. NMED says that it made use of such information in a limited fashion:

> NMED utilized source-specific cost estimates provided by the facilities in its calculations whenever possible. In cases where facilities failed to provide source-specific cost estimates or NMED found estimates provided by facilities to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including -four-factor analyses developed for similar facilities in New Mexico and other states, to estimate costs.

Id. There are substantial flaws in NMED's consideration of costs that necessitate reevaluation of and modifications to the Draft SIP's proposed control requirements for the Enterprise facilities.

A. NMED Has Not Considered Relevant Cost Metrics.

NMED has only considered cost-effectiveness on a simple dollar-per-ton basis. Such limited consideration does not fully evaluate costs and has resulted in Draft SIP requirements that go beyond what is needed to make reasonable progress. In the body of the Draft SIP, for instance, NMED presents only $/ton cost-effectiveness values for SCR. Draft SIP at 114-118. Appendix C, which contains additional narrative explaining NMED's four-factor analysis confirms that the $/ton metric was the only manner in which NMED considered costs. Draft SIP, App. C, at 68-91.

According to EPA's 2019 Guidance, a cost assessment in furtherance of a reasonable progress assessment "will typically produce estimated values of capital costs, annual operating and maintenance costs, annualized costs, and cost per ton of emission reductions, as well as

multiple values for daily visibility benefits." 2019 Guidance at 38. NMED has calculated annualized costs, but does not appear to have considered them. NMED has not considered a $-per-deciview or dollar-per-inverse megameter metric at all. These factors have been determinative in the regional haze proceedings of other states.

- Approval, Disapproval and Promulgation of Implementation Plans; State of Nebraska; Regional Haze State Implementation Plan; Federal Implementation Plan for Best Available Retrofit Technology Determination, 77 Fed. Reg. 40,150, 40,151, 40,156 (July 6, 2012) (EPA partially disapproving Nebraska's SIP after recalculating Nebraska's cost effectiveness analysis for BART using $/dv. Additionally, EPA defended its use of $/dv in response to a comment: "We believe that dollars per deciview is one of several metrics that can be used to analyze cost of visibility improvement, and reaffirm our position that the calculation is more meaningful if cumulative visibility benefits are accounted for.")

- Environmental Protection Agency: Rules and Regulations: Approval and Promulgation of Implementation Plans; State of Oregon; Regional Haze State Implementation Plan and Interstate Transport Plan, 76 Fed. Reg. 38997, 38999 (July 5, 2011) (EPA approving and promulgating Ohio's Regional Haze SIP for the first implementation period based on a dollars/dv threshold of $10 million per deciview; the EPA responded to a comment challenging the threshold by stating that the threshold was "consistent with EPA's review of dollars/dv cost effectiveness data…").

NMED's failure to consider cost metrics in addition to its dollar-per-ton calculations has left NMED with an incomplete picture of the costs of the controls it has proposed. New Mexico must further evaluate all potentially informative cost metrics to ensure that the state has met its obligation to weigh the four factors in determining reasonable progress. Failure to consider this information—which Congress intended the states to take into account—is arbitrary and capricious. *See Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43, (1983).

B. NMED's Cost-Estimates Are Unrealistic and Result in Unreasonable Control Determinations for the Enterprise Facilities.

NMED's assessment of the costs of SCR is incomplete, lacks site-specific information, and understates the costs associated with this control option. For each of the Enterprise facilities, the NMED spreadsheet presenting its SCR cost assessment indicates that NMED relied on default values from EPA's Control Cost Manual and its SCR cost calculation tool. Draft SIP, App. D at 455, 460 (Blanco), 536, 540 (Chaco), 622 (South Carlsbad).

Because Enterprise and NMED had previously concluded that SCR was not technically feasible at the Enterprise facilities due to space constraints, Enterprise did not seek vendor quotes or other information prior to release of the Draft SIP. Enterprise maintains that the site-specific

impediments to construction of SCR should be considered sufficiently onerous to render SCR technically infeasible at the Enterprise facility sites.

In the short time provided for public comment on the Draft SIP, Enterprise has not been able to develop the sort of detailed engineering studies that would be needed to fully assess the true costs of installing and operating SCR at the Enterprise facilities. Such information is needed for a true and accurate cost assessment. Accordingly, NMED should pause its efforts to seek approval of the Draft SIP and ensure that an adequate cost assessment, including site-specific information and vendor quotes, if available, is included in the record and comprises the basis for the SIP's requirements. Proceeding on the basis of NMED's more generic cost assessment when better data could have been obtained is arbitrary and capricious. *Conservation Cong. v. Finley*, 774 F.3d 611, 620 (9th Cir. 2014) ("Agencies 'must support their conclusions with accurate and reliable data'"). If Enterprise is able to obtain additional information further characterizing SCR costs, we will provide it to NMED as expeditiously as possible.

In the time provided, Enterprise has obtained two preliminary vendor quotes that demonstrate the values NMED has relied on are unrealistic. It is first important to emphasize that the quotes Enterprise has received significantly understate likely actual costs. Because of limited time, these quotes were developed without taking into account factors that will significantly impact costs:

1) No SCR feasibility or constructability walk-downs were performed to prepare these estimates.
2) Costs assume no relocations of existing infrastructure would be required; however, as explained further below, substantial relocation and additional construction will be required.
3) Costs are not based on detailed engineering studies.
4) The quotes assume sufficient electricity is available and do not include costs associated with upgrading or adding electrical infrastructure.

Even with these limitations, the vendor quotes indicate that NMED's cost estimates are too low.

Facility	Unit No.	Unit Type	NMED's Proposed NOx Control Measure	NMED's Total Capital Investment Estimate	NMED Cost Effectiveness	Enterprise Capital Investment Estimate	Enterprise Cost Effectiveness (Using NMED Methodology)
	35	Solar Mars T-15000	SCR (90% Reduction)	$5.3 MM	$9,000/ton	$6.8 MM	$10,107/ton
	36	Solar Mars T-15000	SCR (90% Reduction)	$5.3 MM	$9,000/ton	$6.8 MM	$10,713/ton
	37	Solar Mars T-15000	SCR (90% Reduction)	$5.3 MM	$10,000/ton	$6.8 MM	$12,062/ton

South Carlsbad Compressor Station	1	Solar Centaur T-4700	SCR (90% Reduction)	$2.5 MM	$5,000/ton	$7.2 MM	$13,617/ton
	2	Solar Centaur T-4700	SCR (90% Reduction)	$2.5 MM	$5,000/ton	$7.2 MM	$13,670/ton

Thus, even using marginally more accurate cost information substantially affects the outcome of a cost-effectiveness analysis. Without accounting for the complications and additional costs needed to address relocation of existing infrastructure and adequate power supplies, preliminary vendor information provided to Enterprise indicates that NMED has generally underestimated costs, in some cases substantially. Indeed, Enterprise's more accurate cost information establishes clearly that three of the units at Chaco and both units at South Carlsbad would exceed NMED's threshold for cost-effectiveness, even based on incomplete cost data. Enterprise is working to develop additional, more complete cost data for al of the Enterprise facilities and will seek to supplement the record as appropriate.

At least two additional factors excluded from NMED's and Enterprise's cost information will further increase costs significantly: (1) the costs associated with site-specific retrofit complications; (2) the use of an unsupported 90% NOx removal efficiency assumption.

First, costs associated with retrofitting the Enterprise facilities, including moving existing structures and equipment, will considerably affect cost-effectiveness. NMED explains that it attempted to account for the additional costs associated with retrofit complexity at the Enterprise facility sites by using a retrofit factor in EPA's cost calculation tool:

> A retrofit factor of 1.1 was used in the EPA SCR Tool to account for the additional capital costs anticipated to create physical space for the SCR system. This factor was selected based on Enterprise's recurring assertion that the current layout of the existing building cannot accommodate the physical space needed for SCR. Aerial photos provided by Enterprise suggest there is space for SCR if building modifications are made[.]

Draft SIP, App. D at 455. There is no explanation in the Draft SIP, however, as to how this factor affected costs or why it was the appropriate value to select. According to NMED documentation, EPA's SCR cost tool suggests a range of retrofit factors of "between 0.8 and 1.5 based on the level of difficulty" with a value of 1 being "for projects of average retrofit difficulty." *See id*. at 463. At the very least, to provide adequate support for its Draft SIP, NMED must explain why it has selected its chosen retrofit factor and why its choice is reasonable. A full analysis is likely to find that this figure does not fully capture the costs likely to be incurred to install and operate SCR.

Second, both the NMED and Enterprise cost effectiveness values are also overinflated due to the assumption by NMED, which Enterprise replicated in its assessment of the vendor information, that SCR can achieve a 90 percent removal efficiency at the Enterprise facilities.

The basis for that assumption appears to be that 90 percent is a default value in EPA's SCR cost tool. Draft SIP, App. D at 460. The Draft SIP provides no other explanation than the value is an assumption: "Emissions limitations for selective catalytic reduction are based on current actual emissions and an assumed 90% control efficiency." Draft SIP at 140.

This assumption may be appropriate for some industries under certain conditions, but it is not likely applicable to the Enterprise facilities. As explained in the attached letter from Solar Turbines to Enterprise, a much lower removal efficiency is more likely to apply to at least some the Enterprise units. A 60% to 80% NOx reduction may be a more realistic range of NOx reduction achievable with SCRs placed on certain Enterprise units.[22]

The reduction efficiencies Solar Turbines supports are consistent with EPA's analysis. In its AP-42: Compilation of Air Emissions Factors from Stationary Sources, EPA explains that "[t]he removal efficiency of an SCR system in good working order is typically from 65 to 90 percent." AP-42 at § 3.1.4.3. NMED should, at the least, assume a more realistic removal efficiency. NMED should further conduct a full assessment of removal-efficiency achievability for the Enterprise facilities. Such a change will further increase the cost-effectiveness values.

Enterprise believes that the best available information indicates that SCR is not cost-effective. Just as importantly, however, NMED has not made an adequate demonstration that SCR is cost-effective. Because that burden falls upon the state, NMED should withdraw its Draft SIP, conduct a more fulsome cost analysis, consistent with these comments, and propose a substantially revised Draft SIP.

C. NMED's Cost-Estimates Threshold is Too High.

NMED has adopted a "cost effectiveness threshold value (CETV) to remove control measures deemed not cost-effective from further consideration." Draft SIP at 102. NMED set its CETV at $10,000/ton NOx removed. *Id*. This threshold is too high and an outlier among states.

- Partial Approval and Disapproval of Air Quality Implementation Plans; Arizona; Regional Haze State Implementation Plan for the Second Implementation Period and Prong 4 (Visibility) for the 2015 Ozone and 2012 Particulate Matter Standards, 89 Fed. Reg. 47,398, 47,429 (May 31, 2024) (Cost-effectiveness threshold of $6,500/ton for point sources).
- Disapproval and Promulgation of Air Quality Implementation Plans; Texas and Oklahoma; Regional Haze State Implementation Plans; Federal Implementation Plan for Regional Haze; Completion of Remand, 88 Fed. Reg. 48,152, 48,167 (July 26, 2023) (cost-effectiveness threshold of $2,700/ton).

[22] Letter from Solar Turbines, Re: Solar Compressor Sets - NOx Reductions per NM Regional Haze Rule Requirements (Sept. 9, 2024) (Attachment C).

- Approval, Disapproval and Promulgation of Implementation Plans; State of Nebraska; Regional Haze State Implementation Plan; Federal Implementation Plan for Best Available Retrofit Technology Determination, 77 Fed. Reg. 40,150, 40,159 (July 6, 2012) (cost effectiveness threshold of $5,000 incremental cost per ton).

In addition to relying on much lower cost-effectiveness thresholds, several of these states failed, in EPA's view, to adequately support their chosen cost-effectiveness thresholds. *See, e.g.*, *id*. NMED has likewise failed to explain why its threshold is reasonable.

In one recent rulemaking action addressing the regional haze SIP for Missouri, EPA reviewed cost-effectiveness thresholds used in the regional haze context. In that action, EPA notes that Missouri selected cost-effectiveness thresholds of $3,658 per ton for SO_2 controls and $5,370 per ton for NOx controls. Air Plan Partial Approval and Partial Disapproval; Missouri; Regional Haze, 89 FR 55140, 55154 (July 3, 2024). Although EPA proposed to find those values were too low, EPA instead found costs in the range of $5,000/ton to $6,000/ton for SO_2 control would be more appropriate. *Id*.

EPA further explained that the regional planning organization for Missouri had recommended cost-effectiveness thresholds in a range from $4,000 to $5,000/ton (in 2005 dollars) which becomes $6,060 to $7,600/ton in 2021 dollars. *Id*. EPA provided another example with its own cost-effectiveness threshold of $4,200 to $5,100/ton range (escalated to 2020 dollars) for a Texas regional haze federal implementation plan. EPA further noted that, in 2021 dollars, this range is $5,300/ton to $6,500/ton. *Id*.

The one thing all of these values have in common is that they are much lower than NMED's cost-effectiveness threshold. If NMED were to adopt a threshold more in line with the practice of other states and EPA itself, it is likely that none of the Enterprise facilities would be deemed to have additional cost-effective control options, and SCR would certainly not be deemed cost-effective.

D. NMED Should Provide Enterprise an Opportunity to Address Specific Cost Items.

In the Draft SIP, NMED says that it excluded certain cost items provided by Enterprise or relied on default values where information was not available:

> In cases where Enterprise failed to provide source-specific cost estimates or NMED found estimates provided by Enterprise to be unreliable, NMED utilized EPA's Control Cost Manual or other reliable sources of information, including FFAs developed for similar facilities in New Mexico and other states, to estimate costs.

Draft SIP, App. C at 69. Enterprise believes the information it has provided is reliable, and requests that NMED identify gaps in information that it deems crucial or that might otherwise address any shortcomings NMED perceives with the information Enterprise has provided. Enterprise will work with the Department to provide the more reliable possible information.

XI. In the Alternative, NMED Should Provide Enterprise With Additional Compliance Flexibility.

As drafted, NMED's proposed regulation would impose unit-by-unit emission rate limits for each of the Enterprise facilities. NMED can achieve the same emission reductions and the same improvements in visibility (minimal as they may be) while providing for greater operational flexibility for the Enterprise facilities.

Specifically, if NMED proceeds to seek final approval of its Draft SIP without changing course on requiring emission limits based on SCR for the Enterprise facilities—which it should not—Enterprise requests that NMED allow for facility-wide averaging. Allowing this additional compliance flexibility will ensure that each facility meets an overall emission rate limit while allowing Enterprise to operate the respective emissions units at each facility in the most efficient manner possible.

Allowing for averaging in this manner is fully consistent with the state's legal authority under the regional haze program and similar approaches have been adopted to address reasonable progress requirements in the past.

- Approval and Promulgation of Air Quality Implementation Plans; New Hampshire; Regional Haze, 77 Fed. Reg. 11,809 11,818 (Feb. 28, 2012) (placing two unit within a regulatory "bubble" for compliance purposes).

- Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans, 77 Fed. Reg. 72,512, 72,527 (Dec. 5, 2012) (applying a compliance "bubble" across multiple units)

Enterprise further requests that NMED reevaluate the emission rate limits contained in the Companion Rule. Those limits are likely too stringent even with installation of SCR, although Enterprise will continue to evaluate this issue. Emission rate limits in the SIP should instead be based on the existing controls at the Enterprise facilities.

CONCLUSION

For all of the foregoing reasons, NMED's Draft SIP would impose unwarranted emission control requirements on Enterprise's facilities. The Draft SIP's requirements are based on a flawed cost assessment and a failure of the Department to fully consider the four reasonable progress factors and the visibility implications of its proposed emission control requirements. NMED should withdraw the Draft SIP and propose regional haze requirements for the Enterprise facilities consistent with the site-specific analysis Enterprise has provided and the CAA's goal that states make reasonable progress toward the national visibility goal.

Should you have any questions regarding this submittal, please contact Tucker Jacobson at (713) 381-4313 (wtjacobson@eprod.com) or Bradley Cooley at (713) 381-5828 (bjcooley@eprod.com).

Sincerely,



Aaron M. Flynn
Counsel for Enterprise Field Services

Attachment A

ENTERPRISE PRODUCTS PARTNERS L.P.

REGIONAL HAZE PLANNING MEETING

February 19, 2020

EPD
LISTED
NYSE

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AGENDA

- NMED Regional Haze Planning Status and Process
- Questions on Four-Factor Analysis Reports
  - South Carlsbad Compressor Station
  - Blanco C & D Compressor Station
  - Chaco Gas Plant
- Impact to Regional Haze

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2016 REGIONAL HAZE RULE IMPACTED FACILITIES

Attachment 2. Title V sources required to conduct a four-factor analysis of control measures under the 2016 Regional Haze Rule.

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

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SOUTH CARLSBAD COMPRESSOR STATION



South Carlsbad Compressor Station

- 16.2 miles from Carlsbad Caverns National Park

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BLANCO C & D COMPRESSOR STATION
CHACO GAS PLANT



Blanco C & D Compressor Station

- 39.5 miles to Mesa Verde National Park

Chaco Gas Plant

- 49.5 miles to Mesa Verde National Park

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EPA MODELING – CARLSBAD CAVERNS

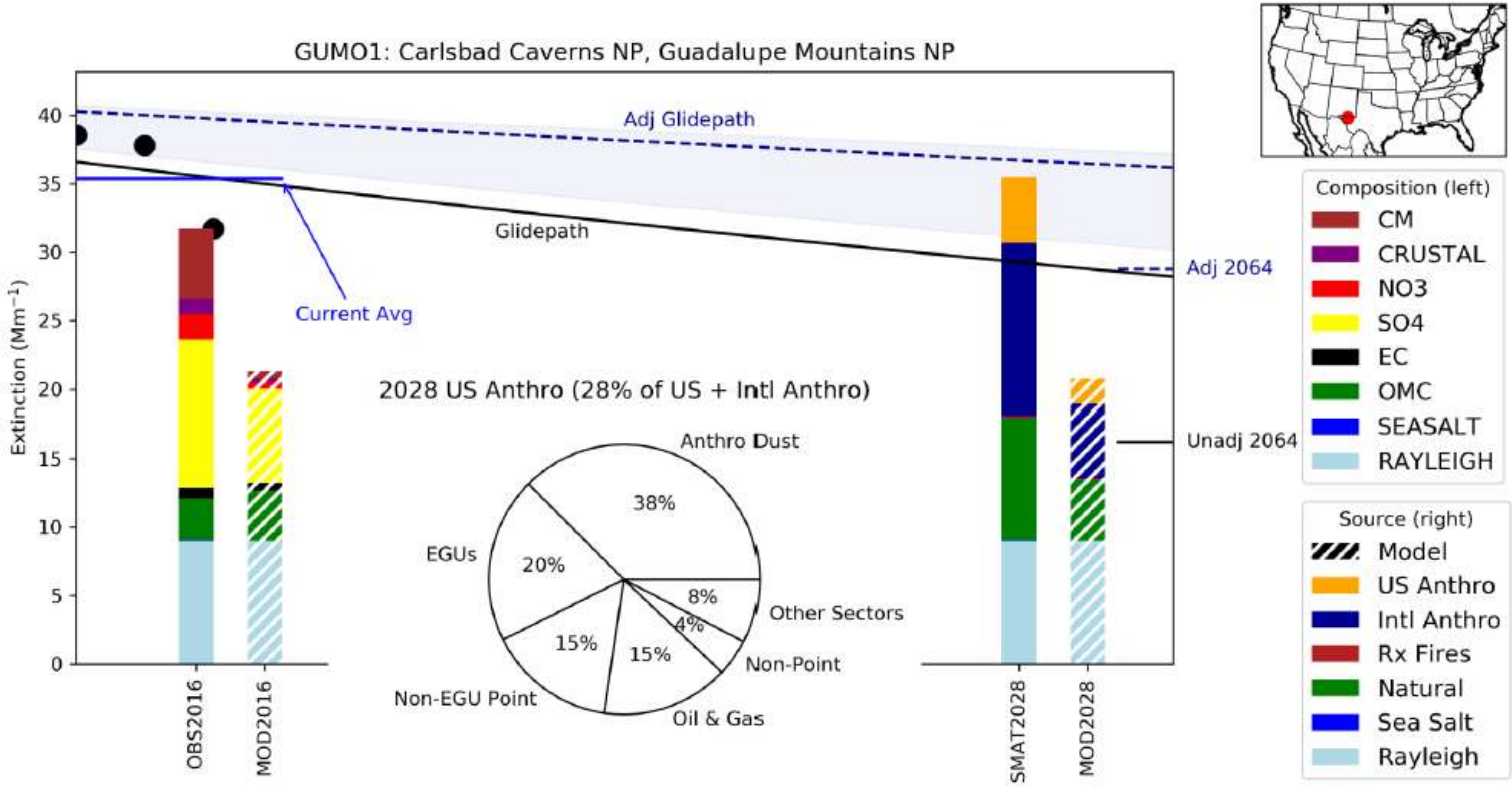


Figure 34: 2014-2017 IMPROVE observations, 2016 CAMx model predictions, 2028 modeled projection, and 2028 sector contributions at GUMO1. Used for Class I areas: Carlsbad Caverns NP, Guadalupe Mountains NP.

Class I Area	2028 Projected 20% most impaired days (dv)	2028 Unadjusted Glidepath 20% most impaired days (dv)	2028 Default Adjusted Glidepath (dv)	2028 Minimum Alternative Adjusted Glidepath (dv)	2028 Maximum Alternative Adjusted Glidepath (dv)
Carlsbad	**12.48**	**10.69**	**12.99**	**11.32**	**13.25**

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EPA MODELING – MESA VERDE

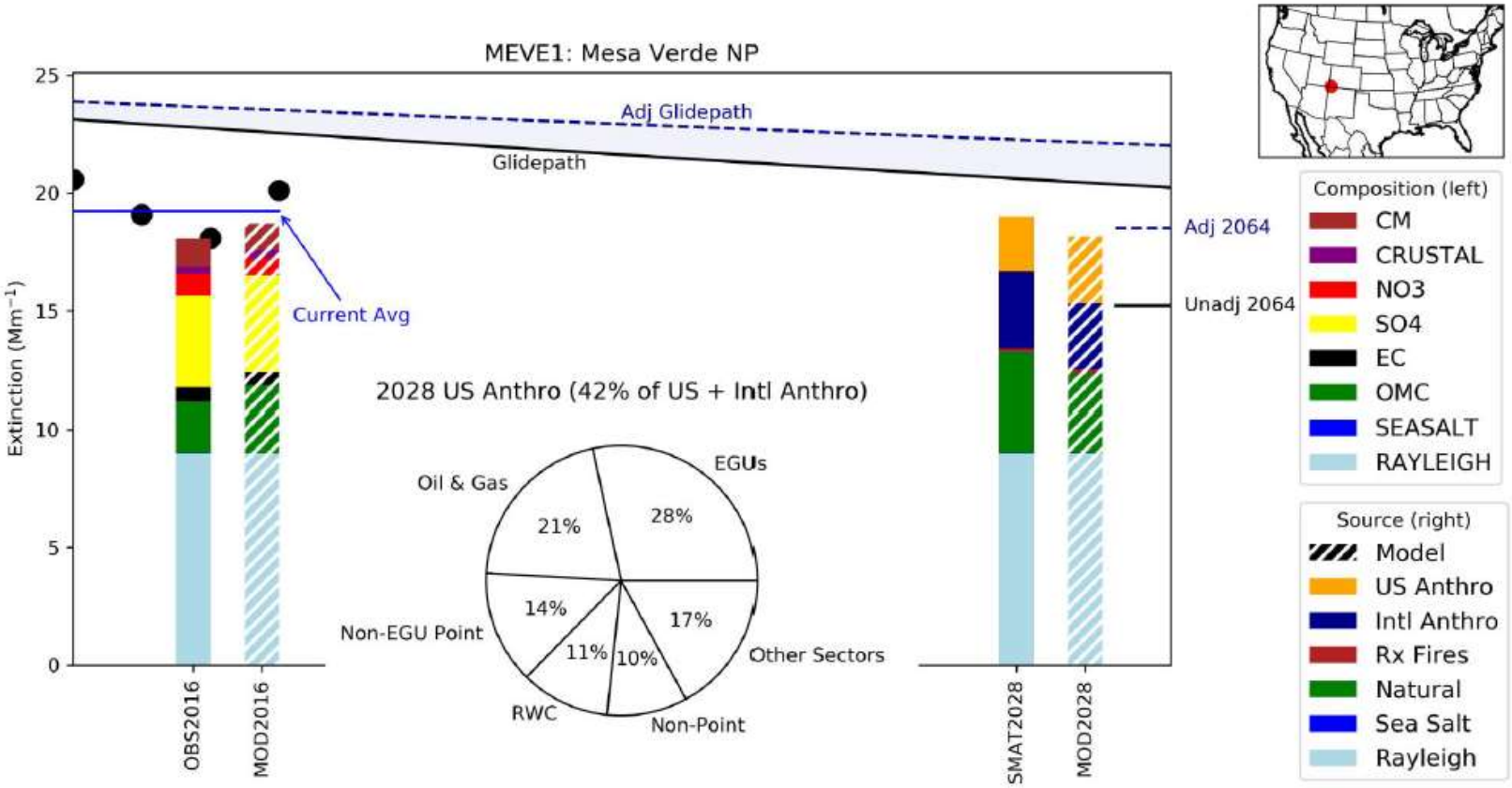


Figure 52: 2014-2017 IMPROVE observations, 2016 CAMx model predictions, 2028 modeled projection, and 2028 sector contributions at MEVE1. Used for Class I areas: Mesa Verde NP.

Class I Area	2028 Projected 20% most impaired days (dv)	2028 Unadjusted Glidepath 20% most impaired days (dv)	2028 Default Adjusted Glidepath (dv)	2028 Minimum Alternative Adjusted Glidepath (dv)	2028 Maximum Alternative Adjusted Glidepath (dv)
Mesa Verde	**6.3**	**7.22**	**8.00**	**7.24**	**8.03**

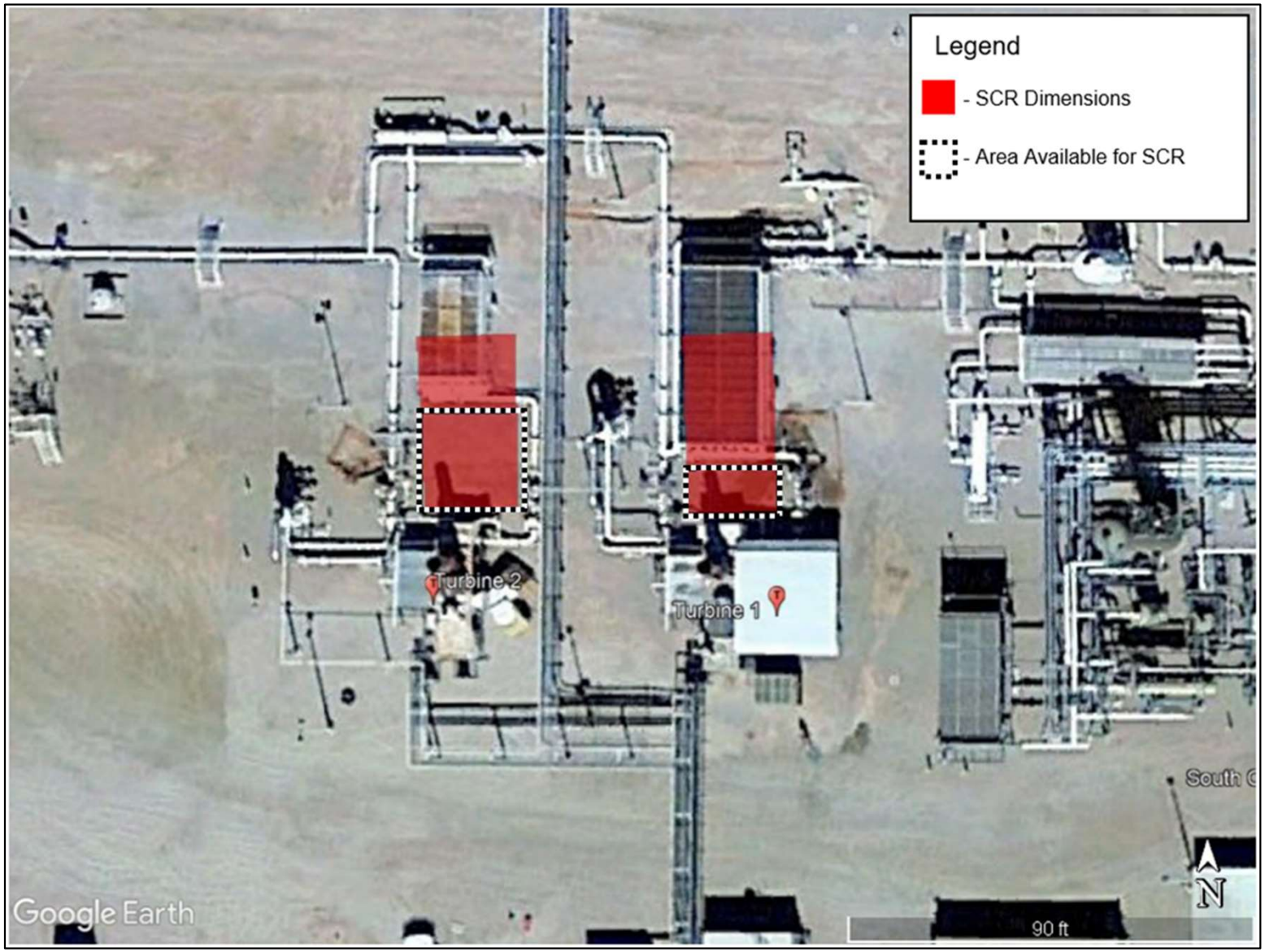
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COST EFFECTIVENESS SUMMARY

Facility	Combustion Source	Unit No.	2016 NOx Emissions (tpy)	NOx Reduction Technology	2016 NOx Emissions w/ Control (tpy)	Cost Effectiveness ($/ton removed)
South Carlsbad Compressor Station	Solar Centaur T4702	1	32.42	SoloNOx (25 ppm)	11.64	$ 8,583.57
	Solar Centaur T4702	2	40.8	SoloNOx (25 ppm)	13.89	$ 6,629.15
Blanco C & D Compressor Station	GE Frame 5	T-C01	158.6	Water Injection (15% Reduction)	134.81	$ 79,086.07
				Steam Injection (15% Reduction)		$ 110,101.19
				Water Injection (42 ppm)	115.44	$ 43,598.09
				Steam Injection (42 ppm)		$ 60,695.91
	GE Frame 5	T-C02	219.26	Water Injection (15% Reduction)	186.37	$ 57,206.25
				Steam Injection (15% Reduction)		$ 79,640.77
				Water Injection (42 ppm)	110.68	$ 17,328.49
				Steam Injection (42 ppm)		$ 24,124.20
	GE M5322B	T-D01	197.37	Dry Low NOx (DLN) (35 ppm)	106.33	$ 9,934.37
				Water Injection (15% Reduction)	167.76	$ 63,551.77
				Steam Injection (15% Reduction)		$ 88,474.82
				Water Injection (42 ppm)	127.59	$ 26,965.69
				Steam Injection (42 ppm)		$ 37,540.80
Chaco Gas Plant	Clark TLA-10	12	107.7	NOx reduction controls not evaluated based on technical infeasibility		
	Clark TLA-10	13	197.3			
	Clark TLA-10	14	189.2			
	GE Frame 5	17	126.82	Water Injection (15% Reduction)	107.80	$ 106,606.41
				Steam Injection (15% Reduction)		$ 148,511.84
	GE Frame 5	18	126.61	Water Injection (15% Reduction)	107.62	$ 106,784.35
				Steam Injection (15% Reduction)		$ 148,759.74
	Solar Mars T-15000	35	119.52	SoloNOx (15 ppm)	14.34	$ 6,800.13
	Solar Mars T-15000	36	117.84	SoloNOx (15 ppm)	14.52	$ 6,668.02
	Solar Mars T-15000	37	85.97	SoloNOx (15 ppm)	12.48	$ 9,434.46

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SOUTH CARLSBAD COMPRESSOR STATION

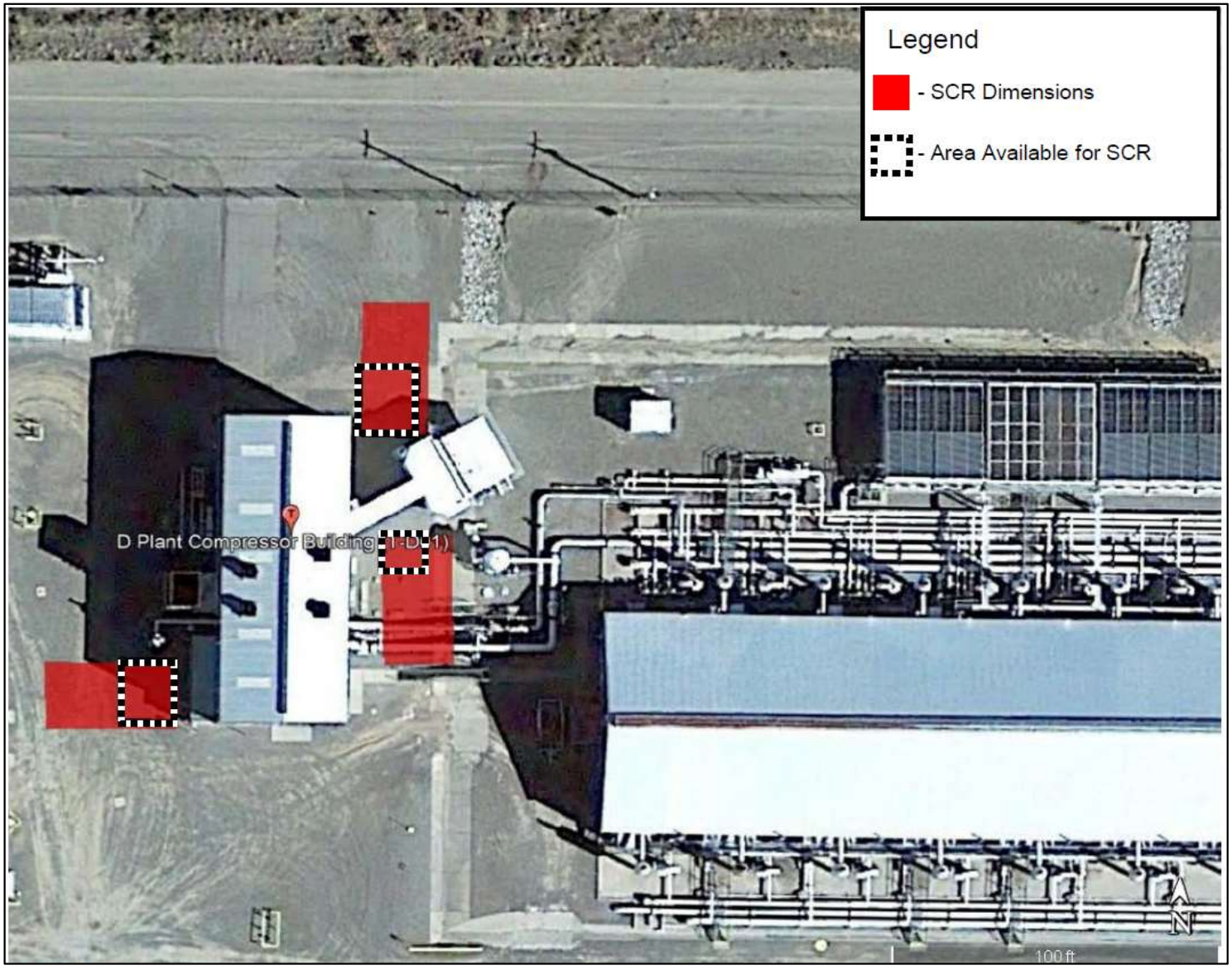


Solar Centaur T4702 Turbines (1 and 2)

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BLANCO C & D COMPRESSOR STATION

(D PLANT)

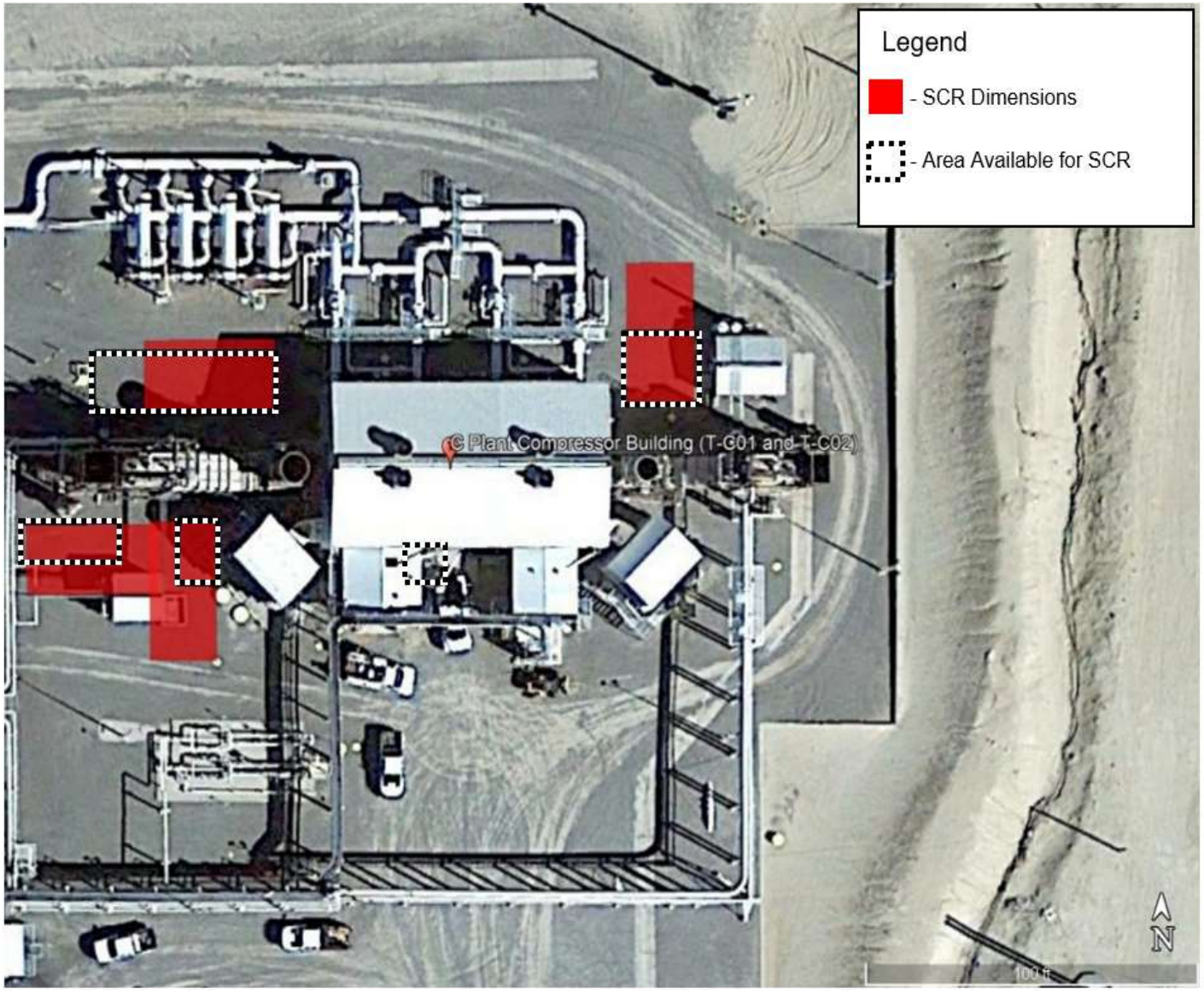


GE M5322B Turbine (T-D01)

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BLANCO C & D COMPRESSOR STATION

(C PLANT)



GE Frame 5 Turbines (T-C01 and T-C02)

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CHACO GAS PLANT



Clark TLA-10 Engines (12,13,14), GE Frame 5 Turbines (17,18), Solar Mars T-15000 Turbines (35,36,37)

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Attachment B

From:	Olson, Kirby, ENV
To:	Jacobson, Tucker
Cc:	Cooley, Bradley; Craft, Zachary; PKULKARNIE@eprod.com; Jones, Mark, ENV; Miller, Kenneth, ENV; Sanchez, Alex, ENV
Subject:	[EXTERNAL] Revised Regional haze cost evaluations for Blanco C&D and Chaco Gas Plant
Date:	Wednesday, December 20, 2023 10:54:16 AM
Attachments:	2023-12-19_Corrected Draft Final NMED Cost Evaluation_Enterprise - Blanco C and D Compressor Station.xlsx 2023-12-19_Corrected Draft Final NMED Cost Evaluation_Enterprise - Chaco Gas Plant.xlsx

[Use caution with links/attachments]

Dear Mr. Jacobson,

After sending you NMED's draft final cost evaluations for Enterprise Field Services, LLC's Blanco C&D Compressor Station, Chaco Gas Plant and South Carlsbad Compressor Station last Thursday (12/14), our Regional Haze planning team discovered a formula error in the following sheets:

- Sheet "Eval – EMD" of the Blanco C&D Compressor Station workbook, resulting in an incorrect 2023$ cost effectiveness value for Unit T-C02
- Sheet "EMD1" of the Chaco Gas Plant workbook, resulting in an incorrect 2023$ cost effectiveness value for Unit 18
- Sheet "EMD2" of the Chaco Gas Plant workbook, resulting in incorrect 2023$ cost effectiveness values for Units 36 and 37
- Sheet "EMD3" of the Chaco Gas Plant workbook, resulting in incorrect 2023$ cost effectiveness values for Units 13 and 14

The errors have been corrected in the attached workbooks. Please disregard the Blanco C&D Compressor Station and Chaco Gas Plant workbooks we provided last week and review the sheets in the attached, corrected versions instead. As a reminder, the deadline to submit review comments is Jan. 15, 2024.

Regards,
Kirby Olson

This email is intended to serve as general guidance and is in no way a formal statement of Department policy. Unique operating conditions may result in different determinations and may require a site specific analysis to accurately determine requirements and applicability.

Kirby Sue Olson, Ph.D.
Planning Section Chief
Air Quality Bureau
New Mexico Environment Department
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505
Phone: (505) 629-5107
Fax: (505) 476-4375

kirby.olson@env.nm.gov
https://www.env.nm.gov

"Science, Innovation, Collaboration, Compliance"

Facility Information

Enterprise - Blanco C & D	**Facility**
Two pre-June 1989 CTs, 22,280 HP each	**Units**
T-C01 and T-C02	**Unit IDs**
Water/Steam Injection	**Evaluated Pollution Control**
42.0	**Post-control Emissions Rate (ppmv**

Supporting Information

1999	Calendar year associated with cost e
22,280	Nameplate Capacity (hp/unit)

Economic Evaluation

Cost Component		**T-C01**
Purchased equipment costs ($)	PEC	$ 431,000
Other Direct Capital Costs 1 ($)	ODC	$ 243,975
Indirect Capital Costs ($)	IDC	$ 408,200
Total Capital Costs - Direct ($)	TCC	$ 1,083,175
Additional Capital ($)	AC	$ -
Total Capital Investment ($)	TCI	$ 1,083,175
Interest Rate (%)	R	10.50%
Useful Life (yr)	Y	15
Capital Recovery Factor	CRF	0.1352
Annualized Capital Costs ($/yr)	ACC	$ 146,497
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 294,000
Other Indirect Annual Costs ($/yr)	OAC	$ 43,327
Total Annualized Costs ($/yr)	TAC	$ 483,824
NOx Control Efficiency (%)	Eff	9%
Baseline Actual NOx Emissions (ton/yr)	BAE	139.7
Future Utilization Adjustment (%)	FUA	0%

Projected Actual Emissions (ton/yr)	PAE	139.7
Estimated Reductions (ton/yr)	ER	12.0
1999$ Cost Effectiveness ($/ton)	**CE1**	**$ 40,399**
Consumer Price Index Ratio	CPI	$ 1.83
2023$ Cost Effectiveness ($/ton)	**CE2**	**$ 73,962**

(A) Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, Nov 1999, Table A-4, 25
Note: Units T-C01 and T-C02 are ~ 16.6 MW (mechanical) units and thus reasonably similiar in size

d)

estimates (based on primary data source)

T-C02	Source
$ 431,000	(A)
$ 243,975	(A)
$ 408,200	(A)
$ 1,083,175	-
$ -	Not specified by Enterprise
$ 1,083,175	(A)
10.50%	Enterprise August 2023 FFA update
15	Enterprise initial (2019) FFA and August 2023 update
0.1352	-
$ 146,497	-
$ 294,000	(A)
$ 43,327	EPA Cost Manual, Section 2.6.5.8
$ 483,824	-
34%	-
195.1	CY 2018 emissions testing and average operating hours (2016-2
0%	Not specified by Enterprise

195.1	-
65.5	-
$ 7,384	-
$ 1.83	https://www.bls.gov/data/inflation_calculator.htm
$ 13,518	-

MW Class

to the 25 MW Class used in the analysis.

Methodology/Note
Total system cost
Taxes Freight and installation direct costs
Indirect installation and contingency
PEC + ODC + IDC
TCC + AC
Standard CRF calculation
TCI x CRF
Annual costs (does not include Capital Recovery)
4% of TCI
ACC + OMC + OAC
(Current actual - Post Control)/Current actual
021)

BAE x (1 + FUA)
PAE x Eff
TAC/ER

Based on CPI for All Urban Consumers: Refer to table in CPI Worksheet

CE1x CPI

Facility Information

Enterprise - Blanco C & D	**Facility**
Two pre-June 1989 CTs, 22,280 HP each	**Units**
T-C01 and T-C02	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
9.0	**Post-control Emissions Rate (ppmv**

Supporting Information

2020	Calendar year associated with cost e
22,280	Nameplate Capacity (hp/unit)

Economic Evaluation

Cost Component		**T-C01**
Purchased equipment costs ($)	PEC	$ -
Other Direct Capital Costs 1 ($)	ODC1	$ -
Other Direct Capital Costs 2 ($)	ODC2	$ -
Indirect Capital Costs ($)	IDC	$ -
Total Capital Costs - Direct ($)	TCC	$ -
Additional Capital ($)	AC	$ -
Total Capital Investment ($)	TCI	$ 53,873,040
Interest Rate (%)	R	10.50%
Useful Life (yr)	Y	30
Capital Recovery Factor	CRF	0.1105
Annualized Capital Costs ($/yr)	ACC	$ 5,954,505
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 46,465
Other Indirect Annual Costs ($/yr)	OAC	$ -
Total Annualized Costs ($/yr)	TAC	$ 6,000,971
NOx Control Efficiency (%)	Eff	80%
Baseline Actual NOx Emissions (ton/yr)	BAE	139.7

Future Utilization Adjustment (%)	FUA	0%
Projected Actual Emissions (ton/yr)	PAE	139.7
Estimated Reductions (ton/yr)	ER	112.4
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 53,405**
Consumer Price Index Ratio	CPI	$ 1.18
2023$ Cost Effectiveness ($/ton)	**CE2**	**$ 63,018**

d)

estimates (year not specified in submission)

T-C02	Source
$ -	Included in TCI
$ -	Included in TCI
$ -	Included in TCI
$ -	Included in TCI
$ -	Included in TCI
$ -	Included in TCI
$ 53,873,040	9/8/20 info from El Paso Natural Gas
10.50%	Enterprise August 2023 FFA update
30	ERG experience based on discussions with CT manufacturers
0.1105	-
$ 5,954,505	-
$ 46,465	Enterprise August 2023 FFA update (2023$ converted to 2020$
$ -	-
$ 6,000,971	-
86%	-
195.1	CY 2018 emissions testing and average operating hours (2016-2

0%	Not specified by Enterprise
195.1	-
167.3	-
$ 35,868	Cost info provided by EPNG on 9/8/20 so assumed costs are in
$ 1.18	https://www.bls.gov/data/inflation_calculator.htm
$ 42,324	-

Methodology/Note
All-in estimate ($/HP) x Maximum Power Output (HP)
Standard CRF calculation
TCI x CRF
Incremental overhaul costs for DLN retrofit
4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs a
ACC + OMC + OAC
(Current actual - Post Control)/Current actual
021)

BAE x (1 + FUA)
PAE x Eff
TAC/ER

Based on CPI for All Urban Consumers (July 2020 -> July 2023)

CE1 x CPI

ssociated with replacement with an equivalent/like-kind unit

Facility Information

Enterprise - Blanco C & D	**Facility**
Two pre-June 1989 CTs, 22,280 HP each	**Units**
T-C01 and T-C02	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (lb/hr)**

Additional Information

2023	Calendar year associated with cost e
22,280	Nameplate Capacity (hp/unit)

Economic Evaluation

Cost Component		**T-C01**
Purchased equipment costs ($)	PEC	$ -
Other Direct Capital Costs 1 ($)	ODC1	$ -
Other Direct Capital Costs 2 ($)	ODC2	$ -
Indirect Capital Costs ($)	IDC	$ -
Total Capital Costs - Direct ($)	TCC	$ 46,431,520
Additional Capital ($)	AC	$ -
Total Capital Investment ($)	TCI	$ 46,431,520
Interest Rate (%)	R	10.50%
Useful Life (yr)	Y	25
Capital Recovery Factor	CRF	0.114
Annualized Capital Costs ($/yr)	ACC	$ 5,313,127
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 4,485,294
Additional Electricity Demand ($/yr)	AED	$ 8,970,588
Associated non-electricity O&M ($/yr)	AOM	$ -
Annual Fuel Credit ($/yr)	AFC	$ (4,485,294)
Other Indirect Annual Costs ($/yr)	OAC	$ -
Total Annualized Costs ($/yr)	TAC	$ 9,798,421
NOx Control Efficiency (%)	Eff	100%

Baseline Actual NOx Emissions (ton/yr)	BAE	139.7
Future Utilization Adjustment (%)	FUA	0%
Projected Actual Emissions (ton/yr)	PAE	139.7
Estimated Reductions (ton/yr)	ER	139.7
2023$ Cost Effectiveness ($/ton)	**CE**	**$ 70,115**

estimates

T-C02	Source
$ -	Included in TCC
$ -	Included in TCC
$ -	Included in TCC
$ -	Included in TCC
$ 46,431,520	-
$ -	-
$ 46,431,520	-
10.50%	Enterprise Aug 2023 CBI update
25	Consistent with other FFAs
0.114	-
$ 5,313,127	-
$ 4,538,198	
$ 9,076,396	ERG calculation
$ -	Engineering judgement
$ (4,538,198)	ERG calculation
$ -	-
$ 9,851,325	-
100%	-

195.1	CY 2018 emissions testing and average operating hours (2016-2
0%	Not specified by Enterprise
195.1	-
195.1	-
$ 50,502	**-**

Methodology/Note
Enterprise provided a cost estimate for electrification using EPA Cost Control Manual Section 5.2, which pertains to acid gas scrubbers. As this is not applicable to replacement with EMD, a Total Capital Cost metric of $2,084 (2023$/hp) was calculated using detailed cost information provided by other facilities. The TCI figure assumes no costs associated with substation or distribution line upgrades. This assumption underestimates costs given that Enterprise indicated in its August 2023 update that utility infrastructure upgrades would be needed to support electrification at all three of its facilities.
TCC + AC
Standard CRF calculation
TCI x CRF
AED + AOM + AFC
Assumes units at 60% load, 95% efficiency and a $0.10/kWh price
Assumed to be negligible
Assumed equal to 50% of AED
4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs a
ACC + OMC + OAC
No emissions from EMD units

021)
BAE x (1 + FUA)
PAE x Eff
TAC/ER

ssociated with replacement with an equivalent/like-kind unit

Facility Information

Enterprise - Blanco C & D	**Facility**
Pre 1978 GE M5322B NG CT, 32,550 HP	**Units**
T-D01	**Unit IDs**
DLN	**Evaluated Pollution Control**
35.0	**Post-control Emissions Rate (ppmv**

Supporting Information

2023	Calendar year associated with cost e
32,550	Nameplate Capacity (hp/unit)

Economic Evaluation

Cost Component		**T-D01**
Purchased equipment costs ($)	PEC	$ -
Other Direct Capital Costs 1 ($)	ODC	$ -
Indirect Capital Costs ($)	IDC	$ -
Total Capital Costs - Direct ($)	TCC	$ -
Additional Capital ($)	AC	$ -
Total Capital Investment ($)	TCI	$ 9,114,000
Interest Rate (%)	R	10.50%
Useful Life (yr)	Y	20
Capital Recovery Factor	CRF	0.1215
Annualized Capital Costs ($/yr)	ACC	$ 1,107,290
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 54,829
Other Indirect Annual Costs ($/yr)	OAC	$ 364,560
Total Annualized Costs ($/yr)	TAC	$ 1,526,679
NOx Control Efficiency (%)	Eff	34%
Baseline Actual NOx Emissions (ton/yr)	BAE	131.6
Future Utilization Adjustment (%)	FUA	0%

Projected Actual Emissions (ton/yr)	PAE	131.6
Estimated Reductions (ton/yr)	ER	44.7
2023$ Cost Effectiveness ($/ton)	**CE**	**$ 34,129**

d)

estimates (year not specified in submission)

Source
Included in TCI
Included in TCI
Included in TCI
Included in TCI
Included in TCI
Enterprise August 2023 FFA Update
Enterprise August 2023 FFA Update
Enterprise initial (2019) FFA and August 2023 update
-
-
Enterprise August 2023 FFA Update
EPA Cost Manual, Section 2.6.5.8
-
-
CY 2018 emissions testing and average operating hours (2016-2
Not specified by Enterprise

-
-
-

Methodology/Note
All-in estimate ($/HP) x Maximum Power Output (HP)
Consistent with other FFAs
Standard CRF calculation
TCI x CRF
"Incremental overhaul costs"
4% of TCI
ACC + OMC + OAC
(Current actual - Post Control)/Current actual
021)

BAE x (1 + FUA)
PAE x Eff
TAC/ER

Facility Information

Enterprise - Blanco C & D	**Facility**
Pre 1978 GE M5322B NG CT, 32,550 HP	**Units**
T-D01	**Unit IDs**
Water/Steam Injection	**Evaluated Pollution Control**
42.0	**Post-control Emissions Rate (ppmv**

Supporting Information

1999	Calendar year associated with cost e
32,550	Nameplate Capacity (hp/unit)

Economic Evaluation

Cost Component		**T-D01**
Purchased equipment costs ($)	PEC	$ 431,000
Other Direct Capital Costs 1 ($)	ODC	$ 243,975
Indirect Capital Costs ($)	IDC	$ 408,200
Total Capital Costs - Direct ($)	TCC	$ 1,083,175
Additional Capital ($)	AC	$ -
Total Capital Investment ($)	TCI	$ 1,083,175
Interest Rate (%)	R	10.50%
Useful Life (yr)	Y	15
Capital Recovery Factor	CRF	0.1352
Annualized Capital Costs ($/yr)	ACC	$ 146,497
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 294,000
Other Indirect Annual Costs ($/yr)	OAC	$ 43,327
Total Annualized Costs ($/yr)	TAC	$ 483,824
NOx Control Efficiency (%)	Eff	21%
Baseline Actual NOx Emissions (ton/yr)	BAE	131.6
Future Utilization Adjustment (%)	FUA	0%

Projected Actual Emissions (ton/yr)	PAE	131.6
Estimated Reductions (ton/yr)	ER	27.4
1999$ Cost Effectiveness ($/ton)	**CE1**	**$ 17,688**
Consumer Price Index Ratio	CPI	$ 1.83
2023$ Cost Effectiveness ($/ton)	**CE2**	**$ 32,383**

(A) Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, Nov 1999, Table A-4, 25
Note: Unit T-D01 is ~ 24 MW (mechanical) and thus reasonably similiar in size to the 25 MW Class

d)

estimates (based on primary data source)

Source
(A)
(A)
(A)
-
Not specified by Enterprise
(A)
Enterprise August 2023 FFA update
Enterprise initial (2019) FFA and August 2023 update
-
-
(A)
EPA Cost Manual, Section 2.6.5.8
-
-
CY 2018 emissions testing and average operating hours (2016-2
Not specified by Enterprise

-
-
-
https://www.bls.gov/data/inflation_calculator.htm
-

MW Class
used in the analysis.

Methodology/Note
Total system cost
Taxes Freight and installation direct costs
Indirect installation and contingency
PEC + ODC + IDC
TCC + AC
Standard CRF calculation
TCI x CRF
Annual costs (does not include Capital Recovery)
4% of TCI
ACC + OMC + OAC
(Current actual - Post Control)/Current actual
021)

BAE x (1 + FUA)
PAE x Eff
TAC/ER

Based on CPI for All Urban Consumers: Refer to table in CPI Worksheet

CE1x CPI

Facility Information

Enterprise - Blanco C & D	**Facility**
Pre 1978 GE M5322B NG CT, 32,550 HP	**Units**
T-D01	**Unit IDs**
Replacement with new CT	**Evaluated Pollution Control**
9.0	**Post-control Emissions Rate (ppmv**

Supporting Information

2020	Calendar year associated with cost e
32,550	Nameplate Capacity (hp/unit)

Economic Evaluation

Cost Component		**T-D01**
Purchased equipment costs ($)	PEC	$ -
Other Direct Capital Costs 1 ($)	ODC1	$ -
Other Direct Capital Costs 2 ($)	ODC2	$ -
Indirect Capital Costs ($)	IDC	$ -
Total Capital Costs - Direct ($)	TCC	$ -
Additional Capital ($)	AC	$ -
Total Capital Investment ($)	TCI	$ 78,705,900
Interest Rate (%)	R	10.50%
Useful Life (yr)	Y	30
Capital Recovery Factor	CRF	0.1105
Annualized Capital Costs ($/yr)	ACC	$ 8,699,244
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 46,465
Other Indirect Annual Costs ($/yr)	OAC	$ -
Total Annualized Costs ($/yr)	TAC	$ 8,745,709
NOx Control Efficiency (%)	Eff	83%
Baseline Actual NOx Emissions (ton/yr)	BAE	131.6

Future Utilization Adjustment (%)	FUA	0%
Projected Actual Emissions (ton/yr)	PAE	131.6
Estimated Reductions (ton/yr)	ER	109.3
2020$ Cost Effectiveness ($/ton)	**CE1**	**$ 80,025**
Consumer Price Index Ratio	CPI	$ 1.18
2023$ Cost Effectiveness ($/ton)	**CE2**	**$ 94,430**

d)

estimates (year not specified in submission)

Source
Included in TCI
Included in TCI
Included in TCI
Included in TCI
Included in TCI
Included in TCI
9/8/20 info from El Paso Natural Gas
Enterprise August 2023 FFA update
ERG experience based on discussions with CT manufacturers
-
-
Enterprise August 2023 FFA update (2023$ converted to 2020$
-
-
-
CY 2018 emissions testing and average operating hours (2016-2

Not specified by Enterprise
-
-
Cost info provided by EPNG on 9/8/20 so assumed costs are in
https://www.bls.gov/data/inflation_calculator.htm
-

Methodology/Note
All-in estimate ($/HP) x Maximum Power Output (HP)
Standard CRF calculation
TCI x CRF
Incremental overhaul costs for DLN retrofit
4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary costs a
ACC + OMC + OAC
(Current actual - Post Control)/Current actual
021)

BAE x (1 + FUA)
PAE x Eff
TAC/ER

Based on CPI for All Urban Consumers (July 2020 -> July 2023)

CE1 x CPI

ssociated with replacement with an equivalent/like-kind unit

Facility Information

Enterprise - Blanco C & D	**Facility**
Pre 1978 GE M5322B NG CT, 32,550 HP	**Units**
T-D01	**Unit IDs**
Replacement with Electric Motor Drive	**Evaluated Pollution Control**
0.0	**Post-control Emissions Rate (lb/hr)**

Additional Information

2023	Calendar year associated with cost e
32,550	Nameplate Capacity (hp/unit)

Economic Evaluation

Cost Component		**T-D01**
Purchased equipment costs ($)	PEC	$ -
Other Direct Capital Costs 1 ($)	ODC1	$ -
Other Direct Capital Costs 2 ($)	ODC2	$ -
Indirect Capital Costs ($)	IDC	$ -
Total Capital Costs - Direct ($)	TCC	$ 67,834,200
Additional Capital ($)	AC	$ -
Total Capital Investment ($)	TCI	$ 67,834,200
Interest Rate (%)	R	10.50%
Useful Life (yr)	Y	25
Capital Recovery Factor	CRF	0.114
Annualized Capital Costs ($/yr)	ACC	$ 7,762,221
Incremental Annual (O&M) Costs ($/yr)	OMC	$ 6,552,797
Additional Electricity Demand ($/yr)	AED	$ 13,105,594
Associated non-electricity O&M ($/yr)	AOM	$ -
Annual Fuel Credit ($/yr)	AFC	$ (6,552,797)
Other Indirect Annual Costs ($/yr)	OAC	$ -
Total Annualized Costs ($/yr)	TAC	$ 14,315,018
NOx Control Efficiency (%)	Eff	100%

Baseline Actual NOx Emissions (ton/yr)	BAE	131.6
Future Utilization Adjustment (%)	FUA	0%
Projected Actual Emissions (ton/yr)	PAE	131.6
Estimated Reductions (ton/yr)	ER	131.6
2023$ Cost Effectiveness ($/ton)	**CE**	**$ 108,750**

estimates

Source
Included in TCC
Included in TCC
Included in TCC
Included in TCC
-
-
-
Enterprise Aug 2023 CBI update
Consistent with other FFAs
-
-
ERG calculation
Engineering judgement
ERG calculation
-
-
-

CY 2018 emissions testing and average operating hours (2016-2
Not specified by Enterprise
-
-
-

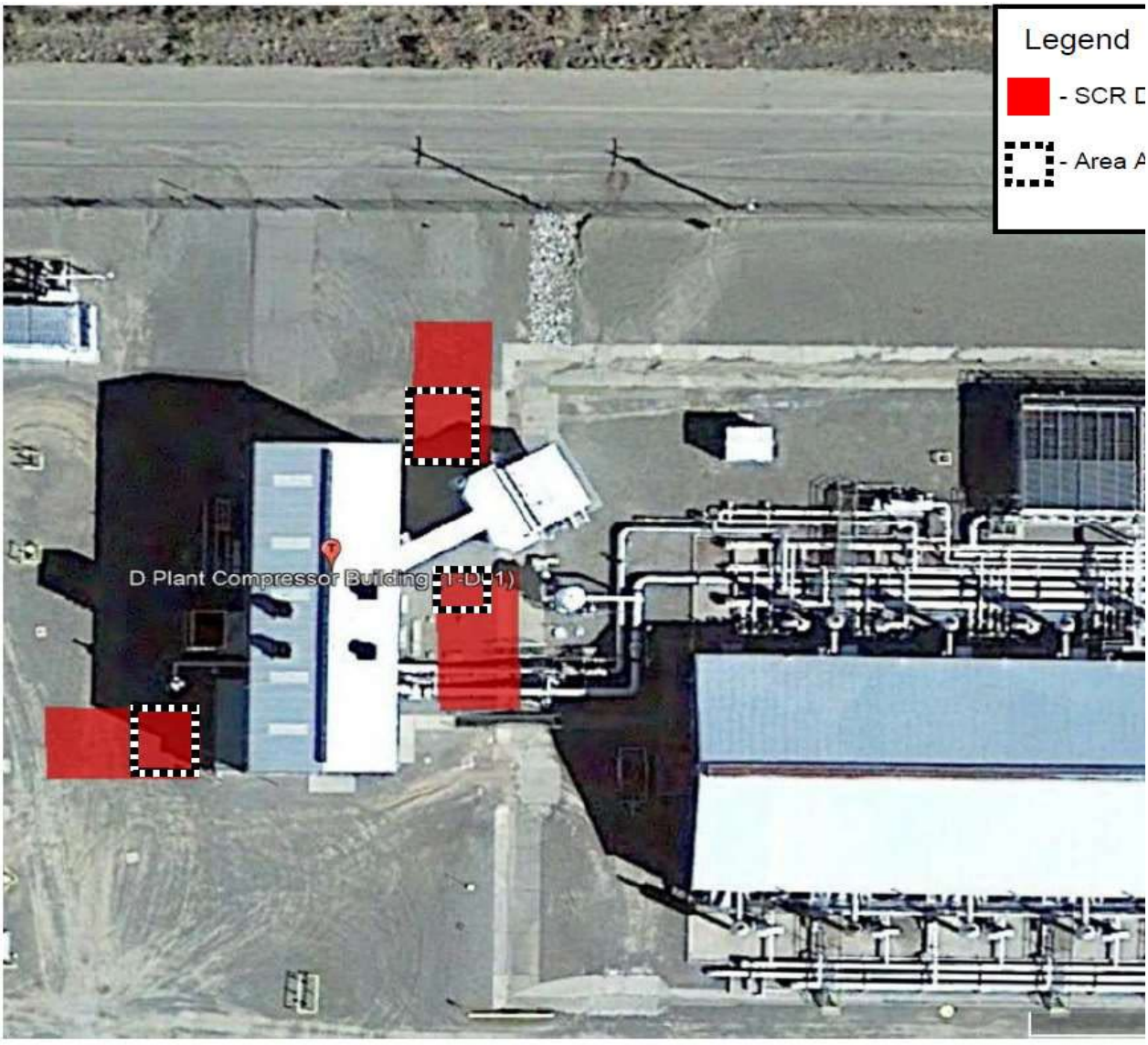
Methodology/Note
Enterprise provided a cost estimate for electrification using EPA Cost Control Manual Section 5.2, which pertains to acid gas scrubbers. As this is not applicable to replacement with EMD, a Total Capital Cost metric of $2,084 (2023$/hp) was calculated using detailed cost information provided by other facilities. The TCI figure assumes no costs associated with substation or distribution line upgrades. This assumption underestimates costs given that Enterprise indicated in its August 2023 update that utility infrastructure upgrades would be needed to support electrification at all three of its facilities.
TCC + AC
Standard CRF calculation
TCI x CRF
AED + AOM + AFC
Assumes unit at 60% load, 95% efficiency and a $0.10/kWh price
Assumed to be negligible
Assumed equal to 50% of AED
4% of TCI for conventional pollution controls; EPA has not evaluated administrative and other ancillary cc
ACC + OMC + OAC
No emissions from EMD units

021)
BAE x (1 + FUA)
PAE x Eff
TAC/ER

osts associated with replacement with an equivalent/like-kind unit

Enterprise indicated in its initial 2019 FFA submittal, 2020 follow-up and 2023 update that there is insuff
accommodate SCR. In support of its assertion, it indicated (2020 follow up) that CECO-Peerless stated th
approximately 40' x 20' is required for an SCR unit" and a copy of the correspondance was provided. An
facility was provided in the 2020 follow up which suggests that new buildings (or substantial extensions
building) would be required to house an SCR. The associated costs of building construction coupled with
exhaust system modifications would be costly. Considering the calculated cost effectiveness of SCR for
Mexico, it is reasonable to conclude that SCR is cost prohibitive for the Blanco C/D units.

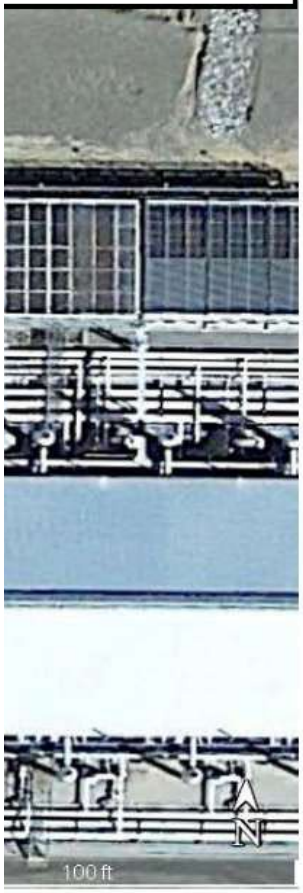
Image from 2/14/20 update
Aerial View of Blanco C/D



ïcient space to
ıat "an area of
aerial map of the
of the existing
ı corresponding
ɔther CTs in New

Dimensions

Available for SCR



Facility	Enterprise - Blanco C&D		
Unit	T-C01	T-C02	T-D01
2016 Hrs	8591	8505	8003
2017 Hrs	8603	8644	8617
2018 Hrs	8635	8692	8651
2019 Hrs	8357	8760	8558
2020 Hrs	8444	8634	8652
2021 Hrs	8663	8663	8628
2022 Hrs	8458	8442	8442
Rep Avg Period	2016-21	2016-21	2016-21
Average Hours	8549	8650	8518

Representa

Emissions Data (from Enterprise)			
Unit	T-C01	T-C02	T-D01
Date	2022	2022	2022
NOx (ppm)	41.5	53.4	50.2

Emissions Test Data (from Reports)			
Unit	T-C01	T-C02	T-D01
Test Date	10/3/2018	10/2/2018	10/1/2018
Load during test (%)	98%	96%	96%
Power Output (hp)	21,834.4	21,388.8	21388.8
NOx (ppm)	45.94	63.24	53.02
NOx (lb/hr)	32.04	43.3	29.67
NOx (g/hp-hr)	NP	NP	NP
NOx (lb/MMBtu)	NP	NP	NP

NP - Not Provided

Additional Info			
Unit	T-C01	T-C02	T-D01
Nameplate Power (hp)	22,280	22,280	32,550

Calculations			
Unit	T-C01	T-C02	T-D01
NOx (lb/hr, @100% load)	32.7	45.1	30.9
NOx (g/hp-hr)	0.67	0.92	0.43

ıtive averaging period per NMED analysis; 2022 data excluded because it was still preliminary at time of a

analysis

CPI

Year	CPI
1999	0.65
2000	0.67
2018	0.98
2019	1
2020	1.02
2021	1.04
2022	1.12
2023	1.19

Enterprise indicated in its initial 2019 FFA submittal, 2020 follow-up and 2023 update that there is insuff
accommodate SCR. In support of its assertion, it indicated (2020 follow up) that CECO-Peerless stated th
approximately 40' x 20' is required for an SCR unit" and a copy of the correspondance was provided. An
facility was provided in the 2020 follow up which suggests that new buildings (or substantial extensions
building) would be required to house an SCR. The associated costs of building construction coupled with
exhaust system modifications would be costly. Considering the calculated cost effectiveness of SCR for
Mexico, it is reasonable to conclude that SCR is cost prohibitive for the Chaco units.

Image from 2/14/20 update
Aerial View of Chaco



ïcient space to
ıat "an area of
aerial map of the
of the existing
ı corresponding
ɔther CTs in New



Attachment C

Solar Turbines
A Caterpillar Company

Solar Turbines Incorporated

9330 Sky Park Court
San Diego, CA 92123
Tel: (858) 694-1616

Submitted Electronically

September 9, 2024

Subject: **Solar Compressor Sets - NOx Reductions per NM Regional Haze Rule Requirements**

There are very few gas turbine compressor sets in the world equipped with SCR systems. While a 90% NOx reduction rate is generally applicable to base-loaded generator sets producing electrical energy usually in combined cycle or cogeneration configurations, the same NOx reduction cannot be assumed for compressor sets which operate in simple cycle mode and experience variable loads swings as part of normal operations.

For reference, there are two compressor stations in Virginia with Solar Turbines equipped with SCR systems. NOx limits for these stations are based on approximately a 60% reduction from the SCR systems. 60-80% NOx reduction is a more realistic range of NOx reduction achievable with SCRs placed on gas turbine compressor sets.

The Solar Centaur 40 and Mars 100 gas turbines at South Carlsbad Station and the Chaco Gas Plant, respectively are of the vintage diffusion flame version of gas turbines which have higher NOx emissions than modern dry-low emissions (DLE) gas turbines sold today. Solar offers upgrades for these turbines to DLE versions (termed 'SoLoNOx' – Solar's DLE system) which will reduce NOx emissions greater than SCR systems with the added benefit of avoiding NH3 emissions which are produced by the SCR process. The SoLoNOx upgrades will also be less costly and require much less unit downtime than SCR installation.

Specifically, Solar offers SoLoNOx upgrades on these units to levels of 15 ppm NOx for the Centaur 40 and to 9 ppm NOx for the Mars 100. The SoLoNOx levels represent NOx reductions of greater than 90% from the existing diffusion flame configurations.

In summary, upgrading the existing Solar turbines at South Carlsbad Station and the Chaco Gas Plant to modern SoLoNOx combustion systems is a more cost-effective and environmentally beneficial solution than retrofitting to SCR.

Please call me at 858.505.8554 if you have any questions.

Sincerely,

Anthony Pocengal
Solar Turbines Incorporated

cc: Joey Guillen, Solar Turbines Incorporated

Caterpillar: Confidential Green


















January 7, 2025

Raquel Chavez & Josh Hirsch
New Mexico Environment Department
Harold Runnels Building
1190 St. Francis Dr. Suite N4050
Santa Fe, NM 87505

Re: Revisions to the New Mexico Environment Department's Regional Haze Draft State Implementation Plan and Companion Rule 20.2.68 NMAC.

Dear Ms. Chavez and Mr. Hirsch,

The Western Environmental Law Center, on behalf of Citizens Caring for the Future, Conservation Voters New Mexico, Diné C.A.R.E., National Parks Conservation Association, New Mexico Interfaith Power and Light, Sierra Club, and San Juan Citizens Alliance (Conservation Groups), respectfully submits the following comments on and recommendations for the New Mexico Environment Department's (NMED) draft revisions to the Regional Haze State Implementation Plan (SIP) for the second planning period and companion rule, 20.2.68 NMAC.

While Conservation Groups generally support the revised draft SIP, we urge NMED to address the issues raised below. Specifically, while we do not oppose NMED's changes to the control efficiency for selective catalytic reduction (SCR) controls at intermittently operated sources and use of the Chemical Engineering Plant Cost Indices (CEPCI), NMED must further revise its control cost analyses to correct other control cost parameters that affect the cost-effectiveness of controls analyzed. NMED adopted shortened remaining useful lives for a number of the controls analyzed even though the revised SIP does not indicate that there are federally enforceable requirements that justify the use of a shortened useful life. NMED also used interest rates that are higher than the current bank prime rate of 7.5%. Thus, many of the controls analyzed are likely

much more cost-effective than NMED's analyses in the revised SIP currently show. Additionally, NMED's use of 90% control efficiency for SCR on gas-fired combustion turbines was well supported, and NMED must provide additional source-specific information to support the reduction in control efficiency for each facility for which it reduced the SCR control efficiency. In accordance with the discussion below, we request that NMED amend its control cost analyses to accurately reflect the cost-effectiveness of controls analyzed.

I. NMED Should Use a Longer Remaining Useful Life for Controls Analyzed.

When determining the reasonable progress measures for a source, NMED must consider four factors: the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of the source.[1] As EPA has explained, "[t]he remaining useful life factor is closely related to the cost of compliance factor, with the calculated cost of compliance generally increasing with a shorter remaining useful life."[2] Thus, to assume a shortened remaining useful life, the state must provide a federally enforceable requirement for the facility to shutdown or some other enforceable requirement to justify the shortened remaining useful life.[3]

Here, NMED assumed a shorter remaining useful life for a number of the controls analyzed than what other agencies, including EPA, and facilities use to assess these controls. For example, NMED adopted a 20-year remaining useful life when assessing selective catalytic reduction (SCR) controls for gas-fired combustion turbines. However, EPA has found that SCR on gas-fired turbines in an industrial setting has a remaining useful life of 25 years.[4] NMED similarly assumed a 20-year remaining useful life for dry low NOx burners (DLN) on combustion

[1] 42 U.S.C. § 7491(g)(1); 40 C.F.R. § 51.308(f)(2)(i).
[2] Memorandum from Peter Tsirigotis, Dir., Env't Prot. Agency, to Reg'l Air Dirs., Regions 1-10 at 20 (Aug. 20, 2019), https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.
[3] *Id.* at 34 (explaining that, "[i]n the situation of an enforceable requirement for the source to cease operation before the end of the useful life of the controls under consideration, a state may use the enforceable shutdown date as the end of the remaining useful life," as long as the SIP includes the shutdown date (citing 40 C.F.R. § 51.308(f)(2)); Memorandum from Peter Tsirigotis, Dir., Env't Prot. Agency, to Reg'l Air Dirs., Regions 1-10 at 10 (July 8, 2021), https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf (explaining that, if a state relied on a source shutdown or retirement to, for instance, "shorten the remaining useful life of a source," then that source retirement is "necessary to make reasonable progress and must be included in a SIP").
[4] Vicki Stamper & Megan Williams, Oil and Gas Sector Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories at 76 (March 6, 2020) [hereinafter "Oil and Gas 4FA Report"] (citing Envtl. Prot. Agency, Air Pollution Control Cost Manual, Section 4: NOx Controls, Chapter 2: Selective Catalytic Reduction at PDF 80 (2019), https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf [hereinafter "CCM SCR Chapter"). The Oil and Gas 4FA Report is attached to these comments as Exhibit 1.

turbines, but these controls should have a 25-year remaining useful life.[5] For gas-fired lean burn reciprocating internal combustion engines (RICE) with low emission combustion (LEC), NMED used a remaining useful life of 20 years when these controls should have a useful life of 25 years.[6] At the very least, NMED must assume a useful life that is equivalent to RICE without LEC. Finally, NMED adopted a short 20-year remaining useful life for gas-fired boilers with SCR at the Cunningham Station Power Plant, despite the fact that there is ample support for a 30-year useful life for SCR on these sources, including EPA's Control Cost Manual (CCM).[7]

Yet, nothing in the revised SIP indicates that any federally enforceable requirements justify the use of a shortened remaining useful life for these controls at any of the sources analyzed. NMED must revise the remaining useful life used in its control cost analyses to accurately reflect the expected and proven useful life of these controls. By correcting the remaining useful life for controls considered, NMED would likely find that the controls are much more cost-effective than the revised SIP currently shows.

II. NMED's Use of an 8.5% Bank Prime Interest is Inappropriate.

Conservation Groups urge NMED to revise its calculations to reflect a more current bank prime interest rate. Throughout its analysis, NMED applies a default interest rate of 8.5%, unless a different rate is specified by an operator. Although this rate was appropriate when NMED initially performed its analysis,[8] the bank prime interest rate has dropped by a full percentage point,[9] rendering capital investment markedly more cost effective than it would have been a year ago. NMED should adopt a default interest rate of 7.5% and revise its calculations accordingly.

Additionally, for the facility-provided interest rates, NMED must ensure that the facilities have adequately documented and supported the claimed interest rates to support the control cost analyses. The Regional Haze Rule requires that NMED "must document the technical basis, including . . . cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress."[10] Some of the facility-specific interest rates on which NMED relies in the revised SIP are

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[5] Oil and Gas 4FA Report at 69-70 (explaining that DLN should be expected to last for the life of the combustion turbine and noting examples of DLN retrofits on combustion turbines that have operated for at least 25 years).

[6] Notably, several New Mexico sources assumed a 25-year remaining useful life in their facility-submitted four-factor analyses for LEC, demonstrating that LEC can achieve a longer useful life than NMED assumed in its analyses. *See, e.g.*, NM Env't Dep't, State of New Mexico Revised Proposed Reginoal Haze State Implementation Plan Revision Second Planning Period (2019-2028) at PDF 1264, 1268-69, 1271, 1299 (revised Dec. 13, 2024) (Clean) [hereinafter "Clean Revised SIP"] (Mountainair Compressor Station No. 7 four-factor analysis stating that LEC controls have a 25-year remaining useful life); *id.* at 1318, 1326, 1368 (Roswell Compressor Station four-factor analysis stating that LEC controls have a 25-year remaining useful life).

[7] CCM SCR Chapter at PDF 80 (noting a 30-year remaining useful life for SCR on power plant turbines).

[8] NMED states that this rate was current on Oct. 31, 2023.

[9] *See, e.g.*, https://www.wsj.com/market-data/bonds/moneyrates.

[10] 40 C.F.R. § 51.308(f)(2)(iii).

significantly higher than the current bank prime interest rate,[11] which also significantly affects the cost effectiveness of the controls analyzed. Thus, NMED must ensure that the facility-specific interest rates are adequately documented, as required by the Regional Haze Rule, and if the facility rate is not properly supported, NMED must use the bank prime rate, in accordance with EPA's CCM.

III. NMED's Assumption of a 90% NOx Removal Efficiency for SCR Was Reasonable.

Although Conservation Groups do not oppose NMED's reduction of the assumed NOx removal efficiency for SCR to 80%, NMED's initial assumption of 90% was reasonable and would have resulted in greater progress towards the Regional Haze Program's natural visibility goal. Ample evidence supports that SCR can achieve up to 90% or higher control efficiency for NOx on gas-fired combustion turbines.[12] However, NMED's assumption of 80% control may be valid if a facility is operated intermittently, as incomplete combustion during start up or shut down periods can result in higher NOx emissions. Thus, to justify reducing the assumed control efficiency for SCR on gas-fired turbines to 80%, NMED must provide more information about facilities' operations to support that efficiency. Specifically, NMED must demonstrate that the gas turbines for which it switched to 80% control are, indeed, operated only intermittently based on plant-specific operating conditions for each unit.[13] Data reported by facilities indicate variability in operating hours, which may indicate intermittency, but also show that some turbines have operated at 8,000+ hours in a year,[14] which is inconsistent with intermittent operation.[15] Moreover, lower operating hours are not necessarily indicative of highly intermittent operation, as the critical variable is the time during which a facility is starting up or shutting down. Accordingly, NMED must further justify and provide adequate documentation to support its

[11] *See, e.g.*, Clean Revised SIP, App. C: Four-Factor Analyses Supporting Documentation at PDF 365 (stating that Enterprise provided a 10.5% facility-specific interest rate for its Blanco C&D Compressor Station control analyses).
[12] Oil and Gas 4FA Report at 73-80.
[13] *See* 40 C.F.R. § 51.308(f)(2)(iii). The units affected by this change include Linam Ranch SCR, (PDF 338), Pecos River CS (PDF 360), Blanco CD CS (pdf 373), Chaco Gas Plant (pdf 382), South Carlsbad CS (pdf 392), Mountainair CS (pdf 401), Roswell CS (pdf 409), Kutz Canyon Process Plant (PDF 416), San Juan Basin Gas Plant (PDF 425), Indian Basin Gas Plant (PDF 441)
[14] There are 8,760 hours in a year.
[15] *See, e.g.*, Clean Revised SIP: App. C: Four-Factor Analyses Supporting Documentation at PDF at 330 (showing that turbine 29 at the Linam Ranch Gas Plant operated for more than 8,000 hours in all but one year from 2016 to 2022 and that turbine 31 operated for more than 8,000 hours in all years from 2016 to 2022); *id.* at PDF 362 (showing that all turbine units at the Blanco C&D Compressor Station have operated for more than 8,000 hours in the years from 2016 to 2022); *id.* at PDF 370-71 (showing that multiple turbine units at the Chaco Gas Plant operated for more than 8,000 hours for multiple years from 2016 to 2022); *id.* at PDF 381 (showing that both turbines at South Carlsbad Compressor Station operated for more than 8,000 hours in all years from 2016 to 2022); *id.* at PDF 413 (showing that multiple turbine units at the San Juan Basin Gas Plant operated for more than 8,000 hours for multiple years from 2016 to 2022).

reduction to 80% efficiency,[16] and oppose any further weakening of the NOx removal efficiency figure.

IV. Conclusion.

Conservation Groups appreciate the opportunity to comment on this revised draft SIP. We encourage NMED to apply an appropriate remaining useful life of controls and bank prime interest rate, and we oppose any further weakening of the NOx removal efficiency figure.

Sincerely,

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[16] 40 C.F.R. § 51.308(f)(2)(iii) (requiring that states "document the technical basis, including . . . cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress.").

Exhibit 1

OIL AND GAS SECTOR
REASONABLE PROGRESS
FOUR-FACTOR ANALYSIS OF CONTROLS
FOR FIVE SOURCE CATEGORIES:

NATURAL GAS-FIRED ENGINES
NATURAL GAS-FIRED TURBINES
DIESEL-FIRED ENGINES
NATURAL GAS-FIRED HEATERS AND BOILERS
FLARING AND INCINERATION

Prepared for National Parks Conservation Association

by Vicki Stamper & Megan Williams

March 6, 2020

EXECUTIVE SUMMARY

States are required to revise and submit revisions to their regional haze state implementation plans to make reasonable progress toward the national visibility goal, with the next revision due to the U.S. Environmental Protection Agency by July 31, 2021. In this second round of regional haze plans, each state needs to look broadly at the sources of visibility-impairing emissions within its state and determine the sources or source categories for which to conduct a four-factor analysis of emission reducing measures. Oil and gas development is a significant source of visibility-impairing emissions in many states, including emissions of nitrogen oxides (NOx), volatile organic compounds (VOCs), sulfur dioxide (SO_2), and particulate matter (PM).

This report conducts a four-factor analysis of reasonable progress controls for five air emission source categories within the oil and gas development industry: natural gas-fired reciprocating internal combustion engines (RICE), natural gas-fired combustion turbines, diesel-fired RICE, natural gas-fired heaters and boilers, and flaring. This report includes a compilation of information on available pollution control options for visibility-impairing pollutants, provides cost of controls (where available) and documents the cost effectiveness of controls for various size units and a range of operating levels. The report also provides information for specific pollution controls regarding the three other reasonable progress factors: the time necessary for compliance to install the controls, the energy and non-air quality environmental impacts of the controls, and the remaining useful life of both the source category and the pollution control in question, if it differs from that of the source category.

With respect to the cost of controls, the authors used control cost data that were relied upon by federal, state, and local air agencies. Also, capital costs of control were amortized based on the expected useful life of the unit unless a shorter useful life of the specific pollution control was expected, all of which is documented in the report. The authors did not escalate costs to current dollars, because in many cases, the cost information was more than five years old, and EPA's Control Cost Manual cautions against attempting to escalate costs more than five years from the original cost analysis. Last, the authors compiled information on federal, state, and local air emission limitations that were required to be met by existing sources and thus required a retrofit of pollution controls to the source category. This assessment includes an evaluation of the lowest emission limits required of existing sources by state and local agencies and correlates those emission limits to specific pollution controls. Looking to state regional haze plans, the authors note that determinations of cost effectiveness for a particular source category should be based on the costs that similar sources have had to incur to meet Clean Air Act requirements.

Although the authors attempted to identify the pollution control methods that were both cost effective and the most effective at reducing visibility-impairing emissions and evaluated varying levels of operation, it is recognized that air pollution control determinations to retrofit existing sources cannot always be implemented via a "one-size-fits-all" approach. Thus, in some cases, a few different options for retrofit pollution controls are recommended for a source category, with the primary reasons for differentiating recommended pollution controls being based on size of the unit and/or operating capacity factor. Below the authors summarize the pollution controls that are presumed to be the best control options for each source category, with a focus on NOx pollution controls.

Summary of Cost Effective Control Options for Air Emissions Sources of the Oil and Gas Sector

SOURCE CATEGORY	NOx POLLUTION CONTROL	NOx COST EFFECTIVENESS ($/TON)	PERCENT NOx REMOVAL, AND EMISSION RATES	OTHER POLLUTION CONTROLS
Natural Gas (NG)-Fired RICE Compressors	Replace with Electric Compressors	$1,228–$2,766/ton (2011 $)	100% Removal of NOx and All Other Pollutants	Power Compressors with Renewable Energy
NG-Fired RICE Rich Burn >50 hp	Nonselective Catalytic Reduction (NSCR) and Air Fuel Ratio Controller (AFRC)	$44–$3,383/ton (2009$)	94–98% 11–67 ppmv 0.16–1.0 g/hp-hr	VOC Controls integrated into NSCR.
NG-Fired RICE Lean Burn >50 hp	Low Emission Combustion (LEC)	$47–$941/ton (2001$)	87–93% 75–150 ppmv 1.0–2.0 g/hp-hr	Oxidation Catalyst for VOC Emissions
	Selective Catalytic Combustion (SCR)	$628–$13,567/ton (1999$–2001$)	90–99% 11–73 ppmv 0.15–1.0 g/hp-hr	
NG-Fired Combustion Turbines	SCR (alone or with Dry Low NOx Combustion)	$566–$13,238/ton (1999–2000$)	80–95+% 3-15 ppmv	Oxidation Catalyst for VOC Emissions
	Dry Low NOx Combustion	$208–$2,140/ton (1999$–2000$)	80–95% 9-25 ppmv	
Diesel-Fired RICE	Use Electric Engines and Tier 4 Gen Sets ---------- OR Replace Older Engines w/ Tier 4	$564–$9,921/ton (2010$)	94% 0.5 g/hp-hr ---------- 49%–96% 0.3-3.5 g/hp-hr	Catalytic Diesel Particulate Filter For PM (81%-97.5% control) Use of Ultra-Low Sulfur Diesel Fuel
	Replace w/ NG RICE	Implemented by several companies	85–94%	
	Retrofit with SCR	$3,759–$6,781/ton	90%	
Heaters/Boilers >20 MMBtu/hr	Ultra-Low NOx Burners (ULNB)	$545–$3,270/ton (2018$)	93% 6 ppmv	Other Options: Lower heater-treater temperatures Install insulation on separators
	SCR	$1,025–$6,149/ton (2018$)	97% 2.5 ppmv	
Heaters/Boilers >5 and ≤20 MMBtu/hr	ULNB	$727–$5,232/ton (2018$)	93% 6 ppmv	
Heaters/Boilers ≤5 MMBtu/hr	Replacement of Heater with New Unit with ULNB	$4,055-$10,809/ton (2005$)	82–89% 9-20 ppmv	

Note: The range of cost effectiveness for each control reflects a range of capacities of emission units and also reflects a wide range of operating hours per year. Refer to the report for more details.

As shown in the table above, there are technically feasible and cost effective options to control NOx, VOCs, PM, and SO2 from these four source categories of combustion-related emissions from the oil and gas sector and, in most cases, there are many examples of state and local air agency rules that require these or similar levels of control for existing sources. While many of these state and local rules were adopted to address the National Ambient Air Quality Standards (NAAQS), cost effectiveness of controls is generally part of the rulemaking process under reasonably available control technology (RACT) and best available retrofit control technology (BARCT – which applies in California) determinations. Given that state and local air agencies have found the costs of these controls to be reasonable for imposition of various pollution control requirements, these costs should be considered reasonable to impose to meet other Clean Air Act requirements including under the Regional Haze Program.

For flaring of waste gases, the following control options are recommended:

- Prevent flaring of excess gases through capture and use requirements instead of flaring
- Prevent flaring at gas sweetening and other processing plants by proper maintenance, training, installing duplicative equipment to minimize upsets
- Require documentation of flaring episodes with all relevant info to estimate emissions and to assess causes and actions to mitigate
- Thermal incineration should be considered in lieu of flaring due to ability for improved VOC destruction and available NOx and SO2 controls (if sour/acid gas is being combusted)

The ultimate goal to reduce VOC, NOx, PM, and SO2 emissions from excessive flaring should be to eliminate or minimize flaring to the maximum extent possible and to use, and not waste, excess gas produced.

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LIST OF TERMS

2SLB	Two-stroke lean-burn
4SLB	Four-stroke lean-burn
4SRB	Four-stroke rich-burn
A/F	Air-to-fuel ratio
ACT	Alternative control techniques
AFRC	Air/fuel ratio controller
APCD	Air pollution control district
AQMD	Air Quality Management District
BACT	Best Available Control Technology
BARCT	Best Available Retrofit Control Technology
BART	Best Available Retrofit Technology
BAT	Best Available Technology
BSFC	Brake-specific fuel consumption
BLM	U.S. Bureau of Land Management
CARB	California Air Resources Board
CEPCI	Chemical Engineering Plant Cost Index
CAA	Clean Air Act
CDPF	Catalyzed diesel particulate filter
CDPHE	Colorado Department of Public Health and Environment
CI	Compression ignition
CEMS	Continuous emissions monitoring system
CO	Carbon monoxide
CO_2	Carbon dioxide
CSAPR	Cross-State Air Pollution Rule
DRE	Destruction and removal efficiency
DPF	Diesel particulate filter
DOE	U.S. Department of Energy
DLNC	Dry low NOx combustors
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
FGR	Flue gas recirculation
4CAQTF	Four Corners Air Quality Task Force
GPU	Gas production unit
Gen Set	Generator-Set Engine
g/bhp-hr	Grams per brake horsepower-hour
g/hp-hr	Grams per horsepower-hour
HAP	Hazardous air pollutant

LIST OF TERMS

HC	hydrocarbon
H_2S	Hydrogen sulfide
hp	horsepower
kW	Kilowatt
INGAA	Interstate Natural Gas Association of America
IR	Ignition timing retard
LB	Lean-burn
LEC	Low emission combustion
LNB	Low NOx burners
MCF	Thousand cubic feet
MW	Megawatt
MMBtu	Million British Thermal Unit (heat input)
MMscf	Million standard cubic feet
NAAQS	National Ambient Air Quality Standards
NESCAUM	Northeast States for Coordinated Air Use Management
NESHAP	National Emission Standards for Hazardous Air Pollutants
NPS	National Park Service
NSPS	New Source Performance Standards
NOx	Nitrogen oxides
NMHC	Non-methane hydrocarbons
NSCR	Nonselective catalytic reduction
NSPS	New Source Performance Standards
OTC	Ozone Transport Commission
PEMS	Parametric emissions monitoring system
PM	Particulate matter
$PM_{2.5}$	Particulate matter with an aerodynamic diameter equal to or less than 2.5 microns
ppm	Parts per million
ppmv	Parts per million by volume
ppmvd	Parts per million dry volume
PSC	Prestratified charge
PSD	Prevention of Significant Deterioration
psig	Pounds per square inch gauge
RACT	Reasonably Available Control Technology
RECLAIM	Regional Clean Air Incentives Market
RHR	Regional Haze Rule
RB	Rich-burn
RICE	Reciprocating internal combustion engine(s)

LIST OF TERMS

SMAQMD	Sacramento Metropolitan Air Quality Management District
SCAQMD	South Coast Air Quality Management District
SCR	Selective catalytic reduction
SI	Spark ignition
SJVAPCD	San Joaquin Valley Air Pollution Control District
SNCR	Selective noncatalytic reduction
SO_2	Sulfur dioxide
SOx	Sulfur oxides
TCEQ	Texas Commission on Environmental Quality
TSD	Technical support document
THC	Total hydrocarbons
ULSD	Ultra-low sulfur diesel
ULNB	Ultra-low NOx burners
VCAPCD	Ventura County Air Pollution Control District
VOC	Volatile organic compound

I. BASIS FOR REASONABLE PROGRESS CONTROLS

Under the Regional Haze Rule (RHR), states are required to revise and submit periodic comprehensive revisions to their regional haze plans, with the next revision due to be submitted to the U.S. Environmental Protection Agency (EPA) by July 31, 2021.[1] This next round of regional haze plans is referred to as the regional haze plan for the second implementation period. States' regional haze plans address regional haze in all Class I areas within the state and in all Class I areas located outside the state that may be affected by emissions from within the state.[2] Each state's plan and plan revision must include, among other things, a long term strategy which is to be determined as follows:

> Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State that may be affected by emissions from the State. The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress, as determined pursuant to [40 C.F.R. § 51.308] (f)(2)(i) through (iv). In establishing its long-term strategy for regional haze, the State must meet the following requirements:
>
> (i) The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment. The State should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. The State must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress.
>
> . . .

40 C.F.R. § 51.308(f)(2)(i).

The requirement for evaluation of emission reduction measures quoted above is generally referred to as a "four-factor analysis" or a "reasonable progress analyses" of controls. To reiterate, the four factors that must be considered when evaluating reasonable progress controls for a source are (1) cost of compliance, (2) time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of the source. In the first round of regional haze plans, States were required to evaluate and impose emission limitations that reflect "best available

[1] 40 C.F.R. § 51.308(f).
[2] *Id.*

retrofit technology" (BART) at all BART-subject sources (which were clearly defined by regulation). States also were required to identify sources to control in order to make reasonable progress towards the national visibility goal; for these sources states tended to focus on the larger single sources of emissions, as was also the focus of BART controls. In the second round of regional haze plans, each state needs to look more broadly at the sources of visibility-impairing emissions within its state and determine the sources or source categories for which to conduct a four-factor analysis of controls. Each state must adopt emission-reduction measures in its regional haze plan developed for the second implementation period to make reasonable progress towards the national visibility goal. The Clean Air Act (CAA) mandated that regional haze plans must address sources of "emissions from which may reasonably be anticipated to cause or contribute to ***any*** impairment of visibility" (emphasis added)).[3]

Air emissions from oil and gas development, production, treatment, and transmission represent a significant quantity of regional haze-impairing emissions in many states. Air emissions from oil and gas development that can impact visibility include nitrogen oxides (NOx), sulfur dioxide (SO_2), directly emitted particulate matter (PM), volatile organic compounds (VOCs), and ammonia. NOx, SO_2, VOCs, and ammonia, initially emitted as gases, often convert into fine (i.e., less than 2.5 micrometers in diameter) particulate matter ($PM_{2.5}$) in the atmosphere, which can travel far and which are very efficient in scattering light and impacting visibility. Oil and gas development often occurs on federal, state, and/or private lands near or even adjacent to Class I areas. Oil and/or gas development tends to be clustered in certain areas where such fossil fuels are found. Many of the air emissions sources associated with gas and/or oil production are minor sources, not large enough in emissions to trigger new source review permitting. However, such sources collectively are often significant contributors to visibility impairment in Class I areas due to sheer numbers of emission sources or proximity to Class I areas, or both.

In the United States, oil and gas production has been increasing and is projected to continue to increase in the future. States with significant increases in oil production since 2013 include Colorado with almost a tripling of production since 2013, New Mexico with more than a doubling of production since 2013, Texas with a 73% increase in production since 2013, and North Dakota with a 48% increase since 2013.[4] States with significant increases in gas production include, among others, Ohio with annual gas production in 2018 that is more than 14 times higher than it was in 2013, West Virginia with a 143% increase in gas production since 2013, North Dakota with a doubling of production in 2018 compared to 2013, Pennsylvania with a 91% increase in gas production since 2013, and New Mexico with a 27% increase in gas production since 2013.[5] The U.S. Energy Information Administration (EIA) currently projects crude oil production in the United States to be 25% higher in 2021 than it was in 2018[6] and marketed gas production in the United States to be 13% higher in 2021 than it was in 2018.[7] In many areas of the country, these increases in production are projected to continue well into the future. For

[3] 42 U.S.C. § 7491(b)(2).
[4] EIA, Crude Oil Production, Annual-Thousand Barrels, 2013 to 2018, *available at:* https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm.
[5] EIA, Natural Gas Gross Withdrawals and Production, Marketed Production, Annual Million Cubic Feet, 2013 to 2018, *available at:* https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm.
[6] EIA Short-Term Energy Outlook, U.S. Liquid Fuels, January 14, 2020, *available at:* https://www.eia.gov/outlooks/steo/report/us_oil.php.
[7] EIA, Short-Term Energy Outlook, Natural Gas, January 14, 2020, *available at:* https://www.eia.gov/outlooks/steo/report/natgas.php.

example, the New Mexico Oil and Gas Association recently presented a report to state lawmakers indicating that there will be "solid growth for the next decade or so" in the Permian Basin.[8]

There are several combustion-related sources of visibility-impairing emissions associated with oil and gas development. Various engines, typically fired by natural gas or diesel, are used in the drilling and completion phase, in the processing of natural gas, and at compressor stations. On-site power sources are often used, in the form of natural gas-fired engines, diesel generators, and/or combustion turbines. Natural gas-fired boilers and heaters are also used throughout the oil and gas production and process segments of the industry, to generate power, and to create steam and process heat. Those engines and combustion turbines emit significant quantities of NOx and VOCs and also of SO_2 and PM for diesel-fired engines. Flaring of excess and waste gas can be a significant source of SO_2 and NOx emissions.

This report presents a four-factor analysis of reasonable progress controls for NOx and VOCs, and SO_2 and PM as appropriate, for five significant air emissions source categories associated with oil and gas development: natural gas-fired reciprocating internal combustion engines (RICE), natural gas-fired combustion turbines, diesel-fired RICE, natural gas-fired boilers and heaters, and flaring/incineration of waste or excess gas. This report (1) proposes pollution controls and/or measures for such sources considering the control technology available and the most effective controls; (2) compiles cost data with a focus on data relied upon by federal, state, and local air agencies in regulatory decisions; (3) evaluates non-air quality environmental and energy impacts of controls; and (4) considers the remaining useful life of the equipment.

It is important to note that, while New Source Performance Standards (NSPS) exist for these source categories, the existence of an NSPS does not negate the need for a four-factor analysis of controls to achieve reasonable progress towards the national visibility goal for several reasons. First, it has been many years since the NSPS standards for RICE units, gas turbines, and small boilers have been re-evaluated. Although EPA correctly states in its 2019 Regional Haze guidance that "[t]he [CAA] requires EPA to review, and if necessary, revise NSPS every 8 years,"[9] EPA has not always updated the NSPS emission standards for a source category in accordance with this timetable. Second, the NSPS emission standards only apply to a facility if it is constructed, modified, or reconstructed after the applicability date.[10] The applicability date of an NSPS (or of a revised NSPS emission standard) is set as either the date of publication of any proposed or of any final rulemaking establishing the standard. Third, when EPA adopts or revises NSPS for a source category, EPA is establishing an emission standard applicable to all of the source types and variable fuels, operating conditions, etc. that exist for that source category. Thus, the NSPS are generally applicable emission standards and not a source-specific evaluation of controls.

Further, while EPA's Regional Haze guidance states that, if a new or modified unit is subject to and complying with an NSPS promulgated or reviewed since July 31, 2013, it is unlikely that new or existing controls are available or more effective, no such assumption should be made without considering the

[8] As discussed in Report: New Mexico oil, gas boom to continue, by Susan Montoya Bryan/Associated Press, September 3, 2019, Albuquerque Journal, *available at:* https://www.abqjournal.com/1361629/report-new-mexico-oil-gas-boom-to-continue.html.

[9] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 23, note 44.

[10] *See* 40 C.F.R. § 60.1(a); *see also* definitions in § 60.2 and regulations on "modification" and "reconstruction" in §§ 60.14 and 60.15.

specific emission and operational characteristics of the source in question. EPA's statements are problematic and need clarification. One cannot simply determine the last time the NSPS for a source category was amended and assume that if the amendments occurred within the last eight years, the NSPS is up to date. Section 111(b)(1)(B) of the CAA requires EPA to review and revise each NSPS at least every eight years, to essentially determine if the NSPS currently reflect the "degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[11] EPA amends its NSPS for various reasons (e.g., changes in test methods or protocols, clarifications), but thorough reviews and revisions generally occur much less frequently — in many cases less frequently than every eight years as required by the CAA. Table 1 below shows the NSPS applicable to RICE units, turbines, and small boilers and provides the most recent date of EPA's comprehensive review and revision. The NSPS rules applicable to RICE units and gas turbines were last subject to a comprehensive revision to reflect the best-demonstrated technology well before July 31, 2013.

Table 1. NSPS Categories that Address RICE, Natural Gas Turbines, and Small Boilers

NSPS Subpart in 40 C.F.R. Part 60	Emission Source(s)	Date of Promulgation of Most Recent Revisions
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	2/27/06 (reflects most recent review of the emission standards)
GG	Stationary Gas Turbines	9/20/79 (first promulgation of NSPS for gas turbines and revised standards promulgated at Subpart KKKK)
IIII	Stationary Compression Ignition Internal Combustion Engines	6/28/11 (reflects most recent adoption of emission standards for this source category)
JJJJ	Stationary Spark Ignition Internal Combustion Engines	1/18/08 (NSPS for source category first promulgated, and reflects most recent review of emission standards)
KKKK	Stationary Combustion Turbines constructed, reconstructed or modified after 2/18/05	7/6/2006 (first promulgation of NSPS Subpart KKKK, and reflects most recent review of emission standards)
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution for which Construction. Modification, or Reconstruction Commenced after 8/23/11 and on or before 9/15/15	6/3/2016 (reflects most recent review the emission standards)
OOOOa	Crude Oil and Natural Gas Production, Transmission, and Distribution from which Construction. Modification, or Reconstruction Commenced after 9/18/15	6/3/2016 (NSPS Subpart first promulgated)

[11] *See* Section 111(a)(1) of the Clean Air Act, 42 U.S.C. § 7411(a)(1).

Thus, while the NSPS may be a place to start in evaluating pollution controls for air emissions sources associated with the oil and gas industry, it is also necessary to evaluate if more stringent requirements and pollution controls have been required in state rules or local air rules, air permits, or other requirements. Review of state regulations and state implementation plans, particularly to address national ambient air quality standards (NAAQS) which requires reductions in emissions from existing sources, is necessary to fully evaluate controls for emission sources associated with oil and gas development to achieve reasonable progress towards the national visibility goal.

The information provided below reflects a comprehensive review of the pollution controls and techniques and associated emissions levels applicable to each of the source categories, along with data on cost of controls where available, non-air quality environmental and energy impacts, and the reasonable useful life of the emission source being evaluated.

II. CONTROL OF NOx EMISSIONS FROM NATURAL GAS-FIRED RECIPROCATING INTERNAL COMBUSTION ENGINES

Reciprocating internal combustion engines (RICE) are used in a variety of applications, including gas compression, pumping, and power generation. RICE can either be: (1) spark-ignited and fueled by natural gas, propane, or gasoline; or (2) compression-ignited and fueled by diesel. Spark-ignition engines fueled by natural gas, propane, and gasoline can operate lean (i.e., with a higher air-to-fuel ratio) or rich (i.e., with a lower air-to-fuel ratio). Compression-ignition diesel-fueled engines operate lean. A rich-burn engine operates with excess fuel during combustion, whereas a lean-burn engine operates with excess air.

Natural gas-fired RICE are the focus of this section and are used throughout the oil and gas industry, as described by EPA:

> Most natural gas-fired reciprocating engines are used in the natural gas industry at pipeline compressor and storage stations and at gas processing plants. These engines are used to provide mechanical shaft power for compressors and pumps. At pipeline compressor stations, engines are used to help move natural gas from station to station. At storage facilities, they are used to help inject the natural gas into high pressure natural gas storage fields. At processing plants, these engines are used to transmit fuel within a facility and for process compression needs (e.g., refrigeration cycles). The size of these engines ranges from 50 brake horsepower (bhp) to 11,000 bhp. In addition, some engines in service are 50–60 years old and consequently have significant differences in design compared to newer engines, resulting in differences in emissions and the ability to be retrofitted with new parts or controls.
>
> At pipeline compressor stations, reciprocating engines are used to power reciprocating compressors that move compressed natural gas (500–2000 [pounds per square inch gauge (psig)]) in a pipeline. These stations are spaced approximately 50 to 100 miles apart along a pipeline that stretches from a gas supply area to the market area. The reciprocating compressors raise the discharge pressure of the gas in the pipeline to overcome the effect of frictional losses in the pipeline upstream of the station, in order to maintain the required

> suction pressure at the next station downstream or at various downstream delivery points. The volume of gas flowing and the amount of subsequent frictional losses in a pipeline are heavily dependent on the market conditions that vary with weather and industrial activity, causing wide pressure variations. The number of engines operating at a station, the speed of an individual engine, and the amount of individual engine horsepower (load) needed to compress the natural gas is dependent on the pressure of the compressed gas received by the station, the desired discharge pressure of the gas, and the amount of gas flowing in the pipeline. Reciprocating compressors have a wider operating bandwidth than centrifugal compressors, providing increased flexibility in varying flow conditions. Centrifugal compressors powered by natural gas turbines are also used in some stations and are discussed in another section of this document.[12]

Natural gas-fired reciprocating engines are also used at well sites across the oil and gas industry in various applications including, e.g., reciprocating compressors and pump engines used to lift oil out of a well.

Natural gas-fired RICE can be classified as two-stroke or four-stroke engines. In a two-stroke engine, the power cycle occurs in a single crankshaft revolution and two strokes: an intake/compression stroke; and a power/exhaust stroke. In a four-stroke engine, the power cycle is completed with two crankshaft revolutions and four strokes: an intake stroke; compression stroke; power stroke; and exhaust stroke. Natural gas-fired RICE units encompass three engine types or classes:

1. Two-stroke lean-burn (2SLB)
2. Four-stroke lean-burn (4SLB)
3. Four-stroke rich-burn (4SRB)

NOx emissions from RICE are highly dependent on combustion temperature, with higher temperatures resulting in more NOx emissions. Rich-burn engines operate with an air-to-fuel ratio (A/F) that is rich with fuel resulting in higher fuel use, increased combustion temperatures, increased engine power, and decreased engine efficiency relative to a lean-burn engine. Lean-burn engines operate with an A/F that is lean with fuel resulting in less fuel use, decreased combustion temperatures, decreased engine power, and increased engine efficiency relative to a rich burn engine.

UNITS

NOx emissions from RICE are generally expressed as emission rates in grams per brake horsepower hour (g/bhp-hr) or as a concentration in parts per million by volume (ppmv or ppmvd). All concentrations expressed in ppmv are on a dry basis and corrected to 15% oxygen. Emission rates expressed in g/bhp-hr and grams per horsepower-hour (g/hp-hr) are assumed to be roughly equivalent for the RICE applications in this section. The following conversion factors from EPA's Updated Information on NOx Emissions and Control Techniques document* are used in this section:

[12] EPA, AP-42, Fifth Edition, Volume 1, Chapter 3: Stationary Internal Combustion Sources.

Uncontrolled rich-burn Spark-Ignition (SI) engines and rich-burn engines controlled with nonselective catalytic reduction (NSCR)……..67 ppmv = 1 g/bhp-hr Uncontrolled lean-burn engines, lean-burn engines controlled with selective catalytic reduction (SCR), and rich-burn engines controlled with prestratified charge™ (PSC) technology……73 ppmv = 1 g/bhp-hr Lean-burn engines controlled with Low Emission Combustion (LEC) Technology……..75 ppmv = 1 g/bhp-hr * EPA, Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques, September 2000 (EPA-457/R-00-001)

A. RICH-BURN RICE: COMBUSTION CONTROLS

Emission control technologies for RICE depend on the A/F and therefore different controls apply to different engine types. NOx emissions reductions from these engines can be achieved through combustion controls or through post-combustion (add-on) controls. The following retrofit combustion control technologies for rich-burn RICE are described by EPA in its *Alternative Control Techniques Document – NOx Emissions from Stationary Reciprocating Internal Combustion Engines*, and EPA's descriptions are reprinted below:[13]

Rich-Burn A/F Adjustments

> Adjusting the A/F toward fuel-rich operation reduces the oxygen available to combine with nitrogen, thereby inhibiting NOx formation. The low-oxygen environment also contributes to incomplete combustion, which results in lower combustion temperatures and, therefore, lower NOx formation rates. The incomplete combustion also increases [carbon monoxide (CO)] emissions and, to a lesser extent, [hydrocarbons (HC)] emissions. Combustion efficiency is also reduced, which increases brake-specific fuel consumption (BSFC). Excessively rich A/F's may result in combustion instability and unacceptable increases in CO emissions.
>
> The A/F can be adjusted on all new or existing rich-burn engines. Sustained NOx reduction with changes in ambient conditions and engine load, however, is best accomplished with an automatic A/F control system.
>
> The achievable NOx emission reduction ranges from approximately 10 to 40 percent from uncontrolled levels. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 9.5 to 14.0 g/hp-hr (640

[13] EPA-453/R-93-032 *Alternative Control Techniques Document – NOx Emissions from Stationary Reciprocating Internal Combustion Engines* (July 1993), *available at*: https://www3.epa.gov/airquality/ctg_act/199307_nox_epa453_r-93-032_internal_combustion_engines.pdf [hereinafter referred to as "EPA 1993 Alternative Control Techniques Document for RICE"].

> to 940 ppmv). Available data show that the achievable NOx reduction using A/F varies for each engine model and even among engines of the same model, which suggests that engine design and manufacturing tolerances influence the effect of A/F on NOx emission reductions.[14]

NOx Removal Efficiency:	*10-40%*
Controlled NOx Emission Rates:	*9.5 to 14.0 g/hp-hr*
	640 to 940 ppmv

Rich-Burn Ignition Timing Retard (IR)

> Ignition timing retard delays initiation of combustion to later in the power cycle, which increases the volume of the combustion chamber and reduces the residence time of the combustion products. This increased volume and reduced residence time offer the potential for reduced NOx formation. . . .
>
> Ignition timing can be adjusted on all new or existing rich-burn engines. Sustained NOx reduction with changes in ambient conditions and engine load, however, is best accomplished using an electronic ignition control system.
>
> The achievable NOx emission reduction ranges from virtually no reduction to as high as 40 percent. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 9.5 to 15.8 g/hp-hr (640 to 1,060 ppmv). Available data and information provided by engine manufacturers show that, like AF, the achievable NOx reductions using IR are engine-specific.[15]

NOx Removal Efficiency:	*0-40%*
Controlled NOx Emission Rates:	*9.5 to 15.8 g/hp-hr*
	640 to 1,060 ppmv

A/F adjustment and IR can be employed together to reduce NOx emissions from rich-burn RICE. According to EPA, the achievable emissions reductions are similar to that for A/F adjustments (i.e., 10-40%) but may offer the potential to minimize some of the adverse impacts of other operating parameters (e.g., CO emissions, engine response, fuel consumption).[16]

Limited cost data indicate that combustion controls for rich-burn RICE costs between $400 to $1,000 per ton of NOx reduced for engines greater than 500 horsepower (hp).[17]

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[14] *Id.* at 2-5.
[15] *Id.* at 2-5 and 2-9.
[16] *Id.* at 2-9.
[17] *Id.* at 2-30. *See also* California Air Resources Board (CARB) Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines, November 2001, Table V-2 at V-3, *available at*: https://ww3.arb.ca.gov/ractbarc/rb-iceall.pdf [hereinafter referred to as "CARB 2001 Guidance"]. The CARB cost effectiveness analysis assumes the engines are run at 100% load for 2,000 hours per year, annualized costs are figured based on an interest rate of 10% over a 10-year life.

B. RICH-BURN RICE: PRESTRATIFIED CHARGE (PSC)

Prestratified charge (PSC) is a combustion modification that converts rich-burn engines to lean-burn engines by retrofitting the air injectors to make a leaner A/F ratio. PSC is described by EPA in its Alternative Control Techniques Document for RICE, as follows:

> This add-on control technique facilitates combustion of a leaner A/F. The increased air content acts as a heat sink, reducing combustion temperatures, thereby reducing NOx formation rates. Because this control technique is installed upstream of the combustion process, PSC® is often used with engines fueled by sulfur-bearing gases or other gases (e.g. sewage or landfill gases) that may adversely affect some catalyst materials.
>
> Prestratified charge applies only to four-cycle, carbureted engines. Pre-engineered, "off-the-shelf" kits are available for most new or existing candidate engines, regardless of age or size. According to the vendor, PSC® to date has been installed on engines ranging in size up to approximately 2,000 hp.
>
> The vendor offers guaranteed controlled NOx emission levels of 2 g/hp-hr (140 ppmv), and available test data show numerous controlled levels of 1 to 2 g/hp-hr (70 to 140 ppmv). The extent to which NOx emissions can be reduced is determined by the extent to which the air content of the stratified charge can be increased without excessively compromising other operating parameters such as power output and CO and HC emissions. The leaner A/F effectively displaces a portion of the fuel with air, which may reduce power output from the engine. For naturally aspirated engines, the power reduction can be as high as 20 percent, according to the vendor. This power reduction can be at least partially offset by modifying an existing turbocharger or installing a turbocharger on naturally aspirated engines. In general, CO and HC emission levels increase with PSC®, but the degree of the increase is engine-specific. The effect on BSFC is a decrease for moderate controlled NOx emission levels (4 to 7 g/hp-hr, or 290 to 500 ppmv), but an increase for controlled NOx emission levels of 2 g/hp-hr (140 ppmv) or less.[18]

PSC NOx Removal Efficiency:	*87% (85-90%, EPA 2000)*[19]
Controlled NOx Emission Rates:	*2 g/hp-hr*
	140 ppmv

PSC NOx reduction efficiency depends on how much the air content can be increased without adversely affecting the performance of the engine; achieving lower NOx rates with PSC will result in sacrifices in engine power output. PSC, generally, can only achieve a NOx emission rate as low as 2 g/bhp-hr. EPA re-affirmed the limitations of PSC in its 2000 Updated Information on NOx Emissions and Control Techniques for RICE, stating:

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[18] EPA 1993 Alternative Control Techniques Document for RICE at 2-9 to 2-10.

[19] EPA-457/R-00-001 *Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques,* September 2000, *available at*: https://nepis.epa.gov/Exe/ZyPDF.cgi/P100V343.PDF?Dockey=P100V343.PDF [hereinafter referred to as "EPA 2000 Updated Information on NOx Emissions and Control Techniques"].

> The 1993 ACT document found that the achievable NOX emission level for PSC is 2.0 g/bhp-hr, based on the vendor's guarantees. This value is generally consistent with the information gathered for this project and is a representative value for the NOX emission level that can be achieved using PSC control technology.[20]

Limited cost data indicate that PSC achieving 80% NOx reduction efficiency costs between $200 to $800 per ton of NOx reduced for engines ranging in size from 50–1,500 hp.[21]

Even the best-case NOx emissions reductions for PSC are generally lower than the emissions reductions that can be accomplished with the nonselective catalytic reduction (NSCR) technologies discussed below. And NSCR also generally costs less, with capital and annual costs less than PSC for almost all engine sizes, according to data from EPA.[22] However, for fuels with higher sulfur content (e.g., waste gases), PSC technology can be effective at achieving NOx emissions reductions where higher sulfur fuels would adversely impact catalyst material used in post-combustion control technologies such as NSCR.

C. RICH-BURN RICE: NONSELECTIVE CATALYTIC REDUCTION (NSCR)

The use of NSCR technology began in the 1970s with the application of 3-way catalysts to gasoline-fueled motor vehicles in order to simultaneously control carbon monoxide, VOCs, and NOx emissions. In automobiles, the technology is known as a "catalytic convertor." Since then, NSCR has been widely applied to stationary engines. NSCR is usually also accompanied by an air/fuel ratio controller (AFRC), which is used to adjust the combustion parameters across the operating range of the engine in order to maintain the conditions needed for the efficient operation of the NSCR system (e.g., sufficient excess oxygen in the exhaust gas).

NSCR is described by EPA in its Alternative Control Techniques Document for RICE, as follows:

> Nonselective catalytic reduction is essentially the same catalytic reduction technique used in automobile applications and is also referred to as a three-way catalyst system because the catalyst reactor simultaneously reduces NO_X, CO, and HC to water (H_2O), carbon dioxide (CO_2), and diatomic nitrogen (N_2). The chemical stoichiometry requires that O_2 concentration levels be kept at or below approximately 0.5 percent, and most NSCR system require that the engine be operated at fuel-rich A/F's. . . .
>
> Nonselective catalytic reduction applies only to carbureted rich-burn engines and can be retrofit to existing installations. Sustained NOx reductions are achieved with changes in ambient conditions and operating loads only with an automatic A/F control system. . . .

[20] *Id.* at 4-21.

[21] *See* CARB 2001 Guidance at Table V-2 at V-3. The CARB cost effectiveness analysis assumes the engines are run at 100% load for 2,000 hours per year, annualized costs are figured based on an interest rate of 10% over a 10-year life.

[22] *See* EPA's 1993 Alternative Control Techniques Document for RICE Table 2-12 at 2-30.

> Catalyst vendors quote NOx emission reduction efficiencies of 90 to 98 percent. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 0.3 to 1.6 g/hp-hr (20 to 110 ppmv). . . .
>
> The predominant catalyst material used in NSCR applications is a platinum-based metal catalyst. The spent catalyst material is not considered hazardous, and most catalyst vendors accept return of the material, often with a salvage value that can be credited toward purchase of replacement catalyst.[23]

NSCR NOx Removal Efficiency:	*90-98%*
Controlled NOx Emission Rates:	*0.3 to 1.6 g/hp-hr*
	20 to 110 ppmv

According to EPA, when California air district standards were tightened to 96% NOx reduction and emission limits of 25 ppmv (0.37 g/bhp-hr), facilities shifted from PSC to NSCR to meet the standard.[24] This level of NOx control can be met with an NSCR retrofit to an existing unit. For example, retrofit installations of NSCR on five Caterpillar rich burn engines in Texas achieved a NOx reduction of 96% or greater on all of the engines.[25] On two of those engines, testing conducted after more than 4,000 hours of operation with NSCR indicated the NSCR controls were still achieving a 95% NOx reduction.[26] Employing NSCR to reduce NOx emissions from EPA's uncontrolled emission rate of 15.8 g/bhp-hr to 1.0 g/bhp-hr corresponds to a NOx emission reduction efficiency of 94%. Unless otherwise noted, the analyses provided further below in this section assume a 94% NOx reduction efficiency to meet a 1 g/bhp-hr emission rate. Lower NOx emission limits have been required by some states and local agencies that reflect a higher NOx removal efficiency (see Section II.G., below).

NSCR can effectively reduce CO, HC, VOCs (include formaldehyde), as well as NOx emissions, if properly optimized for control of all these pollutants. Such systems must control the A/F carefully to provide enough oxygen to ensure that CO and VOCs are oxidized but also limit oxygen enough to ensure the NOx is effectively reduced. The oxygen content of the exhaust gas needs to be within a narrow window to ensure effective control of all three pollutants, and thus an AFRC is necessary along with an oxygen sensor to provide feedback to the AFRC to ensure the proper fuel-rich operation.

HOURS OF OPERATION FOR RICE

Stationary RICE are used in a variety of applications throughout the oil and gas sector, from providing on-site power, driving pumps or compressors, and drilling operations at well sites to driving pipeline compressor stations to powering pumps, compressors, and refrigeration at gas processing plants. Because of the varying uses for RICE units, RICE units used in the oil and gas sector cover the full

[23] EPA 1993 Alternative Control Techniques Document for RICE at 2-10 to 2-11.
[24] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-19.
[25] OTC Technical *Information Oil and Gas Sector Significant Stationary Sources of NOx Emissions* October 17, 2012, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf at 45.
[26] *Id.*

range of operating schedules. In providing cost estimates herein, this report presents cost effectiveness analyses to reflect operating as few as 2,000 hours per year and as high as 8,000 hours per year. For example, compressor stations typically operate continuously, although not all compressor engines at a compressor station operate continuously. On the other hand, RICE units used for backup onsite electrical generation may not operate much at all in a year. Thus, a low-end operating capacity factor and a high-end capacity factor were assumed to reflect a range of costs across varying levels of operation.

A cost effectiveness analysis of NSCR was performed in 2010 for EPA, to help determine national impacts associated with EPA's final rule for Reciprocating Internal Combustion Engine National Emission Standards for Hazardous Air Pollutants (RICE NESHAP).[27] The analysis, performed by E^C/R Incorporated, was based on 2009 cost data for retrofitting NSCR on existing 4SLB engines from industry groups, vendors, and manufacturers of RICE control technology. E^C/R Incorporated performed a linear regression analysis[28] on the data set to determine the following linear equation for annual cost, which includes annual operating and maintenance costs plus annualized capital costs based on a 7% interest rate and 10-year life of controls:

NSCR Annual Cost = $4.77 x (hp) + $5,697 (2009$)

The capital cost equation for retrofitting an AFRC and NSCR on a 4SRB engine was determined by E^C/R Incorporated to be, as follows:

NSCR Capital Cost = $24.9 x (hp) + $13,118 (2009$)

These relationships are derived from a data set that includes engines ranging in size from 50–3,000 hp.

The E^C/R document does not explain why it assumed a 10-year life of controls for estimating the annualized capital costs. The life of a RICE unit is generally much longer than ten years, and is often at least thirty years.[29] The assumed 10-year life was not based on the catalyst replacement timeframe, because the E^C/R operating costs took into account the cost for replacing the catalyst every three years, as well as replacing the thermocouple every 7.5 years, the crankcase filters every three months, the oxygen sensor on a quarterly basis, and rotating the catalyst for cleaning annually.[30] Thus, the assumed 10-year life of an NSCR system seems arbitrary. In cost analyses done in 2000 for EPA, an equipment life of NSCR of fifteen years was assumed.[31] The state of Colorado also recently assumed a 15-year life of

[27] Memo from E^C/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010), *available at*: https://www.epa.gov/sites/production/files/2014-02/documents/5_2011_ctrlcostmemo_exist_si.pdf.

[28] *Id.* The report notes that the linear equation has a correlation coefficient (R) of 0.7987, concluding that it "shows an acceptable representation of cost data."

[29] *See, e.g.*, EPRI, 20 Power Companies Examine the Role of Reciprocating Internal Combustion Engines for the Grid, *available at*: https://eprijournal.com/start-your-engines/. The authors also note that, in reviewing permits for gas processing facilities and compressor stations in New Mexico, it is not uncommon to have engines that were constructed from the 1950's to 1970's still operating at such facilities.

[30] Memo from E^C/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010), at 4 and at 11, 13, and 15.

[31] *See* August 11, 2000, E.H. Pechan & Associates, Inc., NOx Emissions Control Costs for Stationary Reciprocating Internal Combustion Engines in the NOx SIP Call States, at 5 and at A-2, *available at*: https://www3.epa.gov/ttn/ecas/regdata/cost/pechan8-11.pdf. *See also* EPA, Regulatory Impact Analysis for the NOx SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).

NSCR for RICE units.[32] Given that EPA assumed a selective catalytic reduction (SCR) system at an industrial fossil fuel-fired boiler has a life of 20-25 years,[33] it seems very likely that NSCR would have a useful life of at least fifteen years if not longer. For the purpose of the NSCR cost analyses presented herein, a 15-year life of the NSCR system was assumed.

In addition, a lower interest rate than 7% is assumed in determining annualized costs of controls for this report, to be consistent with EPA's Control Cost Manual which recommends the use of the bank prime interest rate.[34] The bank prime rate fluctuates over time, and the highest it has been in the past five years is 5.5%.[35] In its cost calculation spreadsheet for SCR provided with its Control Cost Manual, EPA also used an interest rate of 5.5%.[36] Thus, a 5.5% interest rate has been used for the revised cost calculations presented herein.

Table 2 shows the cost effectiveness of NSCR and an AFRC achieving 94% NOx reduction efficiency and operating at 2,000 hours per year and 8,000 hours per year, based on these cost equations from EPA's 2010 RICE NESHAP, adjusted to reflect a 5.5% interest rate and 15-year life of controls.

Note that lower NOx emission limits have been required by some states and local agencies that reflect a higher NOx removal efficiency than the 94% assumed in the table below (see Section II.G.) and the costs of employing NSCR to meet these lower limits will be even more cost effective than what is shown here.

[32] *See* Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for RICE Source Category, circa 2008 [hereinafter referred to as "CDPHE RP for RICE"], at 8, *available at*: https://www.colorado.gov/pacific/sites/default/files/AP_PO_Reciprocating-Internal-Combustion-Engine-RICE-engines_0.pdf.

[33] *See* EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 80, *available at*: https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.

[34] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, *available at*: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

[35] *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.

[36] *Available at:* https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

Table 2. Cost Effectiveness to Reduce NOx Emissions from Rich-Burn RICE with NSCR and an AFRC, Based on EPA RICE NESHAP Cost Equations for Existing Stationary Spark-Ignition (SI) Engines[37]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF NSCR AND AFRC, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2009$
RICH-BURN	50	$5,303	$3,251/ton	$813/ton
	200	$5,859	$898/ton	$224/ton
	500	$6,971	$427/ton	$107/ton
	1,000	$8,824	$270/ton	$68/ton
	2,500	$14,382	$176/ton	$44/ton

TABLE NOTES:

- Cost data are assumed to be in 2009$, based on E^C/R Incorporated analysis of vendor and industry group data for engines ranging from 50–3,000 hp (EPA RICE NESHAP, 2010).
- Recalculated for 15-year life of controls and 5.5% interest rate.
- Assumes 94% NOx removal efficiency.

Colorado requires emissions from rich-burn RICE greater than 500 hp be controlled using NSCR with an AFCR. This requirement applies statewide to engines for which control costs are below $5,000 per ton of NOx reduced.[38] In its initial regional haze plan, Colorado completed a Reasonable Progress Evaluation for the RICE Stationary Source Category, including a NOx emission 4-Factor analysis for reasonable progress toward the national visibility goal.[39] In its evaluation, Colorado reported that, "[f]ew of the statewide rich burn RICE demonstrated control costs exceeding the $5,000 cost off-ramp. Consequently, the state concluded that such NSCR controls are installed on the majority of rich burn RICE over 500 HP statewide."[40] Colorado further reports that "[n]one of the operators of rich burn RICE outside the [Denver] metro-area ozone non-attainment area submitted information demonstrating control costs in excess of $5,000 per ton cost threshold, consequently, the majority of natural-gas fired RB RICE over 500 HP must operate an NSCR with an AFR controller."[41]

Colorado's Reasonable Progress Evaluation for RICE listed the capital and annual operating costs for retrofitting existing engines with NSCR and an AFCR, which are reiterated in Table 3.

[37] *See* Memo from E^C/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010). Annualized costs of control were calculated using a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and a 94% NOx removal efficiency.
[38] Colorado Regulation Number 7, *see* Section XVII.E.3.a.
[39] CDPHE RP for RICE.
[40] *Id.* at 4.
[41] *Id.* at 8.

Table 3. Capital and Operating Costs of NSCR with AFCR[42]

SOURCE CATEGORY	CAPITAL COSTS, 2003$*	ANNUAL OPERATING AND MAINTENANCE COSTS, 2003$*
RICH-BURN RICE > 500 hp	$35,000	$6,000
TABLE NOTES: *Colorado's cost estimates are from its "Denver Early Action Compact Analysis of Stationary Sources," dated 2003. Colorado does not specify, but it is assumed the cost data are from the 2003 timeframe.		

Colorado determined the annualized costs of control assuming a 15-year life of controls and indicating that, "[g]enerally the operational life of a catalyst is approximately 5 to 15 years, depending on factors such as how it is maintained and the particular duty cycle of the engine."[43] Colorado's use of a 15-year life of controls is also consistent with previous EPA analysis.[44] The annualized capital cost in Colorado's analysis of $4,851 appears to assume roughly a 10% interest rate, with total annualized costs – i.e., annualized capital costs plus annual operating and maintenance costs – of $10,851.[45] To be consistent with EPA's Control Cost Manual, which recommends the use of the bank prime interest rate, a lower interest rate than 10% is assumed in determining annualized costs of controls for this report.[46] As previously discussed, it is more appropriate to use a lower interest rate of 5.5%.[47] Thus, the cost data were revised to be consistent with the EPA's Control Cost Manual in assuming a 5.5% interest rate in amortizing the capital costs. [48]

Colorado presented the cost effectiveness of retrofitting RICE greater than or equal to 500 hp with NSCR and an AFCR based on 2008 NOx emissions reductions for 305 RICE units located outside the nonattainment area of the state. However, the more generalized approach used in this report of assuming 94% control effectiveness is consistent with Colorado's requirement that these engines – controlled with NSCR and an AFCR – meet an emission limit of 1 g/hp-hr.[49] Again, using EPA's uncontrolled emission rate of 15.8 g/bhp-hr, the NOx emissions reduction efficiency of meeting a 1 g/hp-hr NOx limit for these engines is approximately 94%.[50]

The following table shows the cost effectiveness of a 500 hp RICE unit operating at 2,000 hours per year and at 8,000 hours per year and employing NSCR and an AFRC to meet a 1 g/hp-hr NO_x limit, based on a 15-year life and 5.5% interest rate.

[42] *Id.*
[43] *Id.* at 10.
[44] EPA, Regulatory Impact Analysis for the NOx SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).
[45] CDPHE RP for RICE at 8.
[46] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.
[47] *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.
[48] *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.
[49] *See* Colorado Regulation Number 7, *see* Section XVII.E.2.b.
[50] EPA 1993 Alternative Control Techniques Document for RICE.

Table 4. Cost Effectiveness to Reduce NOx Emissions from Rich-Burn RICE with NSCR and an AFRC To Meet a 1 g/hp-hr NO_x Limit [51]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF NSCR AND AFRC, 2003$	COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2003$	COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2003$
RICH-BURN	500	$9,487	$582/ton	$145/ton

TABLE NOTES:

- Cost data are assumed to be in 2003$, based on Colorado's Reasonable Progress Evaluation for the RICE Source Category.
- Analysis assumes 15-year life of controls and 5.5% interest rate.
- Analysis assumes 94% NOx removal efficiency.

NSCR for Smaller Rich-Burn RICE and Cyclically-Loaded RICE (< 500 hp)

California Air Districts have long been regulating NOx emissions from RICE, including engines smaller than 500 hp, and the California Air Resources Board (CARB) issued guidance to Air Districts in 2001 on the best available retrofit technologies for controlling NOx emissions from a broad range of stationary RICE.[52]

In the 1990s, when EPA first issued its Alternative Control Techniques document for stationary RICE, over 90% of all natural gas-fueled RICE were well pumps with an average size of 15 hp operating, on average, 3,500 hours per year.[53] Today, these smaller well pump engines likely make up a smaller share of nationwide RICE applications across the oil and gas industry, with continued growth in gas production and associated compression and processing applications. However, NOx emissions from these smaller pumping engines, on a regional scale, can be significant. For example, NOx emissions from artificial lifts (e.g., beam pumping used to push oil to the surface) in the New Mexico counties of the Permian Basin make up 13% of all NOx emissions.[54] The average rated horsepower of these engines is 21 hp and the magnitude of these NOx emissions – inventoried in 2014 – was close to 4,000 tons.

[51] *See* CDPHE RP for RICE. Annualized costs of control were calculated using a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and a 94% NOx removal efficiency.
[52] CARB 2001 Guidance.
[53] EPA 1993 Alternative Control Techniques Document for RICE Table 3-1 at 3-14.
[54] IWDW 2014 Oil and Gas Emissions Inventories, *available at:* http://views.cira.colostate.edu/wiki/wiki/9170/2014-oil-and-gas-emissions-inventories.

CARB's 2001 guidance discusses RICE units derated[55] to less than 50 hp, indicating that, "[o]ne of the largest categories of the derated engines are cyclically-loaded units used to drive reciprocating oil pumps."[56]

Two specific concerns with respect to the applicability of NSCR to certain types of smaller pump engines used in the oil and gas sector include: (1) the impact that moisture and sulfur in the fuel have on the catalyst; and (2) the impact that variable engine loading has on maintaining sufficient temperatures. Some fuel gases contain high amounts of moisture and sulfur which can result in damage to (deactivation of) the catalyst. The sulfur content of pipeline-quality natural gas is low but some oil field gases can contain high sulfur concentrations. And in applications where engines are periodically idle or where the load is cyclical, it can be more difficult to maintain an adequate exhaust gas temperature. For example, for an oil well pump, the engine may operate at load for a time-period lasting from several seconds to around 20 seconds, followed by an equal amount of time idle. These limitations can generally be minimized through design and maintenance activities, e.g., by treating the field gas to reduce the moisture and sulfur content, heating the catalyst to avoid deactivation, thermally insulating the exhaust pipe and catalyst to maintain a proper temperature, etc.[57]

CARB recognized that these characteristics (e.g., cyclic loads and variable fuel composition) would, "tend to discourage the use of catalysts with air-to-fuel controllers." But CARB specifically noted that, "a review of source test data in [CARB's 2001 Guidance] indicates that there have been instances where these engines have been successfully controlled in the past by cleaning up the field gas, and 'leaning-out' the engine or installing a catalyst in some cases."[58]

Specifically, cyclic engines that drive certain oil pumps (e.g., beam- or crank-balanced pumping engines) fueled by oil field gas operate in a way that may adversely impact the effectiveness of NSCR control. Following are specific pump engine types, as defined in Santa Barbara County Air Pollution Control District (APCD) Rule 333 Control of Emissions from Reciprocating Internal Combustion Engines:[59]

> "Air-balanced pumping engine" means a noncyclically-loaded engine powering a well pump, with the pump using compressed air in a cylinder under the front of the walking beam to offset the weight of the column of rods and fluid in the well, eliminating the need for counterweights.

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[55] CARB describes a derated engine as, "one in which the manufacturer's brake horsepower rating has been reduced through some device which restricts the engine's output." CARB 2001 Guidance at IV-1.
[56] *See* CARB 2001 Guidance at IV-1.
[57] *Id.*; *also see* South Coast Air Quality Management District Preliminary Draft Staff Report for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines (July 2019), D-4, *available at:* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1110.2/rule-1110-2-pdsr_07172019.pdf?sfvrsn=6.
[58] *See* CARB 2011 Guidance at IV-1.
[59] Santa Barbara County APCD Rule 333 CONTROL OF EMISSIONS FROM RECIPROCATING INTERNAL COMBUSTION ENGINES, 333.C at 333-2, *available at:* https://ww3.arb.ca.gov/drdb/sb/curhtml/r333.pdf.

"Beam-balanced pumping engine" means a cyclically-loaded engine powering a well pump, with the pump counterweight on the back end of the walking beam. The counterweight is moved mechanically without a cylinder supplying air pressure.

"Crank-balanced pumping engine" means a cyclically-loaded engine powering a well pump, with the pump counterweight attached to a gearbox which is attached to the walking beam with a pitman arm. The counterweight is moved mechanically, in a circular motion, without a cylinder supplying air pressure.

"Cyclically-loaded engine" means an engine that under normal operating conditions has an external load that varies by 40 percent or more of rated brake horsepower during any load cycle or is used to power a well reciprocating pump including beam-balanced or crank-balanced pumps. Engines powering air-balanced pumps are noncyclically-loaded engines.

In Santa Barbara County APCD, cyclic rich-burn engines (beam- and crank-balanced pump engines) greater than 50 hp are expected to meet a NOx limit of 300 ppmv, corrected to 15% oxygen, by adjusting the A/F mixture (to operate lean) and properly tuning and maintaining the engines; these engines are not required to install add-on NSCR control. However, according to CARB's guidance, cyclic rich-burn engines have met emission limits as low as 50 ppmv (< 1 g/bhp-hr) by "using NSCR or by leaning the air/fuel mixture in conjunction with treating the field gas to reduce moisture and sulfur content."[60] Specifically, the following engine test data demonstrate emission rates under 50 ppmv (corrected to 15% oxygen) for pump engines:

Table 5. Pump Engine Test Data[61]

CA AIR DISTRICT	ENGINE TYPE	ENGINE SIZE[62]	CONTROL TECHNOLOGY	# OF TESTS	NOx EMISSIONS [ppmv corrected to 15% oxygen]
Santa Barbara	Air-balanced oil pumps	195 hp	NSCR	18	2-14
Santa Barbara	Beam- and crank-balanced oil pumps	131 hp	Leaning of A/F mixture	4	12-35
Santa Barbara	Beam- and crank-balanced oil pumps	39-46 hp	Leaning of A/F mixture	16	8-28
Santa Barbara	Beam- and crank-balanced oil pumps	39-49 hp	Leaning of A/F mixture	18	7-33
Ventura	Beam- and air-balanced oil pumps	Not specified	NSCR	5	50

[60] *See* CARB 2001 Guidance at IV-5.

[61] *Id.*at IV-5 to IV-6.

[62] Oil pump engines, sometimes derated, are typically less than 50 hp, however there do appear to be some engines used for oil pumping applications that are larger, as shown in this table. And in addition, the underlying source test data in CARB's 2001 Guidance from Santa Barbara County and Ventura County also include a few data points for rich-burn engines less than 50 hp with NSCR, e.g., four 48 hp engines in Santa Barbara County with NSCR, and a 48 hp engine and 25 hp engine in Ventura County with catalyst control. *See* CARB 2001 Guidance Tables D-2 and D-3.

CA AIR DISTRICT	ENGINE TYPE	ENGINE SIZE[62]	CONTROL TECHNOLOGY	# OF TESTS	NOx EMISSIONS [ppmv corrected to 15% oxygen]
Ventura	Beam- and air-balanced oil pumps	Not specified	NSCR	3	25
TABLE NOTE: the field gas used in these engines was either naturally low in sulfur or treated to pipeline-quality natural gas					

CARB concluded that, "[b]ecause of the demonstrated success of meeting the 50 ppmv NOx limit for cyclic rich-burn engines fueled by low-sulfur or treated field gas, we recommend that the districts consider the cost effectiveness of field gas treatment and emission controls in setting limits for these engines on a site-specific basis."[63] Essentially, CARB guidance proposed considering in its cost effectiveness analysis, the additional cost of field gas treatment including the material and labor costs of piping the treated fuel from the gas processing unit to the engine.

As of January 1, 2017, the San Joaquin Valley Air Pollution Control District (SJVAPCD) requires emissions from rich-burn RICE meet the following NOx limits:

Table 6. NOx Emission Limits for All Rich-Burn Non-Agricultural Operations Engines Rated at > 50 bhp[64]

ENGINE TYPE		NOx LIMIT [ppmvd corrected to 15% O2]	EQUIVALENT NOx LIMIT Converted to g/bhp-hr
4SRB	Cyclic Loaded, Field Gas Fueled	50	0.7
	Limited Use	25	0.4
	All other	11	0.2
TABLE NOTES: Conversions to g/bhp-hr limits are based on: 67 ppmv = 1 g/bhp-hr (per EPA's 1993 Alternative Control Techniques Document, page 4-11)[65]			

SJVAPCD completed a cost effectiveness analysis for the second phase of its internal combustion engine rule (Rule 4702) in 2003.[66] The District analyzed a broad array of control scenarios to meet these NOx limits including installing NSCR on both cyclic and non-cyclic rich-burn RICE of wide-ranging power output and capacity utilization.

[63] *See* CARB 2001 Guidance at IV-6.
[64] SJVAPCD Rule 4702 Internal Combustion Engines, Tables 1 and 2, *available at*: https://www.valleyair.org/rules/currntrules/r4702.pdf.
[65] SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), at B-3, *available at*: https://ww3.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjvapcd_4702_report.pdf.
[66] *Id.*

SJVAPCD found that the costs to install and operate NSCR at cyclically-loaded RICE units to meet the limit in Table 6 above were cost effective, with costs ranging from $394/ton to $20,272/ton (1999$), which reflected costs of NSCR assuming a 10-year life and a 10% interest rate.[67]

To use more current data on NSCR costs applied to cyclically-loaded units, the E^c/R cost equations provided in Section II.C. above were used to estimate cost effectiveness for cyclically-loaded RICE units. As previously stated, the E^c/R cost equations take into account the addition of an AFRC as well as the costs of the NSCR. It was assumed that the NSCR system would achieve 90% control of NOx at cyclically-loaded engines as is required by the Santa Barbara emission limit.[68] To reflect varying levels of operation, emission reductions were based on operating 2,000 hours per year, 4,500 hours per year, and 8,000 hours per year. Texas Commission on Environmental Quality (TCEQ) data for artificial lifts operating in the Permian Basin indicates that such units operate 4,380 hours per year, although a much higher annual hours of operation of 7,106 has been assumed for artificial lift engines in the Greater San Juan Basin.[69] Thus, to give a range of cost effectiveness of NSCR at cyclically-loaded units, cost effectiveness of NSCR was determined for a low, medium, and high number of operating hours per year. As with other NSCR cost effectiveness analyses, a 15-year life and a 5.5% interest rate were assumed. The results of this cost effectiveness analyses are presented in Table 7.

[67] *Id.* at B-2 and at Table 3.
[68] Santa Barbara County APCD Rule 333 CONTROL OF EMISSIONS FROM RECIPROCATING INTERNAL COMBUSTION ENGINES, 333.C at 333-2.
[69] November 2016, RAMBOLL ENVIRON, San Juan and Permian Basin 2014 Oil and Gas Emission Inventory Inputs Final Report, at 25 and Appendix A at A-1, *available at*: https://www.wrapair2.org/pdf/2016-11y_Final%20GSJB-Permian%20EI%20Inputs%20Report%20(11-09).pdf.

Table 7. Cost Effectiveness to Reduce NOx Emissions from Rich-Burn Cyclically-Loaded RICE Units with NSCR and AFRC, Based on EPA RICE NESHAP Cost Equations for NSCR[70]

ENGINE TYPE	SIZE (hp)	ANNUALIZED COSTS OF NSCR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 4,500 HR/YR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2009$
RICH-BURN	50	$5,303	$3,383/ton	$1,504/ton	$846/ton
	75	$5,396	$2,295/ton	$1,020/ton	$574/ton
	100	$5,489	$1,751/ton	$778/ton	$438/ton
	250	$6,045	$771/ton	$343/ton	$193/ton
	500	$6,971	$445/ton	$198/ton	$111/ton

TABLE NOTES:

- Cost data are assumed to be in 2009$, based on E^C/R Incorporated analysis of vendor and industry group data (EPA RICE NESHAP, 2010).
- Recalculated for 15-year life of controls and 5.5% interest rate.
- Assumes 90% NOx removal efficiency.

CARB's 2001 Guidance and the cost effectiveness analysis in this section for RICE units smaller than 500 hp show that application of NSCR to engines less than 500 hp can be cost effective. For RICE units used in oil pumping applications CARB describes situations where NSCR has been applied to cyclic rich-burn RICE to meet limits as low as 50 ppmv, citing certain types of "grasshopper" oil well pumps in Santa Barbara County.[71] And for oil pumping RICE units less than 50 hp CARB identified electrification (discussed in Section II.F, below), in addition to A/F adjustments and catalytic control, as technically feasible approaches to reducing NOx emissions from engines of this size.[72]

Further, SJVAPCD Rule 4702 for Internal Combustion Engines has a provision for RICE units at least 25 bhp, up to, and including 50 bhp that requires units that are sold after July 2012 to meet the applicable requirements and emission limits of EPA's NSPS for spark-ignition internal combustion engines in 40 CFR Subpart Part 60, JJJJ, for the year in which the ownership of the engine changes.[73] In the response to comments on its NSPS Subpart JJJJ rulemaking,[74] EPA provides many examples of the successful application of NSCR on small rich-burn engines and variable-load engines (noted as pumpjack engines or

[70] *Id*. Annualized costs of control were calculated using a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and control efficiency of 90%.

[71] CARB 2001 Guidance at IV-5. "Source tests of NSCR-equipped cyclic engines in Santa Barbara County have shown that these engines can be effectively controlled with or without air/fuel controllers provided the oil well pumps are air-balanced units."

[72] CARB 2001 Guidance at II-1.

[73] SJVAPCD Rule 4702 Internal Combustion Engines Section 5.1

[74] 73 Fed. Reg. 3,568-3,614 (Jan. 18, 2008).

compressor engines) that justify its standards as achievable and demonstrated for very small rich-burn RICE.[75]

Application of NSCR to rich-burn RICE is cost effective for a wide range of engine sizes and types.

While the cost estimates and cost algorithms in this section are of a cost basis that is from the 1999–2009 timeframe, it is important to note that, from at least 2001, several state and local air agencies have found that the costs of control to achieve NOx emission limits of 1 g/bhp-hr (67 ppmvd) and even lower NOx emission limits were cost effective to require such a level of control on existing rich-burn RICE. This will be discussed further in Section II.G. below. It is not possible to accurately escalate these costs to 2019 dollars. The Chemical Engineering Plant Cost Index (CEPCI) has been used extensively by EPA for escalating costs, but EPA states that using the CEPCI indices to escalate costs over a period longer than five years can lead to inaccuracies in price estimation.[76] Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. As an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc.

The environmental and energy impacts of NSCR for rich-burn RICE include the following:

- 0 to 5% increase in fuel consumption resulting in increased CO_2 emissions[77]
- 1 to 2% reduction in power output[78]
- Increased solid waste disposal from spent catalysts.[79]

The impacts on increased fuel consumption and increased solid waste disposal are taken into account in the cost effectiveness analysis. Further, NSCR has been installed extensively on RICE units in the United States, and these non-air quality environmental and energy impacts are not generally considered to be impediments to implementing the control.

NSCR can be installed fairly quickly. The Institute of Clean Air Companies indicates that "off-the-shelf" NSCR converters can be installed in six to eight weeks. For NSCR installations that are more site-specific, NSCR can be installed in approximately fourteen weeks.[80]

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[75] *See* EPA's Response to Public Comments on Spark-Ignition (SI) New Source Performance Standards (NSPS)/National Emission Standards for Hazardous Air Pollutants (NESHAP), posted to EPA's docket on January 2, 2008, Docket ID EPA-HQ-OAR-2005-0030-0249, at 95-100, *available at*: https://www.regulations.gov/document?D=EPA-HQ-OAR-2005-0030-0249.

[76] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.

[77] *See* EPA 1993 Alternative Control Techniques Document for RICE Table 3-1 at 3-14.

[78] *Id.* Table 2-4 at 2-8.

[79] CDPHE RP for RICE at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, EPA, Office of Air Quality Planning and Standards, RTP).

[80] Institute of Clean Air Companies, Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources, December 4, 2006 at 9, *available at:* https://cdn.ymaws.com/www.icac.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.

D. LEAN-BURN RICE: LOW EMISSION COMBUSTION (LEC)

Low emission combustion (LEC) retrofit kits are designed to achieve extremely lean A/F in order to minimize NOx emissions. The various retrofit technologies can include:

- Redesign of cylinder head and pistons to improve mixing (on smaller engines)
- Precombustion chamber (on larger engines)
- Turbocharger
- High energy ignition system
- Aftercooler
- AFRC[81]

According to EPA, "[n]ew spark-ignition engines equipped with LEC technology are, by definition, lean-burn engines."[82] A wide range of emission rates are achievable with LEC technology, with emissions generally no higher than 2 g/hp-hr and often significantly lower. EPA's updated information on stationary RICE NOx emissions and control technologies concludes, for lean-burn engines, an emission rate of 2.0 g/bhp-hr is achievable for "new engines and most engines retrofitted with LEC technology."[83] LEC is described by EPA in its Alternative Control Techniques Document, as follows:

> Low-emission combustion designs are available from engine manufacturers for most new SI engines, and retrofit kits are available for some existing engine models. For existing engines, the modifications required for retrofit are similar to a major engine overhaul, and include a turbocharger addition or upgrade and new intake manifolds, cylinder heads, pistons, and ignition system. The intake air and exhaust systems must also be modified or replaced due to the increased air flow requirements.
>
> Controlled NOx emission levels reported by manufacturers for [LEC] are generally in the 2 g/hp-hr (140 ppm) range, although lower levels may be quoted on a case-by-case basis. Emission test reports show controlled emission levels ranging from 1.0 to 2.0 g/hp-hr (70 to 140 ppmv). Information provided by manufacturers shows that, in general, BSFC decreases slightly for [LEC] compared to rich-burn designs, although in some engines the BSFC increases. An engine's response to increases in load is adversely affected by [LEC], which may make this control technique unsuitable for some installations, such as stand-alone power generation applications. The effect on CO and HC emissions is a slight increase in most engine designs.[84]

LEC NOx Removal Efficiency:	*87%*
Controlled NOx Emission Rates:	*1-2 g/hp-hr*
	70 to 140 ppmv

[81] EPA, Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500-0508, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance, August 2016, Appendix A at 5-3, *available at:* https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0500-0508 [hereinafter referred to as "2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls"].
[82] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-3.
[83] *Id.* at 4-12.
[84] EPA 1993 Alternative Control Techniques Document for RICE.

In its Updated Information on NOx Emissions and Control Techniques Document for RICE, EPA states the following test data for LEC:

> In all, the sources of NOx emission test data [] include the results of 476 individual tests conducted on 58 engines. (This count does not include the aggregated data in some of the sources discussed [], such as the May 2000 EPA memo and the AP-42 sections.) In these tests, NOx emissions ranged from 0.1 g/bhp-hr to 4.8 g/bhp-hr. Ninety-seven percent of these tests (460) found emissions less than or equal to 2 g/bhp-hr. Almost 75 percent (356) of the tests found emissions less than or equal to 1 g/bhp-hr, and 25 percent (120) found emissions of less than or equal to 0.5 g/bhp-hr. Only two tests measured NOx emissions greater than or equal to 4 g/bhp-hr.[85]

EPA also indicates that, "LEC is expected to be the most common control method for meeting the [1991 CARB Best Available Retrofit Control Technology (BARCT) for Stationary IC Engines], although SCR may be used as an alternative if LEC is unsuitable for a particular model engine."[86]

And according to the Interstate Natural Gas Association of America (INGAA), "LEC is the preferred approach to reduce lean-burn engine NOx emissions, but EPA or states may consider additional controls such as selective catalytic reduction (SCR)."[87]

EPA further states in its Updated Information on NOx Emissions and Control Techniques for RICE:

> Low-emission combustion retrofit equipment and services are generally available, particularly for the most plentiful engine models. Cooper Energy Services, maker of Cooper-Bessemer, Ajax, Superior, and Delaval engines provides CleanBurn™ retrofits for all of its larger models and offers these services for engines manufactured by other companies, as well. Dresser-Rand, manufacturer of Ingersoll-Rand, Clark, and Worthington engines also offers retrofit services for its lean-burn engines. The Waukesha Engine Division of Dresser Industries manufactures two engine families that are available either in rich-burn or LEC configurations. The company offers LEC retrofit services for those engines originally sold in the rich-burn configuration. At least three third-party vendors (Diesel Supply Company; Enginuity, Inc.; and Emissions Plus, Inc.) offer retrofit services for a wide variety of engine makes and models. These vendors will work with any model engine, although economies of scale can reduce capital costs for plentiful engines. For other engines, customized precombustion chambers can result in somewhat higher costs.[88]

[85] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-9.
[86] *Id.* at 4-11.
[87] INGAA, Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry (July 2014), *available at*: https://www.ingaa.org/File.aspx?id=22780.
[88] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-4.

California Air Districts have long been regulating NOx emissions from RICE, including lean-burn RICE. CARB issued guidance to Air Districts in 2001 on the reasonably available control technologies (RACT) and the best available retrofit control technologies (BARCT) for controlling NOx emissions from a broad range of stationary RICE.[89] In its analysis, CARB determined that LEC was a RACT level of control, and CARB set a NOx RACT limit of 125 ppmv.[90] CARB established a BARCT NOx limit for two- and four-stroke lean-burn engines rated at or higher than 100 hp of 65 ppmv or 90% reduction in NOx emissions.[91] CARB indicated that this lower NOx BARCT limit could also be met with LEC for many engines, although some engines might require some supplemental measures such as ignition system modifications and engine derating and others might require SCR to meet the BARCT NOx limit.[92] LEC can achieve 80 to 90% NOx reductions or even higher.[93]

The only exemptions CARB proposed from the NOx BARCT limit were for lean-burn engines rated less than 100 hp. With respect to these smaller engines, CARB determined that there are a relatively small number of such two-stroke lean-burn engines that cannot cost effectively install LEC or other NOx controls necessary to meet the NOx limits set for lean-burn RICE (both RACT and BARCT limits).[94] CARB described these engines as "located in gas fields statewide and [] used to drive compressors at gas wells."[95] CARB determined that, "the only cost effective way to control emissions from the[se] small two-stroke engines is by properly maintaining and tuning these engines which includes replacing oil-bath air filters with dry units and periodically cleaning the air/fuel mixer and muffler."[96] CARB ultimately recommend that the air districts, "require the replacement of these engines at the end of the two-stroke engine's useful life with prime movers having lower NOx emissions."[97]

CARB conducted cost effectiveness analyses for LEC on lean-burn RICE at a wide variety of engine power output ratings. CARB's analyses of capital and annual operating costs for retrofitting existing engines with LEC (and other NOx controls) were based on, "a mixture of quotes and extrapolations of cost from information provided by industry sources, associations, local governments, and the U. S. EPA."[98] CARB's cost data for LEC are presented in the table below.

[89] CARB 2001 Guidance.
[90] *Id.* at IV-6.
[91] *Id.* at IV.9.
[92] *Id.* at II-2, IV-10.
[93] EPA has said NOx reductions with LEC could be as high as 93%. *See* EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) at 5-67.
[94] *Id.* at II-2.
[95] *Id.* at IV-7.
[96] *Id.*
[97] *Id.*
[98] *Id*. at V-2.

Table 8. Capital Costs of LEC, 2001$[99]

POWER OUTPUT (hp)	LEC CAPITAL COSTS
50-150	$14,000
151-300	$24,000
301-500	$42,000
501-1,000	$63,000
1,001-1,500	$148,000

CARB calculated cost effectiveness for LEC assuming 80% NOx control, a 10-year life of the controls, and a 10% interest rate.[100] As previously discussed, to be consistent with EPA's Control Cost Manual which recommends the use of the bank prime interest rate, it is more appropriate to use a lower interest rate of 5.5%.[101] Thus, the CARB LEC cost data were revised to be consistent with the EPA's Control Cost Manual in assuming a 5.5% interest rate in amortizing the capital costs. It must be noted that CARB's assumed 10-year life of LEC controls seems unreasonably short, as EPA has assumed a 15-year life of all controls for stationary internal combustion engines in other cost analyses.[102] Thus, the CARB LEC cost data were revised to assume a 15-year life of LEC controls.

CARB's cost analysis also assumed that the engines are run at rated power (100% load) for only 2,000 hours annually, which is equivalent to a capacity factor of roughly 25%. To reflect the cost effectiveness values for a range of operating hours, CARB's cost analysis was revised to reflect costs at 91% capacity factor, or 8,000 operating hours per year.

Last, CARB's cost effectiveness analysis only assumed an 80% NOx removal efficiency with LEC. As discussed above, an 80% NOx control efficiency is the low-end of NOx removal rates that can be achieved with LEC at lean-burn engines. CARB's BARCT limit is based on 90% NOx reduction. Thus, CARB's cost analyses were also revised to include cost effectiveness for 90% NOx control as well as 80% NOx control. These revised cost effectiveness calculations—assuming a 5.5% interest rate, 15-year life of LEC, capacity factors of 2,000 operating hours and of 8,000 operating hours, and both 80% NOx control and 90% NOx control—are presented in Table 9 below.

[99] *Id.* Note that the cost basis is not identified, and it is assumed to be 2001 dollars based on the date of the analysis. Also note that for engines with power output of 1,001-1,500 hp, a mid-range cost of $148,000 was assumed, similar to the assumption made by EPA when using CARB's cost data in its 2016 CSAPR TSD.
[100] CARB 2001 Guidance at V-4.
[101] *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.
[102] EPA, Regulatory Impact Analysis for the NOx SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).

Table 9. Cost Effectiveness to Reduce NOx Emissions by 80%–90% from Lean-Burn RICE with LEC Operating at 2,000 and 8,000 Hours per Year[103]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF LEC, 2001$	COST EFFECTIVENESS OF LEC TO REDUCE NOx BY 80%–90%, 2,000 HOURS/YEAR, 2001$	COST EFFECTIVENESS OF LEC TO REDUCE NOx BY 80%–90%, 8,000 HOURS/YEAR, 2001$
LEAN-BURN	50	$1,857	$941/ton-$837/ton	$235/ton-$209/ton
	200	$3,184	$403/ton-$359/ton	$101/ton-$90/ton
	500	$5,572	$282/ton-$251/ton	$71/ton-$63/ton
	1,000	$8,358	$212/ton-$188/ton	$53/ton-$47/ton
	1,500	$19,635	$332/ton-$295/ton	$83/ton-$74/ton

The above analyses demonstrate that, with the exception of lean-burn engines rated at 50 hp that only operated 2,000 hours per year, the cost effectiveness of LEC at lean-burn engines is essentially between $80–$400/ton for a wide range of engine sizes and a wide range of operating hours.

In its Technical Support Document for Non-EGU NOx emissions for the CSAPR rule, EPA presented an equation for estimating the capital cost of LEC on natural gas lean-burn engines, based on cost calculations for engines of varying size and annual capacity factor from CARB's 2001 Guidance:[104]

$$\text{Capital cost} = \$16{,}019\ e^{0.0016 \times (hp)}$$

Thus, the above equation can be used to estimate capital costs for LEC based on the hp rating of the unit. CARB did not identify any operating expenses with LEC, and thus the appropriate capital recovery factor can be multiplied by the results of the equation above for any size lean-burn engine to estimate annual costs of control with LEC.

CARB's cost estimates for LEC are relatively consistent with EPA's prior cost analyses of LEC lean-burn engines. For example, EPA's 1993 Control Techniques Document for RICE found the cost effectiveness for medium-speed engines operating at a 91% capacity factor was in the range of $310–$590/ton (1993$, assuming a 7% interest rate and a 15-year life).[105] EPA subsequently updated the cost information on LEC technology for lean-burn SI engines because "developments in LEC technology have brought retrofit costs down in recent years."[106] Specifically, in EPA's Updated Information on NOx

[103] Cost information for LEC from CARB 2001 Guidance at Tables V-1 and V-2. Annualized cost of control assumed a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques for RICE (EPA-453/R-93-032).
[104] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 5-5. Note that the CSAPR TSD also presented an equation for annual costs, but it reflected annualized capital costs assuming a 7% interest rate and a 10-year life. Thus, the annualized cost equation is not provided here because it is not reflective of the current recommended interest rate for cost calculations of 5.5% or a 15-year life of controls.
[105] *See* EPA 1993 Alternative Control Techniques Document for RICE, Table 2-13 at 2-36.
[106] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-33.

Emissions and Control Techniques for RICE, its analysis of LEC retrofit for lean-burn SI engines showed, "cost effectiveness below $500 per ton of NOx reduced [in 1997$] for all engines larger than 2,000 bhp," which reflected an 80% capacity factor, 88% control, and a 7% interest rate. [107]

The 2001 CARB cost analyses for LEC is the most current comprehensive analyses for the costs of LEC available. It is recommended that the CARB cost data, as reflected in the equation given above (from EPA's CSAPR TSD), be used to calculate capital costs based on horsepower rating of an engine, assuming a 15-year life, 5.5% interest rate, and 90% NOx control. CARB's BARCT NOx limit of 125 ppmv should be considered as an achievable NOx emission limit with LEC at a lean-burn engine.

Application of LEC to lean-burn RICE is cost effective for a wide range of engine sizes and types.

While the cost estimates and cost algorithms in this section are of a cost basis that is close to twenty years old, it is important to note that, from at least 2001, several state and local air agencies have found that the costs of control to achieve NOx emission rates reflective of LEC at lean-burn engines (<2 g/bhp-hr (150 ppmv)) have been considered as cost effective to require such a level of control on existing lean-burn RICE over 100 hp. This will be discussed further in Section II.G. below. For the reasons previously discussed in this report, it is not possible to accurately escalate these costs from 2001 to a current dollar basis. Nonetheless, the fact that numerous state and local agencies have imposed NOx limits that reflect the application of LEC demonstrates that it is a control that has been extensively retrofitted to existing lean-burn engines.

The environmental and energy impacts of LEC for lean-burn RICE are minimal and include the following:

- A decrease in fuel consumption of 0 to 5% resulting in decreased CO_2 emissions, as well as a corresponding decrease in emissions of other air pollutants[108]
- No effect on power output.[109]

E. LEAN-BURN RICE: SELECTIVE CATALYTIC REDUCTION (SCR)

Selective catalytic reduction (SCR) is an add-on (post combustion) NOx reduction technology that has been in use as early as the 1970s and has been applied to numerous source categories including stationary RICE units. In its 1993 Alternative Control Techniques Document for Stationary RICE, EPA described SCR systems as follows:

> Selective catalytic reduction is an add-on control technique that injects ammonia (NH3) into the exhaust, which reacts with NOx to form N2 and H20 in the catalyst reactor. The two primary catalyst formulations are base-metal (usually vanadium pentoxide) and zeolite. Spent catalysts containing vanadium pentoxide may be considered a hazardous material in some areas, requiring special disposal considerations. Zeolite catalyst formulations do not contain hazardous materials.

[107] *Id.* at 5-9.
[108] *See* EPA 1993 Alternative Control Techniques Document for RICE, Table 2-7 at 2-15.
[109] *Id.*

> Selective catalytic reduction applies to all lean-burn SI engines and can be retrofit to existing installations except where physical space constraints may exist. There is limited operating experience to date, however, with these engines. A total of 23 SCR installations with lean-burn SI engines were identified in the United States from information provided by catalyst vendors, in addition to over 40 overseas installations. To date [1993] there is also little experience with SCR in variable load applications due to ammonia injection control limitations. Several vendors cite the availability of injection systems, however, designed to operate in variable load applications. Injection systems are available for either anhydrous or aqueous ammonia. As is the case for NSCR catalysts, fuels other than pipeline-quality natural gas may contain contaminants that mask or poison the catalyst, which can render the catalyst ineffective in reducing NOx emissions. Catalyst vendors typically guarantee a 90 percent NOx reduction efficiency for natural gas-fired applications, with an ammonia slip level of 10 ppm or less. One vendor offers a NOx reduction guarantee of 95 percent for gas- fired installations. Based on an average uncontrolled NOx emission level of 16.8 g/hp-hr (1,230 ppmv), the expected controlled NOx emission level is 1.7 g/hp-hr (125 ppmv). Emission test data show NOx reduction efficiencies of approximately 65 to 95 percent for existing installations. Ammonia slip levels were available only for a limited number of installations for manually adjusted ammonia injection control systems and ranged from 20 to 30 ppmv. Carbon monoxide and HC emission levels are not affected by implementing SCR. The engine BSFC increases slightly due to the backpressure on the engine caused by the catalyst reactor.[110]

There have been many advances in SCR systems and catalysts since EPA's 1993 Alternative Control Techniques Document. In 2012, the Ozone Transport Commission (OTC) issued a Technical Information Document on significant stationary sources of NOx emissions in the Oil and Gas Sector (hereinafter referred to as the "2012 OTC Report").[111] The OTC is a multi-state organization created under the CAA to address ozone problems in the Northeast and Mid-Atlantic U.S.[112] According to the 2012 OTC Report, many of the issues with variable load operation have been addressed by catalysts that have been designed to operate over a wide range of exhaust temperatures and for combustion devices with variable loads.[113] For example, in the 2012 OTC Report,[114] several vendors were listed that could provide such SCR systems and catalysts effective for the NOx control issues of lean-burn engines, such as Johnson Matthey,[115] Miratech Corporation which offers an SCR system for lean-burn engines used in natural gas compression,[116] CleanAir Systems which offers a lean-burn SCR called "E-Pod SCR" that is advertised to achieve up to 95% NOx reduction and reduce particulates, HC, and CO[117], and Caterpillar

[110] EPA 1993 Alternative Control Techniques Document for RICE.
[111] *See* Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf.
[112] *See* https://otcair.org/about.asp.
[113] *See* 2012 OTC Report at 25-26.
[114] *Id.* at 26-27.
[115] *See* https://matthey.com/en/products-and-services/emission-control-technologies/mobile-emissions-control/selective-catalytic-reaction.
[116] *See* https://www.miratechcorp.com/products/cbl/.
[117] *See* http://intermountainelectronics.com/uploads/media/Media_633929646982817973.pdf.

which offers SCR systems for several of its engines.[118] Although EPA's 1993 Alternative Control Techniques Document indicates achievable NOx emission rates of 1.7 g/hp-hr, the OTC identified NOx rates achievable with SCR at lean-burn engines of 0.2 to 1.0 g/bhp-hr, with the lower NOx rates achievable at four-stroke lean-burn engines and/or engines that also have some combustion control upgrades.[119] Moreover, two air districts in California—South Coast Air Quality Management District (SCAQMD) and SJVAPCD—have adopted NOx emission limits of 11 ppmv, which equates to 0.15 g/hp-hr, for lean-burn engines.[120] Based on this more recent information, the NOx reduction efficiency and achievable NOx emission rates are:

- *NOx Removal Efficiency:* *90-95+%*
- *Controlled NOx Emission Rates:* *0.15 to 1.0 g/hp-hr (11 to 73 ppmv)*

SCR can be applied to lean-burn spark-ignition engines, diesel compression-ignition engines, and dual-fuel compression-ignition engines. And while diesel engines are the most prevalent applications of SCR at RICE units, SCR has also been applied at lean-burn spark-ignition engines fired with natural gas, including at natural gas pipeline compressor stations.[121] Outside of the U.S., EPA stated in its 2000 update that "there are over 700 IC engines controlled with SCR systems in Europe and Japan, including approximately 80 to 100 2-stroke engines."[122] Thus, for those engines for which effective LEC retrofits are not available, SCR is available to achieve high levels of NOx control.

As previously stated, CARB issued guidance to California Air Districts in 2001 on the best available retrofit technologies for controlling NOx emissions from a broad range of stationary RICE.[123] For two- and four-stroke lean-burn engines greater than 100 hp, CARB set a BARCT limit 65 ppmv or 90% reduction in NO_x emissions.[124] CARB indicated that "[i]t is expected that the most common control method used to meet the BARCT emission limit [] will be the retrofit of low-emission combustion controls. Other techniques may also be used to supplement these retrofits, such as ignition system modifications and engine derating. For engines that do not have low-emission combustion modification

[118] *See* https://www.cat.com/en_GB/search/search-results.html?search=selective+catalytic+reduction&pagePath=%252Fcontent%252Fcatdotcom%252Fen_GB%252Fproducts%252Fnew%252Fpower-systems%252Foil-and-gas.
[119] *See* 2012 OTC Report at 27-28 and 40-41.
[120] *See* SQAQMD Rule 1110.2, Table I and SJVAPCD Rule 4702, Table 2. The SCAQMD 11 ppmv limit applies to engines at facilities that are not in the Regional Clean Air Incentives Market (RECLAIM) as of January 5, 2018, and SCAQMD has indicated there are 18 engines currently meeting the 11 ppmv limit. *See* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1110.2/par1110-2-wg2-final.pdf?sfvrsn=6 at Slide 32. The SJVAPCD 11 ppmv limit does not apply to lean-burn engines used for gas compression, or those engines of limited use operation (less than 4,000 hours per year), or those engines that are waste gas-fuel—a higher limit of 65 ppmv applies to these engines.
[121] *See, e.g.,* EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-13.
[122] *Id.* at 4-13 (EPA notes, "[f]rom the context, we believe that the source of this last data meant 2-stroke lean-burn SI engines fired with natural gas, although it is not explicit in the reference.").
[123] *See* CARB 2001 Guidance.
[124] *Id.*

kits available, SCR may be used as an alternative to achieve the BARCT emission limits."[125] Thus, CARB envisioned that some RICE units would need to install SCR.

The SJVAPCD requires that emissions from lean-burn RICE meet the following NOx limits:

Table 10. SJVAPCD NOx Emission Limits for All Lean-Burn Non-Agricultural Operations Engines[126]

ENGINE TYPE		**NOx LIMIT [ppmvd corrected to 15% O2]**	**EQUIVALENT NOx LIMIT [g/bhp-hr]**
2SLB	Gaseous Fueled; >50 hp and <100 hp	75	1.0
4SLB	Limited Use	65	0.9
	Used for gas compression	65 or 93% reduction	0.9
	All other	11	0.15

TABLE NOTES:

- Conversions to g/bhp-hr limits are based on EPA's Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques (September 2000), where the conversion for uncontrolled lean-burn engines and lean-burn engines controlled with SCR is: 73 ppmv = 1 g/bhp-hr

The 11 ppmv limit is clearly more stringent than CARB's recommended BARCT limit and thus presumably requires SCR to achieve at lean-burn RICE, possibly along with combustion modifications. SCAQMD adopted an 11 ppmv NOx limit for all RICE units unless located at a Regional Clean Air Incentives Market (RECLAIM) Facility, and thus SCAQMD has applied this lower NOx limit more broadly than the SJVAPCD.

The SJVAPCD completed a cost effectiveness analysis for the emission limits in the above table in 2003.[127] The District analyzed a broad array of control scenarios including installing SCR on lean-burn RICE of wide-ranging power output and capacity utilization and multiple applications (e.g., limited use, gas compression, etc.). SJVAPCD's report indicated that "[d]istrict staff feels that the annual compliance costs are reasonable for [all] five cases analyzed [including installation of a SCR system for a lean-burn engine]."[128] The report further concluded that "[a]lthough a few of the results indicated a high cost effectiveness, such results are due to the low emission reductions and not from high annual costs."[129]

SJVAPCD used the capital and annual operating costs for retrofitting existing engines with SCR based on CARB's 2001 guidance—which are based on installation of the more advanced parametric emissions

[125] *Id.*
[126] SJVAPCD Rule 4702 Internal Combustion Engines, *available at*: https://www.valleyair.org/rules/currntrules/r4702.pdf.
[127] SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), *available at*: https://ww3.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjvapcd_4702_report.pdf.
[128] *Id.* at B-2.
[129] *Id.*

monitoring systems (PEMS) feedforward system controls, the use of urea as the reducing agent, and a catalyst sized to achieve 96% reduction in NOx emissions—as presented in the table below.

Table 11. Capital and Operating Costs of SCR[130]

POWER OUTPUT (hp)	INSTALLED SCR CAPITAL COSTS, 1999$	ANNUAL OPERATING AND MAINTENANCE COSTS, 1999$
50	$45,000	$20,102
200	$45,000	$26,102
500	$60,000	$35,102
1,000	$149,000	$78,102
1,500	$185,000	$117,102

TABLE NOTES:

- The cost for the SCR is based on urea injection, with PEMS, and catalyst sized for 96% NOx conversion.

SJVAPCD determined the annualized costs of control assuming a 10-year life of controls and a 10% interest rate.[131] As previously discussed, to be consistent with EPA's Control Cost Manual, a lower interest rate of 5.5% should be used for current cost effectiveness calculations.[132] With respect to the SCR equipment life, SCR systems can likely last much longer than 15 years. EPA states that SCRs at boilers, refineries, industrial boilers, etc. have a useful life of 20-30 years.[133] To be consistent with EPA's statements on SCR, this report will assume a 20-year life for SCRs at lean-burn engines. Thus, a 5.5% interest rate and 20-year life of controls has been used for the revised SCR cost calculations presented herein.

SJVAPCD presented the cost effectiveness of retrofitting RICE with SCR based on reducing NOx emissions from a NOx rate of 740 ppmv to the proposed (and ultimately adopted) emission limit of 65 ppmv, which reflects a 91% control efficiency across the SCR. For RICE not already meeting NOx limits of 740 ppmv, employing SCR to reduce NOx emissions from what EPA considers to be the uncontrolled NOx emission rate of 1,230 ppmv (16.8 g/bhp-hr) to 65 ppmv corresponds to a NOx emissions reduction efficiency of 95%.[134] Such removal rates are achievable with SCR at lean-burn RICE, as discussed above.[135] However, the lower NOx rate of 11 ppmv that SJVAPCD has adopted for lean-burn engines not

[130] *Id.* Table 5.
[131] *Id.* Table 2 and 3.
[132] EPA's Control Cost Manual recommends the prime lending rate be used to amortize capital costs, and the highest the bank prime rate has been in the past five years is 5.5%. *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.
[133] *See* EPA's Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80.
[134] EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.
[135] *See*, *e.g.*, 2012 OTC Rep at 19.

used for compression and not operated at limited use (less than 4,000 hours per year) would also be achievable with SCR alone or with combustion controls plus SCR. A NOx limit of 11 ppmv reflects 99% control from uncontrolled levels.

SJVAPCD claimed to present cost effectiveness data for two different operating capacity factors: 25% and 75%. However, SJVAPCD also cited to CARB's cost analyses as the basis for SJVAPCD's assumed costs.[136] In the underlying cost effectiveness analysis, CARB assumed that the engines are run at rated power (100% load) for 2,000 hours annually, which is equivalent to a capacity factor of roughly 23%. It does not appear that SJVAPCD accounted for increased operating costs in its evaluation of costs at the higher capacity factor. Operating expenses at higher operating capacity factors would increase approximately by the ratio of the higher capacity factor (or operating hours) to the originally assumed capacity factor (or operating hours) in the original cost analysis.[137] The following table shows the cost effectiveness of retrofitting SCR to an uncontrolled lean-burn RICE operating at 2,000 hours per year and at 8,000 hours per year and meeting a 65 ppmv NO_x limit, based on a 20-year life and 5.5% interest rate. For the cost analyses shown in Table 12, SJVAPCD's operational costs were increased by a factor of four to more accurately reflect operational expenses at an operating capacity of 8,000 hours per year.

Table 12. Cost Effectiveness to Reduce NOx Emissions by 95% from 4SLB RICE with SCR Operating at 2,000 and 8,000 Hours per Year[138]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF SCR, 1999$	COST EFFECTIVENESS OF SCR, 2,000 HOURS PER YEAR, 1999$	COST EFFECTIVENESS OF SCR, 8,000 HOURS PER YEAR, 1999$
4SLB	50	$24,585	$13,567/ton	$3,392/ton
	200	$30,585	$4,244/ton	$1,061/ton
	500	$41,080	$2,281/ton	$570/ton
	1,000	$92,946	$2,574/ton	$644/ton
	1,500	$135,533	$2,512/ton	$628/ton

As previously stated, the cost effectiveness presented in Table 12 above reflects compliance with the 65 ppmv NOx emission limit with SCR, which corresponds to a NOx emissions reduction efficiency of

[136] *See* SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), Table 5, notes F and H.

[137] This is based on an analysis of varying hours of operation in EPA's SCR Cost Calculation Spreadsheet (06/2019) available on its Control Cost Manual website at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution. While this spreadsheet is designed to estimate costs of SCR for fossil fuel-fired boilers, it can be used to estimate the increased in operational costs with increases in operating hours for any SCR system given that the SCR components are the same whether for a gas-fired boiler or a gas-fired RICE unit.

[138] *See* SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), Table 5. Annualized costs of control were calculated using a capital recovery factor of 0.083679 (assuming a 20-year life of controls and a 5.5% interest rate). NOx emission reductions are based on SJAPCD's assumed 91% removal efficiency. Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032).

95%.[139] However, the lower NOx rate of 11 ppmv that SJVAPCD has adopted for lean-burn engines not used for compression and not operated at limited use (less than 4,000 hours per year) would also be achievable with SCR alone or with combustion controls plus SCR. A NOx limit of 11 ppmv reflects 99% control from uncontrolled levels.

More recently, EPA's 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls developed the following cost equations for SCR on natural gas four-stroke lean-burn engines, based on cost calculations for engines of varying size and annual capacity factor from SJVAPCD's 2003 cost effectiveness analysis:

Capital cost = $107.1 x (hp) + $27,186

Annual cost = $83.64 x (hp) + $14,718

The annual cost equation given above includes capital costs amortized assuming a 7% interest, which as discussed above is too high, and a 10-year equipment life, which should be 20 years as discussed above.[140] In the table below, the cost effectiveness of SCR based on these cost equations from EPA's 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls but revising the annual costs to reflect a 5.5% interest rate and a 20-year life of SCR and reflecting operations at 2,000 hours per year and at 8,000 hours per year. EPA's cost equations given above are based on an assumed 90% NOx reduction across the SCR, [141] so the same level of NOx control was assumed in the revised cost calculations presented in Table 13. Higher levels of NOx reduction and lower emission limits can be met with SCR alone or in combination with combustion controls. However, because higher levels of NOx reduction could also increase the operational expenses of SCR (unless some of the NOx reductions were achieved with combustion controls), the same 90% level of NOx control was assumed in the revised cost effectiveness analyses presented below to be consistent with the basis of EPA's cost equations.

[139] EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.
[140] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 5-11 to 5-12.
[141] *Id.*

Table 13. Cost Effectiveness to Reduce NOx by 90% from 4SLB RICE with SCR Operating at 23% and 91% Capacity Factors, Based on EPA's 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls[142]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF SCR, 2001$	COST EFFECTIVENESS OF SCR, 2,000 HOURS PER YEAR, 2001$	COST EFFECTIVENESS OF SCR, 8,000 HOURS PER YEAR, 2001$
4SLB	50	$17,509	$10,194/ton	$2,548/ton
	200	$29,368	$4,289/ton	$1,072/ton
	500	$53,086	$3,108/ton	$777/ton
	1,000	$92,617	$2,714/ton	$679/ton
	1,500	$132,148	$2,583/ton	$646/ton

Application of SCR to lean-burn RICE is cost effective for a wide range of engine sizes and types.

While the cost estimates and cost algorithms are of a cost basis that is twenty years old, the cost data have been relied on extensively.[143] And, from at least 2001, it is important to note that several state and local air agencies have found that the costs of control to achieve NOx emission limits of 1 g/bhp-hr (65 ppmvd) and even lower (as low as 11 ppmvd as required by SJVAPCD and SCAQMD) were cost effective to require such a level of control on existing lean-burn RICE rated greater than 100 hp. This will be discussed further in Section II.G. below. It is not possible to accurately escalate these costs to 2019 dollars. The CEPCI has been used extensively by EPA for escalating costs, but EPA states that using the CEPCI indices to escalate costs over a period longer than five years can lead to inaccuracies in price estimation.[144] Further, the prices of air pollution control do not always rise at the same level as price inflation rates. As air pollution control is required to be implemented more frequently over time, the costs of air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc.

The environmental and energy impacts of SCR for lean-burn RICE include the following:

- 0.5% increase in fuel consumption resulting in increased CO_2 emissions
- 1 to 2% reduction in power output[145]

[142] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 5-12. Note that EPA assumes the cost basis is 2001$. Annualized costs of control were calculated using a capital recovery factor of 0.083679 (assuming a 20-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032).

[143] EPA relied on the 2003 SJVAPCD Cost Effectiveness Analysis for Rule 4702 (which, in turn, relied on the 2001 CARB Guidance for Stationary SI Engines) in its 2016 EPA CSAPR TSD for Non-EGU NOx Emission Controls (Appendix A at 5-10 through 5-12).

[144] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.

[145] *See* EPA 1993 Alternative Control Techniques Document for RICE, Table 2-7 at 2-15.

- Increased solid waste disposal from spent catalysts[146]
- If ammonia is used instead of urea (which is assumed to be the reagent used in the SCR cost analyses presented above), there would be an increased need for risk management and implementation and associated costs.[147] If urea or aqueous ammonia is used as the reagent, the hazards from the use of pressurized anhydrous ammonia do not apply.

Regardless of these impacts, SCR technology is widely used at many industrial sources. There are typically not overarching non-air quality or energy concerns with this technology, and many of the concerns are addressed in the cost analysis.

In terms of length of time to install SCR at a lean-burn RICE unit, EPA has estimated that it takes 28–52 weeks to install SCR at a diesel-fired RICE unit.[148] It is reasonable to assume a similar time for the installation of SCR at a lean-burn natural gas-fired RICE unit.

F. RICE ELECTRIFICATION

Replacement of RICE with an electric motor is another pollution control option. In its 2001 guidance to California Air Districts, CARB indicated that electrification would be a NOx control option for RICE, with the potential to significantly reduce NOx emissions.[149] *Replacement of on-site engines with electric motors will reduce on-site NOx and other pollutant emissions by 100%.* Depending on the power source used for providing electricity to the site, air emissions may increase from the power generating site (i.e., if the power generating source is fueled by fossil fuels, rather than renewable energy such as wind or solar). However, even if the power is produced by a fossil fuel-fired power plant, it is likely more cost effective to a fossil fuel-fired power plant than it is to apply air pollution controls to individual engines.

CARB indicated in its 2001 guidance that "the majority of beam-balanced and crank-balanced oil pumps in California are driven by electric motors."[150] Thus, it stands to reason that electrification of such oil pumps is cost effective, given the widespread implementation.

CARB also found that electrification of RICE that fall within a size range from 50 to 500 hp would be a cost effective NOx control, but CARB stated that beyond the range of 50 to 500 hp, "modification and installation costs may become so extensive that this approach may not be cost effective."[151] However, on a cost per ton of NOx removed basis, CARB found that the electrification of engines in the 500 to 1,000 hp size range was as cost effective as the electrification of engines in the 50–150 hp size range –

[146] *See* CDPHE RP for RICE at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, EPA, Office of Air Quality Planning and Standards, RTP).
[147] Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.
[148] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls at 15.
[149] CARB 2001 Guidance at I-7.
[150] *Id.* at IV-2.
[151] *Id.* at V-2.

that is, $1,100/ton in 1999 dollars.[152] For engines in the size range of 150 to 500 hp, electrification of engines was somewhat more cost effective at $900/ton in 1999 dollars.[153] CARB indicated that Air Districts in California should consider the replacement of engines with electric motors as a control option "whenever it is feasible in order to maximize emission reductions."[154]

It is important to note that CARB's cost effectiveness calculations were based the assumption of only 2,000 hours per year operation, and CARB assumed capital costs would be amortized over a 10-year period and at a 10% interest rate.[155] There is no basis for assuming such a short lifespan for an electric internal combustion engine. As discussed further above, gas-fired RICE units have a useful life of at least 30 years, and many have been in operation much longer than 30 years.[156] Had CARB assumed a 30-year life of controls, the annualized cost of a new electric compressor over 30 years would be significantly lower than CARB's assessment of those costs over 10 years. Further, for an engine that operates more than 2,000 hours per year, replacement with an electric engine will reduce more NOx emissions, which would also make the replacement of an engine with an electric engine more cost effective.

More recently, EPA's Natural Gas STAR Program issued a Fact Sheet which evaluated the methane-reduction benefits of replacing gas-fired reciprocating compressors with electric compressors.[157] According to EPA, "[t]he EPA's Natural Gas STAR Program provides a framework for Partner companies within U.S. oil and gas operations to implement methane reducing technologies and practices and document their voluntary emission reduction activities."[158]

The Fact Sheet documents the costs of replacing five existing gas-fired reciprocating compressors with four electric compressors.[159] This Fact Sheet was made available in 2011, and thus the cost basis is assumed to be either from 2010 or 2011. Specifically, the Fact Sheet indicates that a partner replaced two 2,650 hp reciprocating compressors, two 4,684 reciprocating compressors, and one 893 hp reciprocating compressor with four 1,750 hp electric compressors.[160] The Fact Sheet states that the total cost of the replacement was $6,050,000, including the cost of the motor and compressor.[161] The Fact Sheet calculated the cost of electricity as the primary operating expense, and the electricity costs assuming continual operation of the compressors throughout the year were estimated to be $6,800,000

[152] *Id.* at V-3.
[153] *Id.*
[154] *Id.* at VII-2.
[155] *Id.* at V-4 to V-4.
[156] *See*, *e.g.*, EPRI, 20 Power Companies Examine the Role of Reciprocating Internal Combustion Engines for the Grid, *available at*: https://eprijournal.com/start-your-engines/. The authors also note that, in reviewing permits for gas processing facilities and compressor stations in New Mexico, it is not uncommon to have engines that were constructed from the 1950s to 1970s still operating at such facilities.
[157] *See* EPA, Partner Reported Opportunities (PROs) for Reducing Methane Emissions, PRO Fact Sheet No. 103 Install Electric Compressors, 2011, *available at*: https://www.epa.gov/sites/production/files/2016-06/documents/installelectriccompressors.pdf.
[158] *See* https://www.epa.gov/natural-gas-star-program/natural-gas-star-program.
[159] *See* EPA, Partner Reported Opportunities (PROs) for Reducing Methane Emissions, PRO Fact Sheet No. 103 Install Electric Compressors, 2011.
[160] *Id.* at 2.
[161] *Id.*

per year.[162] For electric compressors that operated less than every hour of the year, these operating costs can be scaled back by multiplying the projected electricity cost for continual operation by the ratio of the number of hours operated per year to 8,760 hours per year. Maintenance costs were assumed to be approximately 10% of the capital costs, and the maintenance costs would be lower than apply to gas-fired engines.[163] The Fact Sheet also presents the fuel gas savings for not having to pay for the natural gas to fire the reciprocating compressors based on three prices for natural gas ($3.00 per thousand cubic feet (MCF) of gas, $5.00 per MCF, and $7.00 per MCF).[164] The amount of natural gas saved by changing to electric compressors was estimated to be 1,700,000 MCF, assuming continual (8,760 hours) operation throughout the year and 20% efficiency of the gas-fired reciprocating compressors.[165] Because this analysis was focused on reducing methane emissions, no calculations of cost effectiveness of this control was done for NOx or any other pollutant.

With these data, the cost effectiveness of replacing similar-sized existing reciprocating compressor engines with similar-sized electric compressor engines as a NOx control measure can be calculated. For these calculations, it is assumed that the existing gas-fired reciprocating compressor engines are uncontrolled for NOx and thus emitting NOx at 16.8 g/bhp-hr.[166] To reflect compressor engines operating at varying hours per year, cost effectiveness calculations were done for replacing compressor engines operating at 2,000 hours, 4,000 hours, and 8,000 hours per year. The capital costs of the new electric compressors were amortized over a 30-year expected life of the new electric compressor engines, assuming a 5.5% interest rate consistent with EPA's Control Cost Manual methodology. The results of this analysis are provided in Table 14 below.

[162] *Id.* This assumed that the four 1,750 hp compressor engines had 50% efficiency, operated 8,760 hours per year, and electricity cost $0.075/kW-hr.
[163] *Id.*
[164] *Id.*
[165] *Id.* A heating value of natural gas of 1,020 British Thermal Units (BTU) per standard cubic feet (SCF) of gas was also assumed.
[166] *See* EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.

Table 14. NOx Cost Effectiveness to Replace Natural Gas-Fired RICE Units with Electric Compressor Engines[167]

	Costs at Operating Hours per Year (2011 $)		
	2,000 hours/yr	**4,000 hrs/yr**	**8,000 hrs/yr**
Annualized Capital Costs of New Electric Engines	$506,385	$506,385	$506,385
Annual Operating Costs of New Engines and Excluding Costs of Gas for Replaced Engines	$992,940	$1,380,880	$2,156,761
Total Annual Costs	$1,887,265	$1,887,265	$2,663,146
NOx Removed, tpy	542 tpy	1,084 tpy	2,168 tpy
NOx Cost Effectiveness at Stated Hours/Year	$2,766/ton	$1,741/ton	$1,228/ton

Assumptions

- Existing Gas-Fired Reciprocating Compressor Engines: 2–2,650 hp, 2–4,684 hp, 1–893 hp
- Replacement Electric Compressor Engines: 4–1,750 hp
- Efficiency of Existing Gas-Fired Engines: 20%
- Efficiency of Electric Engines: 50%
- 30 Year Life of Electric Engines, 5.5% Interest Rate
- Cost of Electricity: $0.075 per kilowatt-hour; Cost of Natural Gas: $3.00/MCF[168]
- Annual Maintenance Costs: 10% of Capital Costs of New Electric Engines

The above cost effectiveness analysis does not take into account the increased emissions that may occur from the electric power generation that will power the new electric compressor engines, which will depend on the source of that power for the new electric engines. If the energy is provided by renewable sources, there will be no NOx, greenhouse gas, or other air pollution increase associated with the energy production. To take into account the increase in NOx from a fossil fuel-fired power plant providing the electricity to the electric compressor engines, a high-end estimate of the increase in NOx from fossil-fuel fired power plant would mean that the switch to electric engines would result in an overall NOx emission reduction of about 97% of the NOx emitted by the gas-fired reciprocating compressor engines (i.e., a power plant providing the electricity for the new electric compressor engines might increase NOx by 15 to 59 tons per year depending on the hours of operation of the new electric compressor

[167] The basis for the capital and operating costs are from EPA's PRO Fact Sheet No. 103 Install Electric Compressors.
[168] The $3.00/MSCF estimated cost of natural gas may overestimate natural gas prices. The EIA reported the Henry Hub Spot Price for 2019 to be $2.66/MCF and has projected the cost to stay similar or decrease slightly in 2020-2021. However, the Henry Hub spot price was higher ($3.27/MCF) in 2018. Further, the EIA lists the 2019 Industrial Sector price of natural gas to be $3.90. It is not clear which of these two prices would apply, and thus the assumed $3.00/MCF price of natural gas is a middle ground between these two prices. *See* https://www.eia.gov/outlooks/steo/report/natgas.php.

engines).[169] From the perspective of cost effectiveness, the potential increase in NOx emissions from the power generating source would not significantly impact cost effectiveness of replacing gas-fired engines with electric engines.

The costs in Table 14 assume that the engines are located relatively close to the power grid and thus do not take into account any costs to bring electricity to the site. For a site that is not relatively close to the power grid, CARB estimated it could cost $5,000 to $10,000 (in 1999 dollars) to set up the site for electric motor operation and states that some utilities may waive or refund those costs if monthly energy usage matches the cost to connect to the grid.[170]

There are many benefits associated with replacing gas-fired reciprocating compressor engines with electric compressor engines. Those benefits include: [171]

- Reduced maintenance requirements and costs.
- Electric engines are more efficient than gas-fired engines.
- Lower noise levels with electric motors compared to gas-fired engines.
- No on-site emissions of other air pollutants.

An additional benefit of replacing gas-fired engines with electric engines is the greenhouse gas reductions that would be achieved. With renewable energy accounting for a larger share of electricity production over time, there could be significant reductions in greenhouse gases by using electrified engines powered by renewable energy. In the EPA's Natural Gas STAR Program Fact Sheet for electric compressors, the gas savings by electrifying the compressors is stated to be 32,800 MCF per year.[172] With that amount of gas not being combusted in the compressor engines and the power for the compressor engines being supplied by renewable energy, there would be a decrease in greenhouse gas emissions of almost 2,000 tons per year.[173] With electric compression engines used, there also will be less methane released from compressor blowdowns. Compressors must be taken offline at times due to emergency upsets and due to maintenance. As previously stated, the maintenance requirements with an electric compressor engine are significantly less with electric compressor engines.[174] It also seems likely that an electric engine would be less prone to upsets that cause the engine to go offline, compared to a gas-fired reciprocating engine. Moreover, with no gas used in the compressor engine, fugitive emission leaks due to fuel gas are also eliminated. EPA's Natural Gas STAR Program Fact Sheet provided an estimate that methane emissions savings from replacing the five gas-fired compressor engines with electric engines could be as high as 16,000 MCF per year, based on a methane emission factor of 2.11

[169] A NOx rate of 1.4 pounds per megawatt-hour was assumed for these calculations to represent a high-end estimate of the increase in NOx emissions if a fossil fuel-fired power plant provided the electricity for the electric engines. This reflects a NOx limit of 0.15 lb/MMBtu for a coal-fired power plant, which reflects a plant burning subbituminous coal with combustion controls. A natural gas-fired power plant would likely have a lower NOx rate, particularly if equipped with SCR.
[170] CARB 2001 Guidance at V-2.
[171] *See* EPA, PRO Fact Sheet No. 103 Install Electric Compressors at 2.
[172] *Id.* at 1.
[173] Calculated based on EPA's greenhouse gas emission factors for natural gas combustion in Table C-1 of Subpart C of 40 C.F.R. Part 98.
[174] *See* EPA, PRO Fact Sheet No. 103 Install Electric Compressors at 2.

MCF per horsepower.[175] Using the 100-year global warming potential identified by EPA,[176] that equates to roughly 10,000 tons per year of CO_2 equivalent emissions that would be avoided with no natural gas releases due to blowdowns with electric compressor engines. Thus, the total CO_2 equivalent emissions that could be reduced by replacing the five gas-fired engines with electric compressors powered with renewable energy would be about 12,000 tons per year.

There are several examples of electric engines being used in the oil and gas industry for compression, both at the wellhead and in compressor stations,[177] for drill rigs,[178] and in oil pumps.[179] Ambient air quality concerns have typically been the driver for electrification of engines in the past. Electrification of RICE units can be a very cost effective way to eliminate NOx and other air emissions, including greenhouse gas emissions, for the oil and gas industry and thus should be given serious consideration as an effective pollution control to address regional haze.

G. NOx EMISSION LIMITS THAT HAVE BEEN REQUIRED FOR EXISTING NATURAL GAS-FIRED STATIONARY RICE UNITS

The NSPS standards applicable to stationary spark ignition gas-fired RICE units were last reviewed and revised in 2008.[180] The most stringent NOx limit of those standards currently in effect for new and modified spark ignition RICE units is 1.0 g/hp-hr for rich burn engines greater than 100 hp and for lean-burn engines between 100 hp and 1,350 hp.[181] In considering reasonable progress controls for gas-fired spark-ignition RICE units, the applicable NSPS standards should be considered the "floor" of potential NOx controls to consider for an existing RICE unit.

Numerous states and local air agencies have adopted similar or more stringent NOx limits for existing spark-ignition gas-fired RICE units to meet, many of which have been in place for 10–20 years. In Table 15 below, we summarize those state and local air pollution requirements. Some of this information was initially obtained from EPA's 2016 CSAPR TSD,[182] which provided a summary of state NOx regulations for gas engines.[183] The current state/local requirements for those CSAPR states were confirmed by a review of the state and local rules. The CSAPR TSD focused on the rules applicable in the CSAPR states. A review of California Air District rules was also done for this report, because several of those air districts have adopted the most stringent NOx emission limitations for existing gas-fired engines. We reviewed many of the remaining states' regulations to determine whether there were NOx limitations for existing natural gas-fired stationary RICE units.

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[175] *Id.* at 1.
[176] *See* https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#Learn%20why.
[177] Armendariz, Al, Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements, prepared for Environmental Defense Fund, January 26, 2009, at 29-30, *available at*: https://www.edf.org/sites/default/files/9235_Barnett_Shale_Report.pdf.
[178] *Id.* at 18.
[179] CARB 2001 Guidance at IV-2.
[180] *See* 40 C.F.R. Part 60, §60.4230(a)(5) and Subpart JJJJ. 73 Fed. Reg. 3568 (1/18/08).
[181] 40 C.F.R. Part 60, Subpart JJJJ, Table 1.
[182] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix B at 14-15.
[183] *Id.*

Table 15 is a summary of the NOx emission limits required of existing gas-fired stationary RICE units in states and local air districts across the United States. It is important to note that these are limits that, unless otherwise noted, currently apply to existing RICE. Unlike the NSPS standards of 40 C.F.R. Part 60, Subpart JJJJ, the RICE did not have to be modified to trigger applicability to these emission limits. Instead, these emission limits apply to existing natural gas-fired stationary RICE units and generally required an air pollution control retrofit. These state and local NOx limits were most likely adopted to address nonattainment issues with the ozone NAAQS and possibly also the $PM_{2.5}$ NAAQS. However, Colorado adopted a NOx limit for lean-burn RICE of 1 g/hp-hr as part of its initial regional haze plan to achieve reasonable progress towards the national visibility goal.[184] Regardless of the reason for adopting the NOx emission limits, what becomes clear in this analysis is that numerous states and local governments have adopted NOx limitations that require NSCR at rich burn RICE units and either LEC or SCR at lean-burn RICE units. The lowest, most broadly applicable NOx limits are those recently adopted by SCAQMD which require gas-fired RICE units greater than 50 hp in size to meet a 11 ppmvd (equivalent to 0.15 g/hp-hr) NOx limit.

These limits were adopted generally to meet reasonably available control technology (RACT) and best available retrofit control technology (BARCT — applies in California), and costs are taken into account in making these RACT and BARCT determinations. However, RACT is not necessarily as stringent as BARCT. RACT is generally defined as: "devices, systems, process modifications, or other apparatus or techniques that are reasonably available taking into account: (1) The necessity of imposing such controls in order to attain and maintain a national ambient air quality standard; (2) The social, environmental, and economic impact of such controls."[185] BARCT, on the other hand, is defined as "an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."[186] BARCT is like a best available control technology (BACT) determination under the federal prevention of significant deterioration (PSD) program, but it evaluates controls to be retrofit to existing sources, rather than applying to new or modified sources.

Table 15. State/Local Air Agency RICE Rules for Natural Gas-fired Stationary RICE Units[187]

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
CA-Antelope Valley AQMD[188]	Rule 1110.2	Both	50–500 hp	45 ppmvd (0.67 g/hp-hr (RB) or 0.62 g/hp-hr (LB))
			>500	36 ppmvd (0.54 g/hp-hr (RB) or 0.49 g/hp-hr (LB))

[184] *See* CDPHE RP for RICE at 10.
[185] 40 C.F.R. § 51.100(o).
[186] HSC Code § 40406 (California Code), *available at*: https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=40406.&lawCode=HSC.
[187] This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules, but the authors recommend that readers check each specific rule for the details of how the rule applies to RICE units, and in case of any errors in this table.
[188] https://ww3.arb.ca.gov/drdb/av/curhtml/r1110-2.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
			Portable	80 ppmvd (1.19 g/hp-hr (RB) or 1.10 g/hp-hr (LB))
CA-Bay Area AQMD[189]	Reg. 9, Rule 8	RB	>50 bhp &/or not Low Usage (<100 hrs/yr) &/or not registered as portable	25 ppmv (0.37 g/hp-hr)
		LB	>50 bhp &/or not Low Usage (<100 hrs/yr) &/or not registered as portable	65 ppmv (0.89 g/hp-hr)
CA-Mojave Desert APCD[190]	Rule 1160[191]	RB	>500 bhp &/or >100 hours/4 quarters, and only if located in the Federal Ozone Nonattainment area	50 ppmv (0.75 g/hp-hr)
		LB		140 ppmv (1.92 g/hp-hr)
		RB		50 ppmv (0.75 g/hp-hr)
		LB		125 ppmv (1.71 g/hp-hr)
CA-Sacramento AQMD[192]	Rule 412	RB	>50 bhp & exemptions for 50-525 hp if low op hours (200-40 hrs)	25 ppmv (0.37 g/hp-hr) Alt Limit: 90% NOx Reduction
		LB	>50 bhp	65 ppmv (0.89 g/hp-hr) Alt Limit: 90% NOx reduction
CA-Santa Barbara AQMD[193]	Rule 333	RB	>50 bhp Noncyclically-loaded[194]	50 ppmvd (0.75 g/hp-hr) or 90% NOx reduction
		RB	>50 bhp	300 ppmvd (4.48 g/hp-hr)

[189] http://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-8-nitrogen-oxides-and-carbon-monoxide-from-stationary-internal-combustion-engines/documents/rg0908.pdf?la=en.
[190] http://mdaqmd.ca.gov/home/showdocument?id=438.
[191] http://mdaqmd.ca.gov/home/showdocument?id=6631.
[192] http://www.airquality.org/ProgramCoordination/Documents/rule412.pdf.
[193] https://ww3.arb.ca.gov/drdb/sb/curhtml/r333.pdf.
[194] Noncyclically loaded means an engine that is not cyclically loaded. *See* Santa Barbara AQMD Rule 333.C.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
			Cyclically-loaded[195]	
		LB	>50 bhp & < 100 bhp	200 ppmvd (2.74 g/hp-hr)
		LB	≥100 bhp	125 ppmvd (1.71 g/hp-hr) or 80% NOx reduction
CA – San Diego AQMD[196]	Rule 69.4.1	RB	>50 bhp &>200 hrs/yr	25 ppmvd (0.37 g/hp-hr)
		LB	>50 bhp &>200 hrs/yr	65 ppmvd (0.89 g/hp-hr)
CA-San Joaquin Valley APCD[197]	Rule 4702	RB	>50 bhp, Cyclic loaded, Field Gas Fueled	50 ppmvd (0.75 g/hp-hr)
		RB	>50 bhp & <4,000 hrs/yr	25 ppmvd (0.37 g/hp-hr)
		RB	>50 bhp and all others (engines not waste gas-fueled or cyclic loaded or limited hours)	11 ppmvd (0.16 g/hp-hr)
		2SLB	>50 bhp & <100 bhp	75 ppmvd (1.03 g/hp-hr)
		LB	>50 bhp & <4,000 hrs/yr	65 ppmvd (0.89 g/hp-hr)
		LB	>50 bhp and used for gas compression	65 ppmvd (0.89 g/hp-hr) or 93% NOx reduction
		LB	>100 hp and not limited use (<4,000 hrs), not used for gas compression, or not waste-gas fueled	11 ppmvd (0.15 g/hp-hr)
	Rule 431	RB	>50bhp &>200 hrs/yr	50 ppmvd (0.75 g/hp-hr)

[195] "Cyclically-loaded" means "an engine that under normal operating conditions has an external load that varies by 40% or more of rated brake horsepower during any load cycle or is used to power a well reciprocating pump including beam-balanced or crank-balanced pumps. Engines powering air-balanced pumps are noncyclically-loaded engines." *See* Santa Barbara AQMD Rule 333.C.

[196] https://www.sandiegocounty.gov/content/dam/sdc/apcd/PDF/Rules_and_Regulations/Prohibitions/APCD_R69-4-1.pdf.

[197] https://ww3.arb.ca.gov/drdb/sju/curhtml/r4702.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
CA- San Luis Obispo APCD[198]				or 90% NOx Reduction
		LB	>50bhp &>200 hrs/yr	125 ppmvd (1.71 g/hp-hr) or 80% NOx Reduction
CA - SCAQMD[199]	Rules 1110.2 and 1100	RB & LB	>50 bhp	11 ppmvd (0.16 g/hp-hr (RB) 0.15 g/hp-hr (LB))
CA- Ventura County AQMD[200]	Rule 74.9	RB	>50 bhp & >200 hrs/yr	25 ppmvd (0.37 g/hp-hr) or 94% NOx reduction
		LB	>50 bhp & > 200 hrs/yr	45 ppmvd (0.62 g/hp-hr) or 90% NOx reduction
TX- Houston-Galveston-Brazoria Area[201]	30 TAC 117.2010(c)(2) Emission Specs for 8hr ozone demo	RB & LB	>50 hp	0.50 g/hp-hr (33 ppmvd (RB) 36 ppmv (LB))
TX- Dallas -Ft. Worth Area[202]	30 TAC 117.2110(1) Emission Specs for 8hr ozone demo	RB	>50 hp	0.50 g/hp-hr
		LB	In service before 6/1/07	0.70 g/hp-hr
		LB	Placed into service, modified, reconstructed, or relocated after 6/1/07	0.50 g/hp-hr
NJ[203]	Rule 7:27-19.8	RB	>500 bhp	1.5 g/bhp-hr
		LB	>500 bhp	2.5 g/bhp-hr

[198] https://ww3.arb.ca.gov/drdb/slo/curhtml/r431.pdf.
[199] http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1110-2.pdf.
[200] http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.9.pdf.
[201] https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=2010.
[202] http://txrules.elaws.us/rule/title30_chapter117_sec.117.2110.
[203] https://www.nj.gov/dep/aqm/currentrules/Sub19.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
		LB & used for generating electricity	≥148 kW	1.5 g/bhp-hr or 80% NOx reduction
		2SLB	≥200 bhp & <500 bhp	3.0 g/bhp-hr
		4SLB	≥200 bhp & <500 bhp	2.0 g/bhp-hr
		RB&LB	Constructed or modified after 3/7/07, engines used to generate electricity with output ≥37 kW	0.90 g/bhp-hr or 90% NOx reductions (for modified units)
NY[204]	6 CCR-NY 227-2.4 (f)	RB & LB	>200 bhp	1.5 g/bhp-hr
MA[205]	310 CMR 7.19:(8)(c)	RB	>3 MMBtu/hr and >1,000 hrs	1.5 g/bhp-hr
		LB	>3 MMBtu/hr and >1,000 hrs	3.0 g/bhp-hr
MD[206]	COMAR 26.11.29.02.C.	RB	RICE used to compress nat gas ≥2400 hp	110 ppmv (1.64 g/hp-hr)
		LB	RICE used to compress nat gas ≥2,400 hp	125 ppmv (1.71 g/hp-hr)
CT[207]	22a-174-22e(d)(6a)	RB	>3 MMBtu/hr, until 5/31/23 Beginning 6/1/23	2.5 g/bhp-hr 1.5 g/bhp-hr
		LB	>3 MMBtu/hr, until 5/31/23 Beginning 6/1/23	2.5 g/bhp-hr 1.5 g/bhp-hr
IL (Chicago are and Metro East area)[208]	Title 35 Part 217, § 217.388a)1)	RB	Applies to specific engines listed in App G and those >500 bhp	150 ppmv (2.24 g/hp-hr)

[204] https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).
[205] https://www.mass.gov/files/documents/2018/01/05/310cmr7.pdf.
[206] http://mdrules.elaws.us/comar/26.11.29.
[207] https://www.ct.gov/deep/lib/deep/air/regulations/20160114_draft_sec22e_dec2015(revised).pdf.
[208] http://www.epa.state.il.us/air/rules/rice/217-subpart-q.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
		LB except Worthington engines not listed in App G	Applies to specific engines listed in App G and >500 bhp	210 ppmv (2.88 g/hp-hr)
		LB Worthington engines not listed in App G	>500 bhp & >8 MMbhp-hrs	365 ppmv (5.0 g/hp-hr)
GA (45 county area – ozone)[209]	Rule 391-3-1-.02.(2)(mmm) Applies only to engines used to generate electricity	RB & LB	≥100kW&<25 MW, in operation <4/1/00	160 ppmv (2.19–2.39 g/hp-hr)
		RB & LB	≥100k W&<25 MW, in operation >4/1/00	80 ppmv (1.10–1.19 g/hp-hr)
MI[210]	R 336.1818	RB	>1 ton/day NOx engines per avg ozone control period day in 1995	1.5 g/bhp-hr
		LB		3.0 g/bhp-hr
CO[211]	Reg. No 7, Sections XVIII.E. 2 and 3	RB	>500 hp constructed before 2/1/09	Install and operate both a NSCR and an AFRC by 7/1/2010
		RB or LB constructed or relocated to Colorado ≥1/1/11	≥100 hp & <500 hp	1.0 g/hp-hr
		RB or LB constructed or relocated ≥7/1/10	≥500 hp	1.0 g/hp-hr
MT[212]	ARM 17.8.1603	RB engines at "oil and gas well facilities" (which does not include Compressor engines) which completed or modified	>85 bhp	Install and operate NSCR or its equivalent to control air emissions

[209] http://rules.sos.ga.gov/GAC/391-3-1-.02.
[210] https://www.michigan.gov/documents/deq/deq-aqd-air-rules-apc-part8_314769_7.pdf.
[211] https://www.colorado.gov/pacific/cdphe/aqcc-regs.
[212] https://deq.mt.gov/Portals/112/DEQAdmin/DIR/Documents/legal/Chapters/CH08-16.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
		>3/16/79 and facility PTE NOx >25 tpy		
UT[213]	R307-510	Gas-fired engine at a well site that began operations, installed new engines or made modifications to existing engines after 1/1/16	≥100 hp	1.0 g/hp-hr

Most stringent NOx Limit of State/Local Rules:
11 ppmvd (0.15–0.16 g/hp-hr) applicable to either rich-burn or lean-burn RICE units greater than 50 bhp

In addition to the state and local air agency rules requiring NOx emission limits that clearly reflect highly effective NOx controls, some states have BACT or similar requirements that are required of new or modified sources regardless of whether or not such sources or modifications are major and subject to the major source PSD permitting programs. In some cases, states have issued guidelines on what is essentially considered BACT for these non-PSD new and modified sources, in the form of guidance and/or general permit or permit by rule requirements for RICE units. Table 16 below summarizes some of these state requirements which, when imposed in a permit would become binding emission limits.

[213] https://rules.utah.gov/publicat/code/r307/r307-510.htm.

Table 16. Other NOx Limits Applicable to Natural Gas-fired Stationary RICE Units

State	Determination	Applicability [hp]	NOx Limits and Engine Type Applicability [RB, LB or BOTH]
NEW JERSEY[214]	State of the Art (SOTA) Emission Performance Levels	NO SIZE SPECIFIED	0.15 g/hp-hr (BOTH)[215]
PENNSYLVANIA [216]	Best Available Technology (BAT) Emission Limits for new SI RICE permitted on or after 8/8/18	≤100	1.0 g/hp-hr
		>100 TO ≤500	0.7 g/hp-hr (LB) 0.25 g/hp-hr (RB)[217]
		>500	0.5 g/hp-hr (LB) 0.2 g/hp-hr (RB)
		≥2,370	0.3 g/hp-hr uncontrolled (LB) **or** 0.05 g/hp-hr with control (LB)[218]
PENNSYLVANIA [219]	Best Available Technology (BAT) Emission Limits for existing SI RICE permitted on or after	≤100	2.0 g/hp-hr
		>100 TO ≤500	1.0 g/hp-hr (LB)

[214] NJ DEP State of the Art Manual for Reciprocating Internal Combustion Engines (2003), *available at*: https://www.state.nj.us/dep/aqpp/downloads/sota/sota13.pdf.

[215] Generally applied controls to meet State of the Art Emission Performance Levels:

Rich-burn: NSCR

Lean-burn: SCR or LEC

Basis: "In determining SOTA performance levels for RICE engines, permitting agencies, industry associations, manufacturers of RICE and manufacturers of emissions control equipment were contacted to obtain updated information on emissions and control technologies. Databases for recent permitted and tested engines from New Jersey, California and USEPA were reviewed." *Id.* at 8.

[216] PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. *See* Tables 8 and 9, *available at*: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

[217] PA DEP determined that NSCR is required for all rich burn engines rated greater than or equal to 100 bhp. PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. *See* Appendix C at 75, *available at*: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

[218] Lean-burn engines greater than or equal to 2,370 hp have a dual BAT: (1) engines with a NOx emission rate of 0.30 g/bhp-hr do not require SCR based on economic feasibility; and (2) engines with a NOx emission rate of 0.050 g/bhp-hr require SCR.

[219] *Id.*

State	Determination	Applicability [hp]	NOx Limits and Engine Type Applicability [RB, LB or BOTH]
	2/2/13 but prior to 8/8/18		0.25 g/hp-hr (RB)[220]
		>500	0.50 g/hp-hr (LB) 0.20 g/hp-hr RB)
PENNSYLVANIA [221]	Best Available Technology (BAT) Emission limits for existing SI RICE permitted prior to 2/2/13	<1,500	2.0 g/hp-hr
WYOMING[222]	Oil and Gas Production Facilities Permitting Guidance Applicable to Natural Gas-Fired Pumping Units	≤50 hp AND MEETS BACT	2.0 g/hp-hr
TEXAS[223]	Oil and Gas Handling and Production Facilities Standard Permit RB engines manufactured on or after 1/1/2011; LB engines manufactured on or after 7/1/2010	≥100 bhp (RB) ≥500 bhp (LB)	1 g/bhp-hr

And in addition to the state guidance and/or general permit or permit by rule requirements for RICE units listed in Table 16, BACT analyses completed for PSD permits also demonstrate the feasibility of controls. As an example, in Missouri, BACT for lean-burn RICE at the Mid-Kansas Electric Company, LLC's

[220] PA DEP determined that NSCR is required for all rich burn engines rated greater than or equal to 100 bhp. PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. *See* Appendix C at 75, *available at*: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

[221] *Id.*

[222] WYDEQ Oil and Gas Production Facilities Permitting Guidance (last revised December 2018), *available at:* http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/FINAL_2018_Oil%20and%20Gas%20Guidance.pdf.

[223] TCEQ Air Quality Standard Permit for Oil and Gas Handling and Production Facilities (effective November 8, 2012), *available at:* https://www.tceq.texas.gov/assets/public/permitting/air/Announcements/oilgas-sp.pdf.

Rubart Station was determined to be SCR with a NOx BACT limit equivalent to 0.07 g/hp-hr for loads of 50% or higher.[224]

As Table 15 shows, twenty-three state and local air pollution control agencies have adopted NOx emission limits for existing gas-fired stationary RICE units that reflect the application of NSCR to rich-burn natural gas-fired RICE units greater than 50 hp and LEC and/or SCR for lean-burn natural gas-fired RICE units greater than 50 hp. These air agencies have thus found that the levels of NOx control listed in Table 15, including NOx limits as low as 11 ppmvd, are cost effective for existing natural gas-fired RICE units, providing relevant examples of one measure for states to consider in their second round haze plans to help make reasonable progress towards remedying existing visibility impairment. Further, several states have adopted essentially presumptive BACT NOx limits for new or modified RICE engines that are at least as stringent as the most stringent NSPS limit and/or apply to smaller units than the NSPS. The fact that these limits could apply to modified units means that the states consider retrofit controls to meet the emission limits in Table 15 above to be cost effective. Table 16 above also provides relevant examples of one measure for states to consider to prevent future impairment of visibility due to oil and gas development.

H. SUMMARY – NOx CONTROLS FOR EXISTING RICH-BURN AND LEAN-BURN NATURAL GAS-FIRED RICE

The above analyses and state/local rule data demonstrate that numerous state and local air agencies have found that NSCR is a cost effective NOx control for rich-burn natural gas-fired RICE units with costs ranging from $44/ton to $3,383/ton (2009$). NSCR not only reduces NOx, but can also be optimized with the use of an AFRC and an oxygen sensor to effectively reduce CO and HC and VOCs.

Further, numerous state and local air agencies have found that LEC is cost effective for lean-burn natural gas-fired RICE units with costs ranging from $74/ton to $941/ton (2001$). For the lowest NOx limit of 11 ppmvd applicable to lean-burn engines under rules adopted by SCAQMD and SJVAPCD, SCR was presumably necessary to meet these limits with costs ranging from $650 to $3,500 per ton of NOx removed or even higher for engines that operate 2,000 hours per year.

As states evaluate regulation of NOx emissions from natural gas-fired RICE units, there are several factors to consider, such as how the units are loaded (cyclically or not), operating capacity factor, and size. Nonetheless, given the numerous state and local NOx limits in Table 15 above that reflect operation of NSCR at rich-burn units and LEC or SCR at lean-burn units, these controls for rich-burn and lean-burn units rated at 50 hp or greater should generally be considered as cost effective measures available to make reasonable progress from natural gas-fired RICE units, given that similar sources have assumed similar costs of control to meet Clean Air Act requirements. NSCR has the added visibility benefit of reducing VOCs, as well as NOx.

[224] Prevention of Significant Deterioration Air Construction Permit Application for Mid-Kansas Electric Company, LLC Rubart Station (July 2012), *available at:* http://www.kdheks.gov/bar/midkanec/Mid-Kansas_Rubart_Station_PSD_Air_Permit_App_12_19_12.pdf.

It also must be recognized that it may be as or more cost effective for NOx control, and more beneficial for regional haze, to replace gas-fired RICE units with electric engines rather than install NOx pollution controls. Moreover, electric engines have numerous benefits that should be considered with regard to the energy and non-air impacts factor of a reasonable progress analysis. These additional benefits include reducing on-site emissions of all pollutants, reduced noise levels, more efficient operation and maintenance requirements (including less frequent maintenance required), and decreased methane emissions due to blowdowns because the electric engines do not require as frequent maintenance and do not have as many upsets. In addition, if the power for the electric engines can be derived from renewable energy sources, the greenhouse gas reductions can be very significant. Indeed, with renewable energy becoming an increasingly greater proportion of electricity generation and with coal-fired electricity generation being phased out, these added benefits of replacing gas-fired RICE units with electric engines should be considered in the four-factor analysis of controls. Electrification of engines may be less cost effective than some of the NOx controls evaluated above such as NSCR and LEC, but the potential added benefits with electric motors will likely weigh in favor of electrification as the most effective reasonable progress control for RICE.

III. CONTROL OF VOC EMISSIONS FROM NATURAL GAS-FIRED RICE

VOC emissions from natural gas-fired RICE units result from incomplete combustion. The same is true for CO emissions. The combustion conditions that favor lower NOx emission rates, such as lower temperature combustion, tend to result in less complete combustion and thus higher VOC as well as CO emission rates. In general, the emissions of VOCs from uncontrolled gas-fired RICE are of a lower magnitude compared to NOx emissions. A discussion of the pollution controls to reduce VOC emissions from these engines is provided below.

EPA's AP-42 Emission Factor documentation indicates that the uncontrolled VOC emission factors for natural gas-fired RICE in the range of 0.03 to 0.12 lb/MMBtu,[225] although it must be noted that EPA gives these emission factors a "C" rating. EPA's emission factor ratings indicate the reliability of the emissions factor, and a "C" rating reflects that "[t]ests are based on unproven or new methodology, or are lacking a significant amount of background information."[226] EPA also states that "actual emissions may vary considerably from the published emission factors due to variations in engine operating conditions."[227] That said, EPA's emission factors for uncontrolled VOCs are an order of magnitude lower than uncontrolled NOx emissions from RICE units. For that reason, this report focuses extensively on NOx emission controls for RICE units. However, there are emission controls feasible and implemented for VOCs from RICE units.

[225] EPA, AP-42, Section 3.2, Tables 3.2-1, 3.2-2, and 3.2-3, *available at*: https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf.
[226] EPA AP-42, Introduction at 8-9.
[227] EPA, AP-42, Section 3.2 at 3.2-3.

VOC Controls for Lean-Burn RICE

For lean-burn natural gas-fired RICE, as well as natural gas-fired combustion turbines, the primary method available for reducing VOC emissions is the use of an oxidation catalyst. For rich-burn RICE, NSCR is the pollution control of choice to address VOCs, as its three-way catalyst generally reduces NOx, CO, and VOCs with proper operation, although an oxidation catalyst can be installed downstream of the NSCR to improve VOC control.

A 2015 report issued by the Manufacturers of Emission Controls Association on emission controls for stationary internal combustion engines states as follows regarding oxidation catalyst for lean-burn engines:[228]

> Oxidation catalysts (or two-way catalytic converters) are widely used on diesel engines and lean-burn gas engines to reduce hydrocarbon and carbon monoxide emissions. Specifically, oxidation catalysts are effective for the control of CO, NMHCs, VOCs, and formaldehyde and other [hazardous air pollutants (HAPs)] from diesel and lean-burn gas engines. Oxidation catalysts consist of a substrate made up of thousands of small channels. Each channel is coated with a highly porous layer containing precious metal catalysts, such as platinum or palladium. As exhaust gas travels down the channel, hydrocarbons and carbon monoxide react with oxygen within the porous catalyst layer to form carbon dioxide and water vapor. The resulting gases then exit the channels and flow through the rest of the exhaust system.
>
> An oxidation catalyst has two simultaneous reactions:
>
> Oxidation of carbon monoxide to carbon dioxide:
> $2CO + O_2 \rightarrow 2CO_2$
>
> Oxidation of hydrocarbons (unburnt and partially burnt fuel) to carbon dioxide and water:
> $C_xH_{2x+2} + [(3x+1)/2]O_2 \rightarrow xCO_2 + (x+1)H_2O$

This 2015 report states that oxidation catalysts can reduce VOC emissions by 60–99%, as well as reduce CO emissions by 70–99%, non-methane HC by 40–90%, and formaldehyde and other hazardous air pollutants by 60–99%.[229] If a lean-burn engine is equipped with SCR for NOx control, an oxidation catalyst can be added to the SCR design.[230]

Cost information of oxidation catalyst was provided to EPA in 2010 to help determine national impacts associated with EPA's RICE NESHAP.[231] The analysis, performed by E^C/R Incorporated, was based on 2009 cost data for oxidation catalyst from industry groups, vendors, and manufacturers of RICE control

[228] *See* Manufacturers of Emission Controls Association, Emission Control Technology for Stationary Internal Combustion Engines, Revised May 2015, at page 8, Section 1.2.1, *available at*: http://www.meca.org/resources/MECA_stationary_IC_engine_report_0515_final.pdf.
[229] *Id.*
[230] *Id.* at 7.
[231] Memo from EC/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010).

technology. E^C/R Incorporated performed a linear regression analysis[232] on the oxidation catalyst cost data set for 2-stroke lean-burn engines and for 4-stroke lean-burn engines to establish an equation for each type of engine to estimate total annual cost and total capital costs as follows:

2SLB Oxidation Catalyst Total Annual Cost = $11.4 x HP + $13,928

2SLB Oxidation Catalyst Total Capital Cost = $47.1 x HP + $41,603

4SLB Oxidation Catalyst Total Annual Cost = $1.81 x HP + $3,442

4SLB Oxidation Catalyst Total Capital Cost = $1.81 x HP + $3,442

Where HP equals the engine size in horsepower.

E^C/R Incorporated developed equations to reflect total annual costs oxidation catalyst assuming a 7% interest rate and a 10-year life for amortizing the capital costs of control and adding in the annual operation and maintenance costs.[233] For the same reasons discussed regarding NSCR in Section II.C. above, it is reasonable to assume a 15-year life of oxidation catalyst controls at lean-burn RICE. Further, a lower interest rate of 5.5% is the appropriate interest rate to currently apply pursuant to the recommendations of EPA's Control Cost Manual for determining annualized capital costs of oxidation catalyst. Table 17 below provides the capital costs for oxidation catalysts at various size gas-fired lean-burn RICE and the total annualized cost of the control, assuming a 5.5% interest rate and a 15-year life.

Table 17. Capital and Annual Costs of Oxidation Catalyst at Lean-Burn RICE.[234]

ENGINE TYPE	HORSEPOWER	TOTAL CAPITAL COSTS	TOTAL ANNUALIZED COSTS
2SLB	50	$43,958	$12,619
	75	$45,136	$12,853
	100	$46,313	$13,088
	250	$53,378	$14,496
	500	$65,153	$16,843
	1000	$88,703	$21,536
	1500	$112,253	$26,229
4SLB	50	$3,533	$3,381
	75	$3,578	$3,425
	100	$3,623	$3,468
	250	$3,895	$3,727
	500	$4,347	$4,160
	1000	$5,252	$5,025
	1500	$6,157	$5,890

[232] *Id.* at 5-6.

[233] *Id.* at 5-6 and Appendix A.

[234] Cost calculations based on E^c/R equations from above, but assuming a 15-year life and a 5.5% interest rate.

A 2019 report by SCAQMD indicates that 500 stationary lean-burn engines have been fitted with oxidation catalyst.[235] In Colorado, sixty lean-burn RICE of sizes greater than 500 hp were required to install oxidation catalyst under the 2004 Denver Early Action Compact rulemaking.[236] As of July 1, 2010, Colorado requires all existing lean-burn RICE greater than 500 hp in the state's ozone action areas to install and operate an oxidation catalyst with an emission performance standard of 0.7 g/hp-hr.[237] Colorado only exempted lean-burn engines in the Denver area from the requirement to install oxidation catalyst if the cost was greater than $5,000/ton.[238] There are also several examples of oxidation catalyst being required as BACT for VOCs for lean-burn RICE. For example, in Missouri, BACT for lean-burn RICE at the Mid-Kansas Electric Company, LLC's Rubart Station was based on good combustion practices and an oxidation catalyst with a VOC BACT limit equivalent to 0.2 g/hp-hr for loads of 50% or higher.[239] In another example, BACT for RICE at the Irving Generating Station in Arizona was based on use of an oxidation catalyst with a VOC BACT limit (less formaldehyde) of 0.7 g/hp-hr.[240] In the BACT analysis for the Irving Generating Station several other recent examples were presented demonstrating consistent VOC BACT limits for natural gas-fired RICE, including limits as low as 0.3 g/hp-hr.[241]

In summary, oxidation catalyst is an available control technology that should be considered as a reasonable progress control option to reduce VOC emissions for lean-burn gas-fired RICE.

VOC Controls for Rich-Burn RICE

As discussed in Section II.C. above, NSCR is a three-way catalyst applicable to rich-burn RICE units, which not only removes NOx emissions, but also reduces CO and VOC emissions. In addition to the NSCR catalyst and housing, NSCR requires installation of an oxygen sensor and an AFRC ensure optimum air-to-fuel ratios to ensure conditions are NSCR is the primary VOC control that is implemented for rich-burn gas-fired RICE. Colorado has indicated that an "oxidation catalyst using additional air can be installed downstream of the NSCR catalyst for additional CO and VOC control."[242] The costs for NSCR have been detailed above in Section II.C. NSCR's cost effectiveness for NOx control and its widespread required use, as shown in the state and local air agency rules detailed in Table 15 above, indicates that NSCR must be considered as a reasonable progress control option to reduce VOC emissions from rich-burn RICE.

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[235] SCAQMD, Draft Staff Report, Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, September 2019, at D-1, *available at*: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1110.2/rule-1110-2-draft-staff-report---final.pdf?sfvrsn=6.

[236] *See* CDPHE RP for RICE at 3. *See also* Colorado Regulation No. 7, Part E, Section I.B., *available at*: https://drive.google.com/file/d/16qTQLSTX1T49DYWp3voXRNl4_g-vbhQT/view.

[237] Colorado Regulation 7 (5 CCR 1001-9) Part E 1. Control of Emissions from Engines.

[238] *Id.* at Section I.C.4. of Part E.

[239] Prevention of Significant Deterioration Air Construction Permit Application for Mid-Kansas Electric Company, LLC Rubart Station (July 2012), *available at:* http://www.kdheks.gov/bar/midkanec/Mid-Kansas_Rubart_Station_PSD_Air_Permit_App_12_19_12.pdf.

[240] Application for a Prevention of Significant Deterioration (PSD) Authorization and Significant Revision to Class I Air Quality Permit for Irving Generating Station, Tucson Electric Power (2017), *available at*: https://webcms.pima.gov/UserFiles/Servers/Server_6/File/Government/Environmental%20Quality/Air/TEP%20PSD%20Webpage/17-12-19-Sundt-RICE-Project-Revised-Application.pdf.

[241] *Id.* Table 5-3 at 5-10. Showing sources from Texas, Oregon, Kansas, and Hawaii receiving permits between 2013 and 2016.

[242] CDPHE RP for RICE at 6.

IV. CONTROL OF NOx EMISSIONS FROM NATURAL GAS-FIRED COMBUSTION TURBINES

Natural gas-fired combustion turbines are used in the oil and gas development industry generally for two purposes: (1) power generation and (2) compression. Combustion turbines are sometimes used to provide on-site power to gas processing facilities, or combustion turbines are used to drive compressors. There are several points in the oil and gas production process where compression of the natural gas is required to move the gas in the pipeline. When a combustion turbine is used for gas compression, the turbine drives the compressor, which is typically a centrifugal compressor. [243]

Gas turbines have been used for power generation since the late 1930s and are available in sizes as low as 500 kilowatts (kW) to over 300 Megawatts (MW).[244] Gas turbines produce a high-heat exhaust that can be recovered in a combined heat and power to produce steam to power a generator. This process is referred to as combined cycle power generation. However, in the oil and gas production industry, gas turbines are generally operated in simple cycle mode. Gas turbines can be used in remote locations such as oil and gas wellfields to provide distributed generation and portable power generation.[245] In some cases, combustion turbines are used at power plants developed for the purpose of providing power to oil and/or gas development but which are also selling electricity to the grid. If a power generating source is constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale, then it is considered an electric utility.[246] Although this specific analysis of controls will focus on the gas turbines used for gas compression or used for on-site power (i.e., "distributed generation") at oil and/or gas production and processing facilities, the available air pollution controls are the same for simple cycle turbines regardless of whether or not such turbines are part of an electric utility.

When combustion turbines are used to drive a compressor, there is no electrical generator (although there could be some heat recovery which could be used to generate electricity through a steam turbine).[247] Instead, the turbine shaft power is used as mechanical power to drive a compressor. Regardless of the purpose of the gas-fired combustion turbines, the air pollution controls for the associated visibility-impairing pollutants are the same.

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[243] *See*, *e.g.*, 76 Fed. Reg. 52,738 at 52,761 (Aug. 23, 2011); *see also* Innovative Environmental Solutions, Inc. & Optimized Technical Solutions, Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry, July 2014, at 26, note 1, *available at*: https://www.ingaa.org/File.aspx?id=22780.

[244] EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-1, *available at*: https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_3._technology_characterization_-_combustion_turbines.pdf.

[245] *Id.* at 3-2.

[246] 40 C.F.R. § 60.331(q).

[247] EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at S-2, 3-6, and A-2.

The 2012 Ozone Transport Commission Report refers to a report on costs of NOx controls at gas turbines prepared for the U.S. Department of Energy (DOE) in 1999.[248] That DOE Report, "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines" dated November 5, 1999 (hereinafter "1999 DOE Report")[249] is cited in several EPA and state documents on the cost of NOx controls at gas turbines, including in a Northeast States for Coordinated Air Use Management (NESCAUM) 2000 Status Report on NOx Controls for gas turbines and other sources,[250] which, in turn, serves as EPA's primary reference for the cost of SCR in its recently revised SCR chapter in its Control Cost Manual.[251] The NESCAUM 2000 Status Report on NOx controls also has other cost information for NOx controls for gas turbines. While these reports are twenty years old, the cost analyses have been relied on extensively by EPA and states.[252] In addition, more recent analyses of the costs of NOx controls for gas turbines have been summarized as supporting information for state and local air agency adoption of NOx emission limitations for gas turbines, but those cost analyses are generally not as detailed as the 1999 DOE report. In the discussion below of the NOx pollution control options for gas turbines, we provide information on all of these various cost analyses.

Note that in the following discussion, NOx emission rates are often referred to as parts per million or "ppm." It should be assumed that such concentration rates are in parts per million by volume or "ppmv" measured on a dry basis and corrected to 15% oxygen unless stated otherwise.

A. WATER OR STEAM (DILUENT) INJECTION

Water or steam injection has been used for decades to reduce NOx emissions from gas turbines. EPA describes the control in its "AP-42" emission factor documentation for gas turbines as follows:

> Water or steam injection is a technology that has been demonstrated to effectively suppress NOx emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.
>
> Depending on the initial NOx levels, such rates of injection may reduce NOx by 60 percent or higher. Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) but an increase in power output (typically 5 to 6 percent). The increased power output results from the increased mass flow required

[248] *See* 2012 OTC Report at 66-67.
[249] Bill Major, ONSITE SYCOM Energy Corporation, and Bill Powers, Powers Engineering, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, prepared for U.S. Department of Energy, November 5, 1999, Appendix A at A-5 (Table A-4), *available at*: https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf.
[250] NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness, at III-21 through III-24 and at III-40 [hereinafter "NESCAUM 2000 Status Report"], *available at*: http://www.nescaum.org/documents/nox-2000.pdf/view.
[251] *See* EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf 12 and 98 (reference 19).
[252] EPA relied on the cost analyses in the 1999 DOE Report for the Cross-State Air Pollution Rule. *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-10 through 3-18.

> to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection, with the level of CO and VOC increases dependent on the amount of water injection.[253]

The 1999 DOE Report on NOx pollution controls for gas turbines indicates that water or steam injection can achieve a NOx rate of 42 ppm.[254] In a more recent document, EPA states that water or steam injection enables a gas turbine to achieve NOx levels of 25 ppm at 15% oxygen.[255] General Electric also indicates that water injection can reduce NOx emissions to 25 ppm for gas-fired turbines.[256] The achievable NOx rate with water or steam injection likely depends on the uncontrolled NOx rate before water or steam injection, which can vary by turbine size and manufacturer.

Water injection has been a commonly applied retrofit NOx control technology for gas turbines for several decades. Water injection is available to most turbines; however, with advances in dry low NOx combustion techniques (discussed in the next section), it is not necessarily the first NOx control of choice given the lower cost and more effective options being available, depending on the turbine type. The turbine modifications necessary to accommodate water or steam injection could range from replacement of fuel nozzles with nozzles capable of supplying both fuel and water or steam, to replacement of the combustors with combustors designed to operate with water or steam injection, depending on the make and model of the combustion turbine.[257] There would also be other required equipment such as appropriate combustion turbine controls, an onsite water plant to demineralize water with storage or a storage tank for delivered demineralized water, a water injection pump, and a water or steam flow metering station.[258]

The 1999 DOE Report listed the capital and annual operating costs for water injection installed at specific makes/models of combustion turbines, which are reiterated in the table below.

Table 18. Capital and Operating Costs of Water or Steam Injection for Select Combustion Turbines[259]

Turbine Make/Model	Size, MW	Size, hp	Capital Costs of Water/Steam Injection 1999$	Annual Costs (Excluding Capital Recovery), 1999$
Solar Centaur 50	4.2 MW	5,632 hp	$405,500	$79,000
Allison 501-KB5	4.0 MW	5,364 hp	$291,000	$100,000
GE LM2500	22.7 MW	30,441 hp	$1,083,175	$294,000
GE MS7001F	161 MW	215,904 hp	$4,834,770	$1,325,000

[253] EPA, Compilation of Air Pollutant Emission Factors (AP-42), Section 3.1 Gas Turbines, April 2000, at 3.1-6.
[254] 1999 DOE Report, Appendix A at A-5 (Table A-4).
[255] EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.
[256] *See* GE Power, Water Injection for NOx Reduction, at https://www.ge.com/power/services/gas-turbines/upgrades/water-injection-for-nox-reduction.
[257] 2012 OTC Report at 62.
[258] *Id.*
[259] *See* 1999 DOE Report, Appendix A at A-5 (Table A-4).

The 1999 DOE report determined the annualized costs of control assuming only a 15-year life of controls and a 10% interest rate.[260] The DOE report provides no discussion as to why it assumed a 15-year life of controls, other than to state that EPA used the same 15-year life in a 1993 NOx control document.[261] There is no documented justification for assuming a 15-year life of water or steam injection controls for a combustion turbine. Instead, it is reasonable to assume that the design life of a combustion control like water or steam injection at a gas-fired combustion turbine is equal to the design life of the combustion turbine. A literature review indicates that 25 to 30 years is the design life of a gas combustion turbine.[262] Indeed, a review of permitted compressor stations and gas processing facilities in the state of New Mexico shows several combustion turbines operating today that were installed more than 30 years ago.[263] For the purpose of determining the annualized cost of controls, an assumption of a 25-year life of a water or steam injection system is more than reasonable and justified. Thus, to determine annualized costs based on the capital and operational expenses for water/steam injection presented in Table 18 above, a 25-year life of controls was assumed. Further, to be consistent with EPA's Control Cost Manual, which recommends the use of the bank prime interest rate,[264] a lower interest rate of 5.5% was assumed.[265] In its 2019 cost calculation spreadsheet for SCR provided with its Control Cost Manual, EPA used an interest rate of 5.5%.[266] The annualized costs of controls are presented for the four turbine types in Table 19 below.

The 1999 DOE Report calculated cost effectiveness of water or steam injection for the four turbine models listed in Table 18 above based on achieving a NOx rate of 42 ppm.[267] EPA relied on these cost estimates in its 2016 Technical Support Document for the Cross-State Air Pollution Rule regarding non-EGU NOx emissions controls, stating that the "generally accepted threshold" NOx emission rates that can be achieved with water injection was 42 ppmvd.[268] In its 2016 TSD for the CSAPR rule, EPA did not escalate the costs of controls from 1999 dollars.[269] As discussed above, lower NOx rates with water or steam injection of 25 ppm are generally achievable. Thus, in Table 19 below, the cost effectiveness of

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[260] *Id.* at 3-1. *See also* EPA's January 1993 Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (EPA-453/R-93-007) at 6-222 [hereinafter referred to as "1993 ACT for Stationary Gas Turbines"].

[261] In the 1993 NOx control document, EPA also assumed a 15-year life for SCR, when now EPA assumes a 20 to 30-year life of SCR systems, depending on the application. *See,* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 80.

[262] *See*, *e.g.*, Sargent & Lundy Combined-Cycle Plant Life Assessments, *available at*: https://sargentlundy.com/wp-content/uploads/2017/05/Combined-Cycle-PowerPlant-LifeAssessment.pdf; GE Power Generation, GE Gas Turbine Design Philosophy, *available at*: https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/technical/ger/ger-3434d-ge-gas-turbine-design-philosophy.pdf; NREL, Annual Technology Baseline, Natural Gas Plants, *available at*: https://atb.nrel.gov/electricity/2018/index.html?t=cg; Solar Turbines, Industrial Power Generation, Taurus 70, Benefits and Features, *available at*: https://www.solarturbines.com/en_US/products/power-generation-packages/taurus-70.html.

[263] *See* Title V air operating permits for Chaco Gas Plant, Pecos River Compressor, and Kutz Canyon Gas Plant, among others, available on the New Mexico Environment Department's website.

[264] US EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.

[265] *See e.g.*, https://fred.stlouisfed.org/series/DPRIME.

[266] *Available at* https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[267] *Id.* at A-3

[268] 2016 EPA CSAPR TSD for Non-EGU Emissions Controls, November 2015, Appendix A at 3-10 through 3-12.

[269] *Id.*

water/steam injection is calculated both to comply with a 42 ppm limit and a 25 ppm limit, based on a 25-year life and a 5.5% interest rate.

Table 19. Cost Effectiveness to Reduce NOx Emissions by Water or Steam Injection for Select Combustion Turbines Operating at 91% Capacity Factor[270]

Turbine Make/Model	Size, MW	Size, hp	Annualized Costs of Water/Steam Injection 1999$	Cost Effectiveness of Water/Steam Injection to Meet 42 ppm NOx Rate (1999$)	Cost Effectiveness of Water/Steam Injection to Meet 25 ppm NOx Rate (1999$)
Solar Centaur 50	4.2	5,632	$109,230	$1,496/ton	$1,265/ton
Allison 501-KB5	4.0	5,364	$121,694	$1,323/ton	$1,153/ton
GE LM2500	22.7	30,441	$374,750	$846/ton	$752/ton
GE MS7001F	161	215,904	$1,685,429	$409/ton	$373/ton

In sum, the cost effectiveness of water or steam injection at a gas-fired turbine is in the range of $1,150-$1,500/ton for the smaller turbines, $750 to $850/ton for a mid-sized turbine, and $375 to $410 for a large turbine. It must be noted that this cost effectiveness analysis is based on an assumed 8,000 hours of operation per year.[271] A 2012 document of technical information on the oil and gas sector available on the Ozone Transport Commission's website indicates that "on average a compressor unit will tend to experience an annual average capacity factor of approximately 40%."[272] This is presumably an average across all compressor engines used in the oil and gas sector, and there are very likely some compressors that do operate at 90% capacity factors. Indeed, the Ozone Transport Commission document indicates that "[f]or many mainline natural gas compressor stations, industry data indicated that the gas compressor stations have compressors in operation 24 hrs/day and 365 days/year, although not all compressors may be operating or may not be operating at high capacity."[273] Given that a compressor station typically is composed of multiple compressors either in parallel or in series powered either by combustion turbines or by reciprocating engines, it seems very likely that one or more of the compressors at a compressor station would operate at a high capacity factor while others would be operated at lower capacity factors, depending on the volume of gas that is being moved through the pipeline at the time. To provide a complete analysis of the range of costs of water or steam injection at a gas-fired combustion turbine, the cost effectiveness analysis of the 1999 DOE Report was revised to reflect a 40% capacity factor. Specifically, the fuel penalty cost (due to the reduction in turbine efficiency with water injection) and all costs dependent on the gallons of water used per year (i.e., the

[270] *See* 1999 DOE Report, Appendix A at A-5 (Table A-4). Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and a 91% operating capacity factor was assumed, reflective of the assumed 8,000 hours of operation per year in the November 1999 DOE Cost Analysis report.

[271] *Id.*, Appendix A at A-5.

[272] 2012 OTC Report at 16.

[273] *Id.*

water costs, water treatment costs, associated labor costs, and water disposal costs) in the annual costs of the 1999 DOE Report were reduced by 56% to reflect the reduction in operating hours when the units operate at a 40% capacity factor compared to a 91% operating factor.[274] Also, the tons of NOx reduced per year were revised to reflect operations at a 40% capacity factor.

Table 20. Cost Effectiveness to Reduce NOx Emissions by Water or Steam Injection for Select Combustion Turbines Operating at 40% Annual Capacity Factor[275]

Turbine Make/Model	Size, MW	Size, hp	Annualized Costs of Water/Steam Injection 1999$	Cost Effectiveness of Water/Steam Injection to Meet 42 ppm NOx Rate (1999$)	Cost Effectiveness of Water/Steam Injection to Meet 25 ppm NOx Rate (1999$)
Solar Centaur 50	4.2	5,632	$85,649	$2,675/ton	$2,257/ton
Allison 501-KB5	4.0	5,364	$90,021	$2,232/ton	$1,940/ton
GE LM2500	22.7	30,441	$255,506	$1,316/ton	$1,166/ton
GE MS7001F	161	215,904	$1,060,507	$587/ton	$533/ton

EPA's 2016 TSD for the CSAPR rule provided algorithms for estimating the total capital investment and the total annual costs of water injection based on the hourly heat input of the combustion turbine. These equations were based on a 1993 EPA Control Technique guideline as well as the 1999 DOE Report, and the total annual cost algorithms assumed a 15-year equipment life and a lower interest rate of 7%, but still high compared to today's interest rates.[276] The cost algorithms of EPA's 2016 TSD for the CSAPR Rule are reprinted below.[277]

Water Injection/Gas Turbines:

Total Capital Investment (1999 dollars) = 27665 x (MMBtu/hr)^0.69

Total Annual Costs (1999 dollars) = 3700.2 x (MMBtu/hr)^0.95

Steam Injection/Gas Turbines:

Total Capital Investment (1999 dollars) = 43092 x (MMBtu/hr)^0.82

Total Annual Costs (1999 dollars) = 7282 x (MMBtu/hr)^0.76

[274] It is possible that other items in the annual costs should also be reduced to reflect a 40% capacity factor, but it was not clear how to adjust those other costs.

[275] *See* 1999 DOE Report, Appendix A at A-5 (Table A-4). Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and a 40% operating capacity factor was assumed. The annual costs due to the fuel penalty, water use, water treatment, associated labor, and water disposal were decreased by 56% to reflect a 40% operating capacity factor as opposed to a 91% capacity factor.

[276] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-11 to 12 and Appendix B at B-2.

[277] *Id.,* Appendix A at 3-12.

While the cost estimates and cost algorithms are of a cost basis that is from 1999, it is important to note that beginning in the mid- to late-1990s, EPA and several state and local air agencies have found that the costs of control to achieve NOx emission limits of 42 ppmv or even lower were cost effective to require such a level of control on existing gas turbines. This will be discussed further in Section IV.D. below. It is not possible to accurately escalate these costs in 1999 dollars to 2019 dollars. The CEPCI has been used extensively by EPA for escalating costs, but EPA states that using the indices to escalate costs over a period longer than five years can lead to inaccuracies in price estimation.[278] Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. Moreover, as an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. Thus, the costs for water or steam injection are presented on a 1999 dollar cost basis in this report, but in any event, Table 29 in Section IV.D. of this report shows that numerous state and local air agencies found that water or steam injection was cost effective to require as a retrofit NOx pollution control at numerous gas turbines.

The environmental and energy impacts of the use of water or steam injection include the following:

- Requires the use of water, likely including a water treatment system, and disposal of wastewater
- Energy penalty due to decreased combustion turbine efficiency, but also increased power output
- May increase turbine maintenance requirements, depending on turbine type
- Can increase carbon monoxide and HC/VOC emissions[279]

Water use and water availability may be a significant environmental impact for this control technology, especially for locations in the arid West that already have water shortage issues. The 1999 DOE Report included information on expected water usage of water injection at the four turbines evaluated for the cost effectiveness analysis,[280] which can be projected into annual water use for water injection at these turbine types. The projected annual water use is provided in the table below, for both operating at a 91% capacity factor and at a 40% capacity factor. The amount of water needed for water injection is directly related to the operating capacity factor of the unit, with more water being needed for units operating at higher capacity factors.

Table 21. Projected Water Use of Water/Steam Injection at Gas-Fired Combustion Turbines[281]

Turbine Model	Size, MW	Annual Water Use at 91% Capacity Factor	Annual Water Use at 40% Capacity Factor
Solar Centaur 50	4.2	1,401,407	616,003
Allison 501-KB5	4.0	1,889,269	830,448
GE LM2500	22.7	7,093,130	3,117,859
GE MS7001F	161	95,166,555	41,831,453

[278] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.
[279] *See*, *e.g.*, EPA's 1993 ACT for Stationary Gas Turbines at 2-41.
[280] *See* 1999 DOE Report, Appendix A at A-5.
[281] *Id.*

As shown by the above table, water use with water/steam injection significantly increases with larger turbines and with units operated at higher capacity factors.

In addition to water availability, according to EPA, "[w]ater purity is essential for wet injection systems in order to prevent erosion and/or the formation of deposits in the hot sections of the gas turbine."[282] Water quality may be more of an issue for remote sites, especially if surface water or well water is used for the water supply.[283] The costs for the water use, treatment, and disposal, as well as the energy penalty costs, were taken into account in the annual costs of controls used in the NOx cost effectiveness analyses presented in Tables 19 and 20 above.[284]

Notwithstanding the high water usage, water or steam injection is a well-proven and cost effective control for NOx emissions from gas combustion turbines of all sizes. As is discussed in Section IV.D. below, NOx limits reflective of water or steam injection have been required by EPA and numerous state and local air agencies, and water or steam injection is used to control NOx at combustion turbines extensively throughout the U.S. However, for turbines constructed in the early 1990s or later,[285] dry low NOx combustion controls were much more commonly used at gas-fired combustion turbines than water or steam injection, due to lower costs of control, improved NOx control, and the fact that there would be no need for use and treatment of water.[286] Dry low NOx combustors are also available for retrofit for several turbine makes and models. This technology to control NOx is discussed in the next section of this report.

B. DRY LOW NOx COMBUSTION

In the late 1980s, dry low NOx burners (DLNBs) became available on larger turbines[287] and, currently, such controls are available on all new turbines. As described by EPA, "[l]ean premixed combustion . . . pre-mixes the gaseous fuel and compressed air so that there are no local zones of high temperatures, or 'hot spots,' where high levels of NOx would form. Lean premixed combustion requires specially designed mixing chambers and mixture inlet zones to avoid flashback of the flame."[288] Many DLNBs can achieve reduced NOx rates across the full load range of a gas turbine.[289] DLNBs are also available to retrofit to several types of combustion turbines. General Electric has dry low NOx burner retrofit

[282] *Id.* at 7-10.
[283] *Id.*
[284] 1999 DOE Report, Appendix A at A-5 (Table A-4).
[285] Dry low NOx combustors were first developed by GE in the early 1990s. *See* CARB, Report to Legislature, Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts, May 2004, at 19, *available at*: https://ww3.arb.ca.gov/research/apr/reports/l2069.pdf.
[286] *Id.* at 2-8.
[287] As discussed in Chapter 7, Controlling NOx Formation in Gas Turbines, by Brian W Doyle, September 2009, at 7-1, which is part of Chapter 10 of the EPA's Air Pollution Training Institute Class APTI 418, *available at*: https://www.apti-learn.net/lms/register/display_document.aspx?dID=39.
[288] EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.
[289] As discussed in 2012 OTC Report at 62.

options for many of its turbine makes and models, and Solar Turbines has an extensive line of retrofit kits including Solar Turbines' SoLoNOx™ technology.[290] To retrofit such DLNBs, the turbines' combustors must be replaced and there may be changes necessary to associated piping and turbine combustion controls.[291]

Based on the range of NOx emission rates that have been reported as achievable with DLNBs, these combustion controls can achieve in the range of 80% to 95% control of NOx emissions.[292] For the turbines for which DLNBs are available, NOx rates have generally ranged from 9–15 ppm.[293] The 1999 DOE Report assumed only a 25 ppmv NOx rate would be achieved at most of the combustion turbines with DLN combustion which reflects approximately 84% NOx reduction, although the DOE report also calculated costs for a larger turbine to meet a 9 ppmv NOx rate which reflects approximately 95% NOx reduction.[294] The 1999 DOE Report indicates that the operation and maintenance costs increase with the lower NOx rate being achieved.[295] The ability to achieve 9 ppmv NOx rates with dry low NOx combustors is not limited to large turbines, such as the GE Frame 7FA turbine (169.9 MW) for which the 1999 DOE Report calculated costs to achieve a 9 ppm NOx rate. Solar Turbines makes several turbines that are guaranteed to achieve 9 ppmvd NOx with Solar Turbines' SoLoNOx™ burners, including the Solar Centaur 50L which is rated at 6,276 horsepower (< 5 MW).[296] However, the ability to achieve 9 ppm NOx rates through dry low NOx combustor retrofits to existing turbines is likely more limited. Solar Turbines indicates that SoLoNOx™ retrofits are available for the Solar Taurus 70 gas turbine (11,110 horsepower).[297] GE recently announced NOx upgrades completed at 9 GE 9E Gas Turbines (132 145 MW) at a facility in China with its DLN1.0+ with Ultra Low NOx combustors to achieve about 7.5 ppm NOx rates.[298]

In its 2016 CSAPR TSD for Non-EGU NOx Emissions Controls, EPA relied on the cost analyses for DLNBs presented in the November 1999 DOE Report.[299] However, EPA acknowledged that, except for the costs for a 169 MW unit, the costs reported in the 1999 DOE Report are "incremental [costs] relative to the costs of a conventional combustor."[300] Table 22 below reflects the cost effectiveness calculations presented in the 1999 DOE report, but with changes made to the interest rate to reflect a 5.5% interest rate consistent with the EPA's Control Cost Manual and to change and life of the controls to the expected life of a combustion turbine of twenty-five years, as was done for the water/steam injection cost analyses. DLN combustors should be expected to last the life of a natural gas-fired combustion

[290] *Id.* at 66.
[291] *Id.*
[292] *See*, e.g., 2015 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-12, which indicates that 84% control can be met with DLNB achieving a NOx emission rate of 25 ppmvd.
[293] *See* 1999 DOE Report at 2-10.
[294] *Id.* at 2-10 and at Appendix A at A-3.
[295] *Id.* at 2-9 to 2-10.
[296] *See*, *e.g.*, Atlantic Coast Pipeline and Dominion Transmission, Inc., Supply Header Project, Resource Report 9, Air and Noise Quality, September 2015, at 9-24.
[297] *See* https://www.solarturbines.com/en_US/services/equipment-optimization/system-upgrades/safety-and-sustainability/solonox-upgrades.html.
[298] *See* https://www.genewsroom.com/press-releases/ge-completes-worlds-first-dln10-ultra-low-nox-combustion-upgrade-nine-ge-9e-gas.
[299] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-12.
[300] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-12. *See also* 1999 DOE Report at 3-3 and Appendix A at A-3.

turbine, which is at least twenty-five years as discussed above. Indeed, there are likely several examples of gas turbines with dry low NOx combustor retrofits that have operated for twenty-five years. The Tennessee Gas Pipeline Company's Compressor Station in Lockport, New York has four Solar Centaur Turbines that were retrofitted with dry low NOx combustion systems in 1995[301] (two of which continue to operate today, twenty-five years later, while the other two were replaced between 2012–2019 with turbines rated at a higher horsepower).[302]

Table 22. Summary of Cost Effectiveness for DLN Combustion (1999$) at 91% Capacity Factor[303]

Turbine Make/Model	Size, MW	Size, hp	Annualized Costs of DLN Combustion 1999$	Cost Effectiveness of Dry Low NOx Combustion to meet 25 ppm NOx Rate	Cost Effectiveness of Dry Low NOx Combustion to Meet 9 ppm NOx Rate
Allison 501-KB7	4.9	6,571	$33,491	$259/ton	
Solar Centaur 50	4.0	5,364	$14,164	$164/ton	
Solar Centaur 60	5.2	6,973	$14,164	$128/ton	
GE LM2500	22.7	30,441	$179,639	$360/ton	
GE Frame 7FA	169.9	227,839	$455,472 (25 ppmv) $474,109 (9 ppmv)	$96/ton	$92/ton

In Table 23 below, the cost effectiveness of dry low NOx combustors is calculated to reflect operation at a 40% capacity factor. Operating at a lower capacity factor should not change the operating or capital costs of the dry low NOx combustion system, given that there is no energy penalty requiring additional fuel use.

[301] NESCAUM 2000 Status Report at IV-36.

[302] *See* New York State Department of Environmental Conservation (NYDEC), Permit 9-2920-00008/00015, Mod 3 Effective 12/2/2014, Issued for the Tennessee Gas Pipeline Co Compressor Station 230-C, *available at*: https://www.dec.ny.gov/dardata/boss/afs/permits/929200000800015_r2_3.pdf. *See also* NYDEC Title V Operating Permit 9-2920-00008/00015 issued 10/23/2018 for the Tennessee Gas Pipeline Co Compressor Station 230-C, *available at*: https://www.dec.ny.gov/dardata/boss/afs/permits/929200000800015_r3.pdf.

[303] *See* 1999 DOE Report, Appendix A at A-3. Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a twenty-five -year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and a 91% operating capacity factor was assumed.

Table 23. Summary of Cost Effectiveness for DLN Combustion (1999$) at 40% Annual Capacity Factor[304]

Turbine Make/Model	Size, MW	Size, hp	Cost Effectiveness of Dry Low NOx Combustion to meet 25 ppm NOx Rate	Cost Effectiveness of Dry Low NOx Combustion to Meet 9 ppm NOx Rate
Allison 501-KB7	4.9	6,571	$590/ton	
Solar Centaur 50	4.0	5,364	$373/ton	
Solar Centaur 60	5.2	6,973	$292/ton	
GE LM2500	22.7	30,441	$820/ton	
GE Frame 7FA	169.9	227,839	$218/ton	$208/ton

EPA's 2016 TSD for the CSAPR rule provided algorithms for estimating the total capital investment and the total annual costs of DLN combustion based on the hourly heat input of the combustion turbine. These equations were based on a 1993 EPA Control Technique guideline as well as the 1999 DOE Report, and the total annual cost algorithms assumed a 15-year equipment life and a lower interest rate of 7%, which is still high compared to today's interest rates.[305] The cost algorithms of EPA's 2016 TSD for the CSAPR Rule for DLN combustion are reprinted below.[306]

Total Capital Investment (1999 dollars) = 2860.6 x (MMBtu/hr) + 25427

Total Annual Costs (1999 dollars) = 584.5 x (MMBtu/hr)^0.96

In its 2000 Status Report, NESCAUM provided information on the capital and operational expenses for two dry low NOx combustor upgrades to a Solar Centaur turbine (4,700 hp) and a Solar Mars turbine (13,000 hp).[307] Given that it appears the cost data in the 1999 DOE Report may not necessarily reflect retrofit costs (in that, with the exception of the costs for the GE Frame 7FA, the costs were identified in the 1999 DOE Report as "incremental" costs relative to the cost of a conventional combustor), the NESCAUM cost information for retrofit DLNC is also presented here. NESCAUM used a shorter useful life of controls than twenty-five years and a higher interest rate than the 5.5% interest rate used by EPA in its cost spreadsheets provided with its 2018 updates to the Control Cost Manual.[308] NESCAUM also assumed that DLNCs could only reduce NOx to 50 ppm, whereas such combustors should be able to reduce NOx to at least 25 ppm. Thus, in Table 24 below, the cost effectiveness of the DLNC retrofit projects discussed in the NESCAUM report are revised to reflect amortized capital costs assuming a 25-year life and a 5.5% interest rate and to reflect reducing NOx to both 50 ppm and to 25 ppm.

[304] *See* 1999 DOE Report, Appendix A at A-3. Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a twenty-five -year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and a 40% operating capacity factor was assumed.

[305] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-11-12, Appendix B at B-2.

[306] *See id.*, Appendix A at 3-13.

[307] *See* NESCAUM 2000 Status Report at III-16.

[308] *Id.*

Table 24. Summary of Cost Effectiveness for Retrofit DLN Combustion at 40% and 91% Annual Capacity Factors Based on Retrofit Costs Provided in 2000 NESCAUM Report[309]

Turbine Make/Model	Size, hp	Capacity Factor	Cost Effectiveness of Retrofit DLN Combustion to meet 50 ppm NOx Rate	Cost Effectiveness of Retrofit DLN Combustion to Meet 25 ppm NOx Rate
Solar Centaur	4,700	91%	$1,217/ton	$940/ton
Solar Centaur	4,700	40%	$2,769/ton	$2,140/ton
Solar Mars	13,000	91%	$359/ton	$296/ton
Solar Mars	13,000	40%	$816/ton	$673/ton

The NESCAUM 2000 Status Report notes that the capital costs reported for these two turbine types were the "total project costs the owners attributed to the project, which may include project management or other charges associated with the project beyond the equipment and installation."[310] Thus, the costs reflected in Table 24 may be higher than what would typically be reported for DLNC controls in a cost effectiveness analysis consistent with EPA's Control Cost Manual, because EPA does not generally allow such owner's costs to be considered in a cost effectiveness analysis.[311]

In terms of non-air environmental or energy impacts with the use of DLNCs, there are relatively few impacts. There is not an energy penalty associated with the operation of the DLNCs, nor is there any waste product that requires proper disposal. However, there can be increased maintenance required with DLNCs, and those additional maintenance costs are often proprietary.[312] In fact, the increased maintenance costs are not reflected in the cost analyses for the Solar Centaur 50 and Solar Centaur 60 turbines in Tables 22 and 23 above, due to the information being considered proprietary.[313] A non-air quality environmental impact is that DLNBs "tend to create harmonics in the combustor that result in significant vibration and acoustic noise."[314]

EPA has indicated that the length of time to install DLNBs is 6–12 months.[315]

As previously discussed, while the cost estimates and cost algorithms for DLN combustion are of a cost basis that is from 1999-2000, it is important to note that, beginning in the late-1990s, EPA and numerous several state and local air agencies have found that the costs of control to achieve NOx emission limits of 25 ppmv or even lower were cost effective to require such a level of control on existing gas turbines. This will be discussed further in Section IV.D. below.

[309] *Id.* at III-16. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and both a 91% and a 40% operating capacity factor were assumed.
[310] *Id.*
[311] *See* EPA Control Cost Manual, Section 1, Chapter 2 at 9.
[312] *Id.* at 2-9 and 3-10.
[313] *Id.*, Appendix A at A-3.
[314] *Id.* at 2-9 and Appendix A at A-3.
[315] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls at 18.

Given the lower costs compared to water or steam injection, along with lower operational costs and no need to have water nearby, it is clear why DLNC has been preferable to water or steam injection since such dry low NOx combustion systems have been available. However, as stated above, these DLNC systems are not available for retrofit for all gas-fired turbines and thus, for many turbines, water or steam injection would be the available combustion control. As Tables 22 through 24 show, DLNC is more cost effective than water or steam injection and can achieve lower NOx rates. Thus, low NOx combustion is a preferable combustion-related retrofit option for gas turbines, if a low NOx combustion retrofit option is available for the turbine make and model.

C. SELECTIVE CATALYTIC REDUCTION

SCR is a post-combustion NOx reduction control that is commonly applied to gas-fired combustion turbines used for power generation. SCR technology can reduce NOx emissions by 80–90% or more and, when used along with water injection or DLNC, it can achieve NOx emission rates in the range of 1.5 to 5 ppm.[316] The 1999 DOE Report stated that SCR was the "primary post-combustion NOx control method in use" as of 1999.[317]

An SCR system consists of a reagent injection system (typically ammonia or urea) and a catalyst. The ammonia or urea (which converts to ammonia in the flue gas) is injected into the exhaust stream and the flue gas then passes over a catalyst reduced NOx to N_2, H_2O, and CO_2. The catalyst selected depends on the temperature range of the flue gas and the size of the catalyst depends on the level of NOx reduction to be achieved. SCR technology requires a reagent injection system, including a storage tank and reagent injectors and controls to regulate the quantity of reagent, and the SCR catalyst. According to the 1999 DOE Report, the cost of conventional SCR had dropped significantly by 1999 with innovations in catalysts allowing for a significant reduction in catalyst volume with no change in NOx removal performance.[318] Catalysts are also available for SCR to work at a variety of flue gas temperatures, from as low as 300 degrees Fahrenheit to as high as 1,100 degrees Fahrenheit.[319] For simple cycle turbines, which are more commonly used in the oil and gas sector, the reactor chamber with the catalyst is in place directly at the turbine exhaust, which may require the use of high temperature catalyst such as zeolite.[320] Several options for SCR catalyst exist for simple cycle turbines. For example, BASF makes several SCR catalysts that it claims can achieve up to 97% NOx reduction.[321] The NOxCat ETZ catalyst is specifically designed for simple-cycle power generating turbines and other high temperature turbine applications.[322] The NOxCat VNX and ZNX catalysts can achieve up to 99%

[316] *See*, *e.g.*, EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18; 2012 OTC Report at 63.
[317] 1999 DOE Report at 1-5.
[318] *Id.*
[319] *Id.*
[320] *See* EPA, Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, at pdf page 36.
[321] *See* BASF, SCR Catalysts for Power Generation, *available at*: http://www.basf-qtech.com/p02/USWeb-Internet/catalysts/en/content/microsites/catalysts/prods-inds/stationary-emissions/scr-cat-pow-gen.
[322] *See* BASF, NOxCat ETZ, *available at*: http://www.basf-qtech.com/p02/USWeb-Internet/catalysts/en/content/microsites/catalysts/prods-inds/stationary-emissions/nOx-Cat-_ETZ.

NOx reduction and are most effective at a temperature range of 550 to 800 degrees Fahrenheit.[323] A related catalyst called NOxCat VNX-HT is designed for use in aeroderivative simple-cycle turbines that can achieve 99% NOx removal and can reach optimal performance at 800 to 850 degrees Fahrenheit.[324]

Conventional SCR systems can be used with simple cycle turbines if the gas stream is cooled to the optimal temperatures for conventional SCR catalysts, through air dilution or tempering.[325] Further, aeroderivative turbines typically have somewhat lower exhaust gas temperatures which can work better with conventional SCR systems than frame-type turbines.[326] The optimal temperature of the flue gas to both minimize the amount of catalyst needed and ensure the highest NOx removal (> 90%) is 700 to 750 degrees Fahrenheit for conventional SCR catalysts.[327] Conventional catalysts can achieve 80% or greater NOx removal over a wide temperature range of approximately 625 to 900 degrees Fahrenheit.[328] SCR vendors have experience installing SCR to achieve low NOx emission rates on numerous simple cycle turbines of all types and sizes.[329]

In its Control Cost Manual chapter on SCR, which was updated in 2019, EPA cites capital costs of SCR for simple cycle gas turbines that range from $237/kilowatt for a 2 MW gas turbine down to $50/kilowatt for a larger gas turbine, all in 1999 dollars cost basis.[330] For these cost ranges, EPA cites to the NESCAUM 2000 Status Report.[331] That NESCAUM report in turn relies on the 1999 DOE Report, as well as a 1991 report by the Electric Power Research Institute and some personal communications.[332] The NESCAUM 2000 Status report provides a range of cost effectiveness data based on these reports for the application of high temperature SCR to gas turbines of varying operating capacity factors, sizes, and baseline NOx emission rates. Table 25 below presents that data for turbines with year-round high temperature SCR operation.

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[323] *See* BASF, NOxCat VNX & ZNX for Power Generation, *available at*: http://www.basf-qtech.com/p02/USWeb-Internet/catalysts/en/content/microsites/catalysts/prods-inds/stationary-emissions/nox-cat-VNX-ZNX-pow-gen.

[324] *Id.*

[325] *See, e.g.*, Buzanowki, M. and S. McMenamin, Automated Exhaust Temperature Control for Simple-Cycle Power Plants, 2/11/2011, Power Magazine, *available at*: https://www.powermag.com/automated-exhaust-temperature-control-for-simple-cycle-power-plants/?printmode=1.

[326] Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand Curve Reset, prepared for New York Independent System Operator, Inc., at iv, *available at*: http://files.brattle.com/files/7644_independent_evaluation_of_scr_systems_for_frame-type_combustion_turbines.pdf.

[327] *See* EPA, Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, at pdf pages 20-21.

[328] *Id.* at pdf page 20.

[329] *See*, *e.g.*, McGinty, Bob, Mitsubishi Hitachi Power Systems, Gas Turbine & Industrial SCR Systems, Lessons Learned Firing NG and ULSD in Large Frame Simple Cycle Gas Turbine Hot SCR Systems, *available at*: http://cemteks.com/cemtekswp/wp-content/uploads/2016/12/lessons_learned_firing_ng_and_ulsd_in_large_frame_simple_cycle_gas_turbine_hot_scr_systems.pdf; Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand Curve Reset, prepared for New York Independent System Operator, Inc.

[330] US EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction (June 2019) at pdf page 12.

[331] *Id.* at pdf page 98 (see Reference 19).

[332] NESCAUM 2000 Status Report at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15).

Table 25. Cost Effectiveness for High Temperature SCR Retrofit on Simple Cycle Gas Turbines.[333]

Turbine Size, MW	Turbine Size, hp	Uncontrolled NOx, ppm	Controlled NOx, ppm	Cost Effectiveness of SCR, $/ton (2000$), at listed capacity factor	Capacity Factor
75	100,590	154	15	$849	45%
75	100,590	154	15	$664	65%
75	100,590	154	15	$566	85%
75	100,590	42	7	$2,980	45%
75	100,590	42	7	$2,247	65%
75	100,590	42	7	$1,859	85%
75	100,590	15	3	$8,441	45%
75	100,590	15	3	$6,303	65%
75	100,590	15	3	$5,171	85%
5	7,000	142	15	$3,395	45%
5	7,000	142	15	$2,523	65%
5	7,000	142	15	$2,061	85%
5	7,000	42	5	$11,335	45%
5	7,000	42	5	$8,341	65%
5	7,000	42	5	$6,756	85%

The different shading in the table reflects different levels of NOx combustion controls of the existing turbine:

- Gray shading reflects the cost effectiveness of SCR applied to gas turbines with no water injection or dry low NOx combustion controls, in which case the SCR was assumed to achieve about 90% NOx reductions.
- Blue shading reflects the cost effectiveness of SCR applied to gas turbines with, presumably, water injection which can achieve 42 ppm or lower NOx emission rates, in which case the SCR was assumed to achieve about 83–88% removal.
- Green shading reflects the cost effectiveness of SCR applied to gas turbines with, presumably, low NOx combustion controls that can achieve 15 ppm NOx, in which case the SCR was assumed to achieve 80% removal.

[333] *Id.* at III-24.

The NESCAUM cost effectiveness numbers in Table 25 above reflect a 15-year equipment life and an interest rate of 7.5%.[334] The NESCAUM cost effectiveness numbers were also primarily based on the 1999 DOE report.[335] However, EPA has indicated that a 25-year life is a more appropriate life of an SCR system at a gas turbine used in an industrial setting like a compressor station.[336] Further, as stated above, EPA currently uses a 5.5% interest rate in its cost effectiveness calculations. Tables 26 and 27 below present the cost effectiveness for conventional and high-temperature SCR added to a gas-fired combustion turbine meeting an uncontrolled rate of 42 ppmv, reflective of water or steam injection, to achieve a controlled NOx rate of 9 ppmv, which reflects a 79% reduction in NOx emissions. These cost effectiveness analyses are based on the costs of the 1999 DOE Report, but with the capital cost amortized to reflect a 25-year equipment life and a 5.5% interest rate.[337] The 1999 DOE cost analyses were based on operating 8,000 hours per year, or a 91% capacity factor. Given information previously cited that, on average, a compressor unit may operate at a 40% annual capacity factor,[338] revisions to the cost data and emissions reduced were made to reflect a 40% capacity factor. Specifically, the electricity costs (due to the parasitic load of the SCR system) and the ammonia costs in the direct annual costs of the 1999 DOE Report were reduced by 56% to reflect the reduction in SCR operating hours when the units operate at a 40% capacity factor compared to a 91% operating factor.[339]

[334] *Id.* at IV-22.
[335] *Id.* at III-21 through III-24 (see cites to Reference 11, which is the 1999 DOE report).
[336] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.
[337] 1999 DOE Report at 3-9 to 3-10, Appendix A at A-6 to A-7.
[338] 2012 OTC Report at 16.
[339] It is possible that other items in the direct annual costs should also be reduced to reflect a 40% capacity factor, but it was not clear how to adjust those other costs.

Table 26. Cost Effectiveness to Reduce NOx Emissions by Conventional SCR for Select Combustion Turbines with Existing Water or Steam Injection, Operating at Either a 91% or 40% Annual Capacity Factor[340]

Turbine Model	Size, MW	Size, hp	Uncontrolled NOx, ppm at 15% O2	Controlled NOx with SCR, ppm at 15% O2	Annualized Costs of SCR, 1999$	Cost Effectiveness of Conventional SCR at Stated Capacity Factor, 1999$	Capacity Factor
Solar Centaur 50	4.2	5,632	42	9	$135,475	$11,794/ton	40%
Solar Centaur 50	4.2	5,632	42	9	$143,368	$5,486/ton	91%
GE LM2500	22.7	30,441	42	9	$295,872	$6,098/ton	40%
GE LM2500	22.7	30,441	42	9	$317,134	$3,049/ton	91%
GE Frame 7FA	161	215,904	42	9	$1,426,883	$3,050/ton	40%
GE Frame 7FA	161	215,904	42	9	$1,317,285	$1,679/ton	91%

[340] 1999 DOE Report, Appendix A at A-6 (Table A-5). Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). To reflect a 40% capacity factor, the annual operating costs due to the fuel penalty and ammonia use were decreased by 56%, to reflect a 40% capacity factor rather than a 91% capacity factor. Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines.

Table 27. Cost Effectiveness to Reduce NOx Emissions by High Temperature SCR for Select Combustion Turbines with Existing Water or Steam Injection, Operating at Either a 91% or 40% Annual Capacity Factor[341]

Turbine Model	Size, MW	Size, hp	Uncontrolled NOx, ppm at 15% O2	Controlled NOx with SCR, ppm at 15% O2	Annualized Costs of SCR, 1999$	Cost Effectiveness of High Temperature SCR at Stated Capacity Factor, 1999$	Capacity Factor
Solar Taurus 60	5.2	6,973	42	9	$179,385	$13,238/ton	40%
Solar Taurus 60	5.2	6,973	42	9	$188,760	$6,123/ton	91%
GE LM2500	22.7	30,441	42	9	$324,122	$6,680/ton	40%
GE LM2500	22.7	30,441	42	9	$364,879	$3,305/ton	91%
GE Frame 7FA	161	215,904	42	9	$1,379,722	$3,695/ton	40%
GE Frame 7FA	161	215,904	42	9	$1,680,250	$1,978/ton	91%

Although the above costs reflect a 1999-2000 dollar cost basis, EPA has indicated that the costs of conventional SCR "have dropped significantly over time – catalyst innovations have been a principal driver, resulting in a 20% in catalyst volume and cost with no change in performance."[342] Moreover, high temperature SCR catalysts are not necessarily required for turbines operated in simple cycle mode, as was assumed in the NESCAUM 2000 report, because air tempering can be used to lower the cost of the exhaust gas stream, as discussed above. Thus, it is likely that costs for SCR at gas-fired turbines are lower than the cost estimates in the 1999 DOE report and the NESCAUM 2000 Status Report. Indeed, in 2015, the SCAQMD in California collected SCR cost information from vendors for 20 non-refinery, non-power plant gas turbines including turbines used in gas compression, and total installed costs ranged

[341] 1999 DOE Report, Appendix A at A-7 (Table A-6). Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). The annual costs due to the fuel penalty and ammonia use were decreased by 56% to reflect a 40% capacity factor, rather than the 91% capacity factor. Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines.

[342] *See* EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.

from $1.5 million to $2.9 million with the annual costs ranging from $63,000 to $727,000.[343] These costs reflected SCR achieving 95% control for those turbines with NOx rates of 40 ppm or higher and achieving 2 ppm for those turbines with NOx rates lower than 40 ppm.[344] The cost basis of these costs is not identified, but presumably the costs are from the 2010-2015 timeframe.[345] In 2019, SCAQMD ultimately determined it was cost effective to require SCR retrofits as BARCT for non-refinery, non-power plant combustion turbines. SCAQMD required gas turbines of capacities 0.3 MW and larger that power compressor stations to install retrofit NOx controls to meet a NOx limit of 3.5 ppmv at 15% oxygen and required other gas turbines, such as those used for power generation, to meet a NOx limit of 2.5 ppmv.[346] These limits are required to be met by 2024.[347] Other California air districts have adopted NOx limits for existing simple cycle gas turbines that reflect installation of SCR with NOx limits ranging from 2.5 to 9 ppm.[348] While several of these air districts limits were based on SCR applied to turbines of 10 MW capacity or greater, the SJVAPCD in California adopted NOx limits in the range of 5 to 9 ppmv for gas turbines in 2007 that were based on the installation of SCR, with the higher limits for turbines with capacities between 0.3 MW and 10 MW.[349]

The use of SCR presents several non-air quality and energy impacts, most of which are accounted for in the annual operating costs. Those impacts include the following:

- Parasitic load of operating an SCR system, which requires additional energy (fuel use and electricity) to maintain the same steam output at the boiler.[350]
- The spent SCR catalyst must be disposed of in an approved landfill if it cannot be recycled or reused, although it is not generally considered hazardous waste.[351] The use of regenerated catalyst can reduce the amount of spent catalyst that needs to be disposed of.[352]

[343] SCAQMD, Preliminary Draft Staff Report, Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM, July 21, 2015, at 183, *available at*: https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/pdsr-072115.pdf?sfvrsn=2.
[344] *Id.* at 182.
[345] It is assumed the cost data were collected before 2014. *See* November 26, 2014 report entitled "NOx RECLAIM BARCT INDEPENDENT EVALUATION OF COST ANALYSIS PERFORMED BY SCAQMD STAFF FOR BARCT IN THE NON-REFINERY SECTOR," available on SCAQMD's website at https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/noxreclaimbarct-nonconf-nonrefinery_112614.pdf?sfvrsn=2.
[346] *See* Rule 1134(d)(4), Table II, *available at*: http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1134.pdf.
[347] *Id.*
[348] These other California air districts that adopted NOx limits for gas-fired combustion turbines in the 2.5 to 9 ppm range include Sacramento AQMD, Bay Area AQMD, San Joaquin AQMD, Ventura County AQMD, and Yolo Solano AQMD. Further, it must be noted that while a 9 ppmv NOx limit can be met with ultra-low NOx combustors at some turbines, SCR may be required at other units to meet such a NOx limit.
[349] *See* September 2007, SJVAPCD, Amendments to Rule 4703 (Stationary Gas Turbines), Initial Study and Negative Declaration, at 5, *available at*: https://www.valleyair.org/notices/Docs/priorto2008/08-08-07/Negative%20Declaration.pdf.
[350] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf pages 15-16, and 48.
[351] *Id.* at pdf 18.
[352] *Id.* at pdf 18-19.

- If anhydrous ammonia is used, there would be an increased need for risk management and implementation and associated costs for receiving and storing the anhydrous ammonia.[353] If urea or aqueous ammonia is used as the reagent, the hazards from use of pressurized anhydrous ammonia do not apply.
- Excess ammonia can pass through the SCR (called "ammonia slip"), which then can react with sulfate or nitrate in the ambient air to form ammonium bisulfate or ammonium nitrate (i.e., fine particulate matter).[354] Typically, permitting authorities limit the amount of ammonia slip that may occur with SCR to limit the formation of ammonium bisulfate or ammonium nitrate.

There are typically not overarching non-air quality or energy concerns with this technology, and SCR technology is widely used at natural gas-fired combustion turbines. Most of the impacts mentioned above are considered as additional costs of using SCR and are taken into account in the SCR cost effectiveness analysis.

In terms of length of time to install SCR at gas-fired combustion turbines, a report prepared for the SCAQMD found that the typical installation time is about twenty-four months after an engineering firm begins the engineering design for the SCR, or a total of about 27–30 months.[355] These costs should all be included in the annual operating costs.

There are numerous examples of natural gas-fired combustion turbines with SCR installed for NOx control. Just in the electric utility industry, there are at least 310 gas-fired combustion turbines operating with SCR.[356] Clearly, SCR has been considered to be a cost effective NOx reduction technology for combustion turbines, including smaller compressor engines and those that power compressor stations, since at least 2007. Further, SCR is often combined with a combustion control like water injection or dry low NOx combustors, which optimizes the NOx emissions reductions and costs of control.

D. NOx EMISSION LIMITS THAT HAVE BEEN REQUIRED FOR EXISTING NATURAL GAS-FIRED COMBUSTION TURBINES

In 2005, EPA proposed a new NSPS for gas turbines, which was eventually promulgated at 40 C.F.R. Part 60, Subpart KKKK in 2006.[357] In promulgating Subpart KKKK, EPA updated the NSPS for gas turbines, which had last been reviewed for EPA's initial promulgation of NSPS for gas turbines in 1979.[358] As a starting point for considering the level of control that EPA considered to be cost effective as a retrofit control for existing gas turbines, it is instructive to review what EPA required in the NSPS Subpart KKKK

[353] Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.
[354] *See* 1999 DOE Report at 2-11.
[355] *See* ETS, Inc., NOx RECLAIM BARCT INDEPENDENT EVALUATION OF COST ANALYSIS PERFORMED BY SCAQMD STAFF FOR BARCT IN THE NON-REFINERY SECTOR, FINAL REPORT, NOVEMBER 26, 2014, at 17.
[356] Based on a search on EPA's Air Markets Program Database, *available at*: https://ampd.epa.gov/ampd/.
[357] 70 Fed. Reg. 8,314-8,332 (Feb. 18, 2005), 71 Fed. Reg. 38,482-38,506 (July 6, 2006).
[358] 44 Fed. Reg. 52,798.

for existing gas turbines that were modified on or after February 18, 2005. These standards are summarized in the table below. It is important to note that these standards were adopted for gas turbines that generate electricity or that are used for mechanical drive such as at a gas compressor station.

Table 28. NSPS Subpart KKKK NOx Control Requirements for Modifications to Existing Gas Turbines Occurring on or after February 18, 2005.[359]

Turbine Size/Range	Approximate Turbine size range, hp[360]	Subpart KKKK NOx limits for modified sources after 2/2005, ppmv	Control that NOx limit reflects
≤50 MMBtu/hr	≤6,850 hp	150	Probably none
>50 MMBtu/hr and ≤850 MMBtu/hr	>6,850 hp and ≤116,456 hp	42	Water/Steam Injection
>850 MMBtu/hr	>116,456 hp	15	DLNC

Thus, in 2005, EPA found that the cost of water or steam injection or dry low NOx combustion was cost effective for gas-fired turbines with capacity greater than 50 MMBtu/hr (or 116,500 hp, ~86 MW). In considering reasonable progress controls for gas-fired combustion turbines in the oil and gas industry in 2020, the EPA's NSPS NOx limits for sources modified in 2005 or later should be considered the "floor" of potential NOx controls to consider for an existing gas turbine meaning that, at the very minimum, this level of control should be considered cost effective for NOx reductions at gas turbines. However, installation of SCR, with or without water/steam injection or DLNC, would be the much more effective pollution control that should be evaluated in an analysis of controls to achieve reasonable progress, as it has been found to be a cost effective control for gas-fired combustion turbines.

Numerous states and local air agencies have adopted similar or more stringent NOx limits for existing gas turbines to meet, many of which have been in place for 10–20 years. In Table 29 below, we summarize those state and local air pollution requirements. Some of this information was initially obtained from EPA's 2016 CSAPR TSD,[361] which provided a summary of state NOx regulations for gas turbines and other NOx sources as of September 2014.[362] The current state/local requirements for those CSAPR states were confirmed by a review of the state and local rules. The CSAPR TSD focused on the rules applicable in the CSAPR states. EPA found that 9 CSAPR states did not have regulations limiting NOx emissions from existing gas turbines: Alabama, Arkansas, Indiana, Kentucky, Michigan, Mississippi, Oklahoma, South Carolina, and West Virginia.[363] We also reviewed California Air District rules, because several of those air districts have adopted the most stringent NOx emission limitations for existing gas turbines. Indeed, several air districts in California have adopted rules necessitating installation of SCR at

[359] *See* 40 C.F.R. Part 60m Subpart KKKK, Appendix, Table 1.
[360] Converted MMBtu/hr to hp based on following assumptions/conversion factors: Typical heat rate of simple cycle turbine of 9,788 Btu/kWh (per https://www.eia.gov/todayinenergy/detail.php?id=32572), and 0.7457 kW= 1 hp.
[361] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix B at 11-13.
[362] *Id.*
[363] *Id*. at 13.

virtually all simple cycle turbines. We reviewed some of the remaining states' regulations to determine whether there were NOx limitations for existing gas turbines. Specifically, we reviewed air regulations in New Mexico, Colorado, Utah, Montana, North Dakota, South Dakota, and Washington. It appears there are no NOx emission limits required for existing gas turbines in those states aside from what applies to modified gas turbines under the NSPS Subpart KKKK.

Table 29 is a summary of the NOx emission limits required of existing simple cycle gas-fired combustion turbines in state and local air districts across the United States. It is important to note that these are limits that, unless otherwise noted, currently apply to existing gas turbines. Unlike the NSPS standards of 40 C.F.R. Part 60, Subpart KKKK, gas turbines did not have to be modified to trigger applicability to these emission limits. Instead, these emission limits apply to existing gas turbines and generally require an air pollution control retrofit or an outright replacement of the gas turbine with a new turbine with integrated dry low NOx combustors. These state and local NOx limits were most likely adopted to address nonattainment issues with the ozone NAAQS and possibly also the $PM_{2.5}$ NAAQS. Nonetheless, what becomes clear in this analysis is that numerous states and local governments have adopted NOx regulations that require, at the very least, water or steam injection at existing gas turbines (or DLNC if available) to meet NOx limits of 42 ppmv,[364] and several state/local air agencies have adopted NOx limits in the range of 9–25 ppmv which require dry low NOx combustors or, if unavailable as a retrofit for the turbine type, SCR. Moreover, four California air districts and Georgia have adopted NOx limits for gas turbines that clearly require SCR, probably along with water injection or DLNC, to comply with NOx limits in the range of 2–5 ppmv. The lowest NOx limits are those recently adopted by the SCAQMD which require, by January 1, 2024, gas-fired combustion turbines of 0.3 MW or greater size to meet a 2.5 ppmv limit and compressor gas turbines to meet a 3.5 ppmv limit.

These limits were adopted generally to meet RACT and California BARCT requirements, and costs of controls are considered in making these RACT and BARCT determinations. However, RACT is not necessarily as stringent as BARCT. RACT is generally defined as: "devices, systems, process modifications, or other apparatus or techniques that are reasonably available taking into account: (1) The necessity of imposing such controls in order to attain and maintain a national ambient air quality standard; (2) The social, environmental, and economic impact of such controls."[365] BARCT, on the other hand, is defined as "an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."[366] BARCT is similar to a BACT determination under the federal PSD program, but it evaluates controls to be retrofit to existing sources, rather than applying to new or modified sources.

[364] Even some of the NOx limits in Table 29 that are higher than 42 ppmv may require water or steam injection to meet the limit.
[365] 40 C.F.R. § 51.100(o).
[366] HSC Code § 40406 (California Code), *available at:* https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=40406.&lawCode=HSC.

Table 29. Summary of State/Local Air Agency NOx Emission Limits for Existing Simple Cycle Gas-fired Combustion Turbines that Require NOx Pollution Controls[367]

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
CA – Sacramento Metro AQMD[368]	Rule 413.301.3	>0.3 MW or 3 MMBtu/hr (RACT)	42
	Rule 413.302.1	<2.9MW or >2.9 MW but <877 hrs/yr (BARCT[369])	42
		>877 hrs/yr & 2.9-10 MW (BARCT)	25
		>877 hrs/yr or >10 MW without SCR (BARCT)	15
		>877 hrs/yr or >10 MW with SCR (BARCT)	9
CA – Bay Area AQMD[370]	Regulation 9-9-301 Effective 1/1/2010:	5-50 MMBtu	42 ppmv or 2.12 lb/MWhr
		>50-150 MMBtu/hr & no retrofit available	42 ppmv or 1.97 lb/MWhr
		>5-150 MMBtu/hr & Water/Steam Injection Enhancement available	35 ppmv or 1.64 lb/MWhr
		>50 150 MMBtu/hr & DLNC available	25 ppmv or 1.17 lb/MWhr
		>150- 250 MMBtu/hr	15 ppmv or 0.70 lb/MWhr
		>250-500 MMBtu/hr	9 ppmv or 0.43 lb/MWhr
		>500 MMBtu/hr	5 ppmv or 0.15 lb/MWhr
		<877 hrs/yr & 50-250 MMBtu/hr	25 ppmv or 1.97 lb/MWhr
		250-500+ MMBtu/yr	25 ppmv or 1.17-0.72 lb/MWhr

[367] This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules, but the authors recommend that readers check each specific rule for the details of how the rule applies to RICE units, and in case of any errors in this table.

[368] http://www.airquality.org/ProgramCoordination/Documents/rule413.pdf.

[369] Best Available Retrofit Control Technology (BARCT) was to be met by May 31, 1997.

[370] http://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-9-nitrogen-oxides-and-carbon-monoxide-from-stationary-gas-turbines/documents/rg0909.pdf?la=en.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
CA-SCAQMD[371]	Rule 1134 Effective 12/31/95:	>0.3-2.9 MW	25 (reference limit) x EFF/25%[372]
		2.9-10.0 MW	9 (reference limit) x EFF/25%
		2.9-10.0 MW (no SCR)	15 (reference limit) x EFF/25%
		>10.0 MW	9 (reference limit) x EFF/25%
		>10.0 MW and no SCR	12 (reference limit) x EFF/25%
	By 1/1/24:	>0.3 MW	2.5
		Compressor gas turbine	3.5
CA – SJVAPCD[373]	Rule 4703 Tier 3 limits[374]	>0.3 MW to <3 MW	9
		3-10 MW pipeline gas turbine	8 (steady state) and 12 (non-steady state)
		>3-10 MW & <877 hrs/yr	9
		>10 MW & <200 hr/yr	25
		3-10 MW & >877 hrs/yr and >10 MW and 200-877 hrs/yr	5
		>10 MMW	3-5[375]
	Rule 74.23	0.3-2.9 MW	42

[371] http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1134.pdf.

[372] EFF = gas turbine efficiency, which can never be less than 25%. In other words, this multiplier allows a higher ppm limit than the reference limit if a turbine is more efficient than 25%.

[373] https://www.valleyair.org/rules/currntrules/r4703.pdf.

[374] Note that NOx limits reflective of water/steam injection, DLNC, and/or SCR have been in effect in San Joaquin Valley since 2000. Compliance with the Tier 3 limits was required between 2009-2012.

[375] Tier 2 limits, that were to be complied with in 2005, require turbines greater than 10 MW and greater than 877 hours per year to meet NOx limits in the range of 3-5 ppmv. *See* Table 5-2 of San Joaquin AQMD Rule 4703. Tier 3 limit is 5 ppmv for turbines>10 MW but with operations between 200 hr/yr - 877 hrs/yr. *See* Table 5-3 of San Joaquin AQMD Rule 4703.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
CA – Ventura County APCD[376]	Currently proposed revisions: By 1/1/24:	2.9-10.0 MW	25 x EFF/25
		>10.0 MW w/SCR	9 x EFF/24
		>10 MW w/o SCR	15 x EFF/25
		>4.0 MW & <877 hrs/yr	42
		All turbines	2.5
CA – San Diego APCD[377]	Rule 69.3.1	≥1.0 & <2.9 MW	42
		≥2.9 & <10.0 MW	25 x EFF/25
		≥10.0 MW w/o installed post combustion air pollution controls	15 x EFF/25
		≥10.0 with installed post-combustion air pollution controls	9 x EFF/25
CA-Yolo Solano AQMD[378]	Rule 2.34	0.3-2.9 MW & >877 hrs/yr AND >4 MW & less than 877 hrs/yr	42
		2.9-10 MW	25
		>10.0 MW	9
CA-Imperial County APCD[379]	Rule 400.1	>1 MW & >400 hr/yr	42
CA-Mojave Desert AQMD[380]	Rule 1159	>4MW & >877 hrs/yr	42
CA – Placer County APCD[381]	Rule 250	>0.3-2.9 MW&>877 hrs/yr	42

[376] http://vcapcd.org/Rulebook/Reg4/RULE%2074.23.pdf.
[377] https://ww3.arb.ca.gov/drdb/sd/curhtml/r69-3-1.pdf.
[378] https://ww3.arb.ca.gov/drdb/ys/curhtml/r2-34.pdf.
[379] https://ww3.arb.ca.gov/drdb/imp/curhtml/r400-1.pdf.
[380] https://ww3.arb.ca.gov/drdb/moj/curhtml/r1159.htm.
[381] https://ww3.arb.ca.gov/drdb/pla/curhtml/r250.pdf.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
		>4 MW & <877 hrs/yr	42
		2.9-10 MW	25
		>10.0 MW	9
CA – Tehama County APCD	Rule 4: 37	>0.3 MW (exempt if <4 MW&<877 hrs/yr)	42
TX/Houston Galveston Brazoria Ozone NAA[382]	30 TAC 117.310(a)(11)	Emission specs for mass emission cap and trade >10.0 MW	0.032 lb/MMBtu (9 ppmv)
	30 TAC 117.305(c)	Turbines >10.0 MW	42
	30 TAC 117.2010(c)(5)	1.0< &>10.0 MW	0.15 lb/MMBtu
TX/Dallas[383]	30 TAC 117.410(a)(5)	Emission Specs for 8 hr ozone Demo >10.0 MW	0.032 lb/MMBtu (9 ppmv)
	30 TAC 117.405(b)(3)	RACT >10,000 hp	0.15 lb/MMBtu
TX/Beaumont Port Arthur[384]	30 TAC 117.105 (c)	RACT>10.0 MW	42
GA (45 county area – ozone)	Rule 391-3-1-.02.(2)(nnn)1.(i) This appears to be an existing source requirement, with compliance required by 5/1/03	>25 MW, permitted <4/1/00	30
	Rule 391-3-1-.02.(2)(nnn)1.(iii)	>25 MW, permitted after 4/1/00[385]	6
WI (Milwaukee 7 county area)[386]	NR 428.22(1)(g)	>50 MW	25

[382] https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=5&ti=30&pt=1&ch=117&sch=B&div=3&rl=Y.

[383] https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=5&ti=30&pt=1&ch=117&sch=B&div=4&rl=Y.

[384] https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=105.

[385] This appears to be a new source requirement because compliance was required upon startup.

[386] https://docs.legis.wisconsin.gov/code/admin_code/nr/400/428/IV/22.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
		25-50 MW	42
NJ[387]	7:27-19.5(d)	>25 MMBtu/hr (case by case exemptions allowed for limits on water supply or no commercially available DLNCs)	2.2 lb/MWhr
	7:27-19.5(g)1 (Table 7)	HEDD Simple Cycle Gas Turbine (Power Generators) >15 MW	1.00 lb/MWhr
DE[388]	Title 7, §1112.3.5 (Table 3-2)	Gas turbines >15 MMBtu/hr	42
IL (Chicago are and Metro East area)[389]	Title 35 Part 217, §217.388a.1.E.	Gas turbines >2.5 MW (4,694 bhp)	42
PA[390]	Ch. 129.97(g)(2)(iv)	Gas turbines > 6,000bhp	42
MD (certain counties)[391]	COMAR 26.11.09.08G(2)	Turbines with Capacity Factor >15%	42
VA (northern VA)[392]	9VAC5-40-7430 (9VAC5-40-7410 requires compliance with RACT)	Turbines >10 MMBtu/hr RACT Limit	42
OH (Cleveland 8 county area)[393]	3745-110-03(E)(1)	>3.5 MW	42
CT[394]	22a-174-22e	Simple Cycle combustion turbines>5 MMBtu/hr	55

[387] https://www.nj.gov/dep/aqm/currentrules/Sub19.pdf.
[388] http://regulations.delaware.gov/AdminCode/title7/1000/1100/1112.shtml#TopOfPage.
[389] http://www.epa.state.il.us/air/rules/rice/217-subpart-q.pdf.
[390] http://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/025/chapter129/s129.97.html&searchunitkeywords=129.97&origQuery=129.97&operator=OR&title=null.
[391] http://mdrules.elaws.us/comar/26.11.09.08.
[392] https://law.lis.virginia.gov/admincode/title9/agency5/chapter40/section7430/.
[393] https://www.epa.ohio.gov/portals/27/regs/3745-110/3745-110-03_Final.pdf.
[394] https://www.ct.gov/deep/lib/deep/air/regulations/20160114_draft_sec22e_dec2015(revised).pdf.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
		Phase I limits (2018-2023) Ozone Season	50
MA[395]	310 CMR 7.19:(7)(a)1	>25 MMBtu/hr	65
NY[396]	6CRR-NY 227-2-4(e)	>10 MMBtu/hr	50
	6CRR-NY 227-3.4(a)(2) New Rule – compliance by 5/1/25[397]	>15 MW	25
LA (Baton Rouge 5 Counties & Region of Influence)[398]	LAC 33.03, Chapter 22, §2201.D.1 (Table D-1A)[399]	≥5-10 MW	0.24 lb/MMBtu (65 ppmv)
		≥10 <MW	0.16 lb/MMBtu (43 ppmv)
MO (St Louis Area)[400]	10 CSR 10-5.510(3)(C)1	>10 MMBtu/hr	75
NC (Charlotte 6 County Area)[401]	15A NCAC 02D.1408	>100 and ≤ 250 MMBtu/hr	75

As the above table shows, eleven state and local air pollution control agencies have adopted NOx emission limits for existing gas-fired simple cycle combustion turbines that reflect operation of SCR or possibly dry low NOx combustors (i.e., NOx emission limits in the range of 2.5 to 9 ppmv). SJVAPCD's NOx limits for pipeline gas compressor stations of 8 ppm (steady state) and 12 ppmv (non-steady state),

[395] https://www.mass.gov/files/documents/2018/01/05/310cmr7.pdf.
[396] https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).
[397] https://www.dec.ny.gov/regulations/116185.html.
[398] https://www.deq.louisiana.gov/resources/category/regulations-lac-title-33.
[399] These are emission factors, used in setting facility emission caps.
[400] https://www.sos.mo.gov/cmsimages/adrules/csr/current/10csr/10c10-5.pdf.
[401] https://files.nc.gov/ncdeq/Air%20Quality/rules/rules/D1408.pdf.

which were adopted in 2007, also reflect application of SCR.[402] The state of Georgia has stringent NOx limits for larger turbines in its 45-county ozone nonattainment area that also likely require SCR to comply with the NOx emission limits. These air agencies have thus found that the levels of NOx control listed in Table 29, including NOx limits as low as the 2.5–5 ppmv range of NOx emissions, are cost effective for existing simple cycle natural gas-fired combustion turbines.

NOx Limits Required for New Gas Turbines Used in the Oil and Gas Sector

Recently, there have been some examples of SCR being required in draft or final air construction permits for proposed new installations of compressor stations powered by gas-fired combustion turbines. Specifically, SCR was proposed to meet BACT requirements for the proposed Buckingham Compressor Station to be located in Virginia, with all four combustion turbines ranging from 6,276 to 15,900 hp to be subject to a NOx BACT emission limit of 3.75 ppmv at 15% oxygen.[403] In addition, SCR was proposed to be installed at the Charles Compressor Station to be located in Maryland,[404] the Northampton Compressor Station to be located in North Carolina,[405] and the Marts Compressor Station to be located in West Virginia.[406] These draft and final permits provide additional evidence of states and companies finding SCR to not be a cost prohibitive control for a compressor station.

E. SUMMARY – NOx CONTROLS FOR EXISTING NATURAL GAS-FIRED COMBUSTION TURBINES

The above analyses and state/local rule data demonstrates that numerous state and local air agencies have found water/steam injection, dry low NOx combustors, and SCR as cost effective controls for natural gas-fired combustion turbines, with costs ranging from $128/ton to $13,500/ton (1999$) to

[402] *See* September 2007, SJVAPCD, Amendments to Rule 4703 (Stationary Gas Turbines), Initial Study and Negative Declaration, at 5, *available at*: https://www.valleyair.org/notices/Docs/priorto2008/08-08-07/Negative%20Declaration.pdf. The fact that these limits require SCR to meet is reflected in permits for two compressor stations – the Wheeler Ridge Compressor Station and the Kettleman Compressor Station. *See* March 25, 2015 Title V Permit for Southern California Gas Co. Wheeler Ridge Compressor Station, *available at*: https://www.valleyair.org/notices/Docs/2015/03-25-15_(S-1134792)/S-1134792.pdf; February 5, 2018 Title V Permit for Pacific Gas and Electric Company – Kettleman Compressor Station, *available at*: http://www.valleyair.org/notices/Docs/2018/2-5-18_(C-1161601)/C-1161601.pdf.

[403] *See* January 9, 2019 Registration No. 21599, *available at*: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-for-buckingham-county-compressor-station-vacated.

[404] *See* Draft Permit for Dominion Energy Cove Point – Charles Station, *available at*: https://mde.maryland.gov/programs/Permits/AirManagementPermits/Documents/Dominion%20Charles%20Station%20draft%20ptc%20conditions%20for%20compressor%20station2018.pdf. It is not clear whether the final air permit has been issued yet for this facility.

[405] *See* Air Permit No. 10466R00, issued February 27, 2018, *available at*: https://edocs.deq.nc.gov/WaterResources/PDF/bf820b89-33eb-4cf9-bf89-2d6fb31b7418/Final%20Permit%20Northampton%20Compressor%20Station.pdf.

[406] *See* Permit No. R13-3271, issued July 21, 2016, *available at*: https://dep.wv.gov/daq/Documents/July%202016%20Permits%20and%20Evals/041-00076_PERM_13-3271.pdf.

meet NOx limits ranging from 42 ppmv down to 2.5 ppmv. Further, it is notable that, in the rules summarized above in Table 29, the primary exemptions or higher allowable NOx limits for low use turbines are those that operate at 10% or lower annual capacity factors (i.e., less than 877 hours/year), although there are several California districts with no exemptions for low capacity factor turbines. In addition, although there are some states that limited applicability of NOx emission limits to larger turbines (e.g., greater than 10 MW (or greater 13,500 hp or 100 MMBtu/hour)), there are several states and local air pollution control agencies that set NOx limits requiring NOx controls for turbines smaller than 10 MW. In fact, several California districts set a NOx limit reflective of water or steam injection (i.e., 42 ppmv) for turbines as small as 0.3 MW.

As states evaluate the level of NOx control to require at gas-fired combustion turbines associated with the oil and gas industry to make reasonable progress towards the national visibility goal, costs of NOx control should not be a significant consideration in the decision of what NOx emission limits to require existing natural gas-fired combustion turbines to meet, as there are ample examples of existing gas-fired combustion turbines being required to incur similar costs of control. Indeed, SCR should be considered the control technology of choice for NOx removal at gas-fired combustion turbines of 0.3 MW size or larger, including those that operate compressor stations and/or that operate at lower capacity factors. Combustion turbines with SCR should be able to meet NOx limits in the range of 2.5 to 9 ppmv NOx. For those turbines for which SCR is not technically or economically feasible, DLNCs should be the next control technology with NOx emission limits achievable in the 7.5 to 25 ppm range. If DLNCs are not available for retrofit to the turbine model, water or steam injection should be considered for NOx control, which should enable the combustion turbine to meet NOx limits in the range of 25 to 42 ppmv. It also must be recognized that, in some cases, it may be more effective for NOx control — and more cost effective — to require replacement of existing gas-fired turbines with new turbines designed with state-of-the-art dry low NOx combustion controls, as such controls can achieve much lower NOx rates than water or steam injection and do not require water usage.

V. CONTROL OF VOC EMISSIONS FROM NATURAL GAS-FIRED COMBUSTION TURBINES

VOC emissions from natural gas-fired combustion turbines result from incomplete combustion. The same is true for CO emissions. The combustion conditions that favor lower NOx emission rates, such as lower temperature combustion, tend to result in less complete combustion and thus higher VOC as well as CO emission rates.

Similar to RICE units, NOx is emitted at much higher rates from uncontrolled natural gas-fired combustion turbines compared to VOC emissions, with uncontrolled VOC emissions about two orders of magnitude lower than NOx emissions according to EPA's AP-42 emission factor documentation.[407] On the basis of pounds of VOC emission per heat input, EPA's AP-42 emission factors indicate that natural

[407] EPA, AP-42, Section 3.1, Tables 3.1-1 and 3.1-2, *available at*: https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf.

gas-fired combustion turbines emit VOCs at a much lower rate that natural gas-fired RICE.[408] However, it must be noted that EPA's uncontrolled VOC emission factor has an emission factor rating of "D," which means tests are based on a generally unaccepted method and/or from a small number of facilities.[409] Regardless, the same control for VOC emissions from lean-burn RICE units – oxidation catalyst – applies to control of VOC emissions from natural gas-fired combustion turbines.

According to EPA, oxidation catalyst is typically used on combustion turbines to control CO emissions as well as HAP emissions – primarily formaldehyde.[410] Removal of VOCs is a co-benefit of oxidation catalyst at natural gas-fired combustion turbines. Data collected by CARB of emission test results at combustion turbines used for power generation that were equipped with oxidation catalysts, among other air pollution controls, showed VOC emission rates generally in the range of 1 to 3 ppmv at 15% oxygen.[411]

It is not clear that oxidation catalyst has been widely implemented at existing natural gas-fired combustion turbines. According to documentation for EPA's 2019 Risk and Technology Review for its Stationary Combustion Turbine NESHAP, a review of air permits for 719 turbines found 50 units using oxidation catalyst.[412] That said, the data collected by CARB in 2004 indicated 31 natural gas-fired combustion turbines using oxidation catalyst.[413]

In addition, oxidation catalyst has been recently proposed and required for new natural gas-fired combustion turbines used in the oil and gas industry. For example, in its permit application for the Weymouth Compressor Station to be located in Massachusetts, oxidation catalyst was proposed to be installed on a combustion turbine-driven compressor unit to reduce VOCs as well as to reduce CO and HAP to meet BACT. Oxidation catalyst has been proposed to be installed along with SCR at the proposed Buckingham Compressor Station to be located in Virginia,[414] the Charles Compressor Station to be located in Maryland,[415] the Northampton Compressor Station to be located in North Carolina,[416] and the

[408] Compare VOC emission factors from EPA's AP-42, Section 3.1, Tables 3.1-1 and 3.1-2 to EPA's AP-42, Section 3.2, Tables 3.2-1, 3.2-2, and 3.2-3.
[409] EPA AP-42, Introduction at 8-10.
[410] EPA, AP-42, Section 3.1, at 3.1-7.
[411] *See* CARB, Report to the Legislature, Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts, May 2004, Appendix A, *available at*: https://ww3.arb.ca.gov/research/apr/reports/l2069.pdf.
[412] *See* December 11, 2018 Memo from RTI International to Melanie King, EPA, at 3, in EPA's docket for its Risk and Technology Review for the Stationary Gas Turbine NESHAP, Docket ID EPA-HQ-OAR-2017-0688-0066, *available at*: www.regulations.gov.
[413] *See* CARB, Report to the Legislature, Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts, May 2004, Appendix A.
[414] *See* January 9, 2019 Registration No. 21599, *available at*: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-for-buckingham-county-compressor-station-vacated.
[415] *See* Draft Permit for Dominion Energy Cove Point – Charles Station, *available at*: https://mde.maryland.gov/programs/Permits/AirManagementPermits/Documents/Dominion%20Charles%20Station%20draft%20ptc%20conditions%20for%20compressor%20station2018.pdf. It is not clear whether the final air permit has been issued yet for this facility.
[416] *See* Air Permit No. 10466R00, issued February 27, 2018, *available at*: https://edocs.deq.nc.gov/WaterResources/PDF/bf820b89-33eb-4cf9-bf89-2d6fb31b7418/Final%20Permit%20Northampton%20Compressor%20Station.pdf.

Marts Compressor Station to be located in West Virginia.[417] These draft and final permits provide evidence of states and companies finding oxidation catalyst to be a cost effective control for a combustion turbine-powered compressor stations.

In summary, oxidation catalyst is an available air pollution control to reduce VOC emissions, as well as to reduce CO and HAP emissions, from natural gas-fired combustion turbines used in the oil and gas industry. States should consider oxidation catalyst when evaluating reasonable progress controls for natural gas-fired combustion turbines used in the oil and gas industry.

VI. CONTROL OF EMISSIONS FROM DIESEL-FIRED RICE

Compression-ignited (*i.e.*, diesel-fired) RICE units are used in oil and gas exploration, production, and transmission sectors. These types of engines are generally used in the oil and gas industry for on-site power generation, as well as to power or to drive drill rigs, drive hydraulic fracturing pumps, and to power other pumping and compression applications. According to EPA's Alternative Control Techniques Document for Stationary Diesel Engines (2010), many of the "stationary" diesel RICE (meaning engines that are not mobile) are designated for continuous power use or used in standby power applications.[418] Company data suggests that those engines used as standby or emergency generators are generally less than 300 horsepower (hp), and diesel engines used for onsite power generation are typically greater than 300 hp although this is not a firm cutoff for standby diesel generator capacities.[419] The size of diesel engines for drilling rigs are likely much larger. A 2014 drilling rig emission inventory prepared for the state of Texas found that the mechanical drill rig engine sizes ranged from 430 hp for vertical wells less than 7,000 feet deep to 1,094 hp for vertical wells greater than 7,000 feet deep.[420] The study also found that, in Texas, mechanical rigs (diesel engines) were used for 96% of shallow vertical wells (< 7,000 feet) and 80% of deep vertical wells (> 7,000 feet), whereas 86% of horizontal wells are drilled by electric rigs.[421] According to the Texas drilling rig report, the trend in new drilling rigs is mostly electric rigs especially for larger drilling rigs, meaning that diesel-fired electrical generating sets are used to power the drilling engines (rather than diesel engines driving the drilling engines).[422] The electrical rigs typically have three large identical diesel generators, with one of the three units designated for standby

[417] *See* Permit No. R13-3271, issued July 21, 2016, *available at*: https://dep.wv.gov/daq/Documents/July%202016%20Permits%20and%20Evals/041-00076_PERM_13-3271.pdf.

[418] EPA, Alternative Control Techniques Document: Stationary Diesel Engines, March 5, 2010, at 13, *available at*: https://www.epa.gov/sites/production/files/2014-02/documents/3_2010_diesel_eng_alternativecontrol.pdf [hereinafter referred to as "EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE"]. Note, this ACT document expands upon the 1993 and 2000 ACT documents to address pollutants other than NOx.

[419] *Id.*

[420] Eastern Research Group, Inc., 2014 Statewide Drilling Rig Emissions Inventory with Updated Trends Inventories, Final Report, Prepared for Texas Commission on Environmental Quality, July 31, 2015, at 5-4, *available at:* https://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5821552832FY1505-20150731-erg-drilling_rig_2014_inventory.pdf.

[421] *Id.* at 4-1.

[422] *Id.* at 3-1.

capacity.[423] The Texas inventory report indicates that the typical size of electric generators to power the electric rigs is 1,338 hp.[424] This report was specific to Texas, and other states may have a different mix of size engines used for different types and depth wells. Diesel engine pumps are also used in hydraulic fracturing ("fracking"). In 2016, fracking accounted for 69 percent of all new oil and gas wells, according to the Energy and Information Administration.[425] Diesel engines used to power hydraulic fracturing pumps are generally in the range of 1,000–1,500 hp, with 8 to 12 pumps necessary per well site (total of 20,000+ hp per well site).[426]

A. CONTROL OPTIONS FOR DIESEL-FIRED RICE

Uncontrolled diesel RICE emit several pollutants that can contribute to regional haze, including NOx, particulate matter (PM), SO2, and VOCs. In some cases, the pollutant controls used for one pollutant can negatively or positively affect control of another pollutant. For example, combustion modifications employed to reduce NOx emissions will tend to increase PM emissions and VOC emissions, and vice versa. Controlling SO2, which is achieved by use of ultra-low sulfur diesel (ULSD) fuel, will reduce PM emissions as well. Thus, it can be important to evaluate pollution controls for diesel RICE holistically.

In its 1993 Alternative Control Techniques Document for Stationary RICE, EPA described NOx controls for diesel RICE, including combustion modifications (injection timing retard) and add-on controls (SCR), as follows:

> Ignition timing retard delays initiation of combustion to later in the power cycle, which increases the volume of the combustion chamber and reduces the residence time of the combustion products. This increased volume and reduced residence time offers the potential for reduced NOx formation. … Achievable NOx reductions using IR is engine-specific but generally ranges from 20 to 30 percent. Based on an average uncontrolled NOx emission level for diesel engines of 12.0 g/hp-hr (875 ppmv), the expected range of controlled NOx emissions is from 8.4 to 9.6 g/hp-hr (610 to 700 ppmv). [427]

> Selective catalytic reduction applies to all CI engines and can be retrofit to existing installations except where physical space constraints may exist. … Based on an average uncontrolled NOx emission level of 12.0 g/hp-hr (875 ppmv) for diesel engines, the expected range of controlled NOx emissions is from 1.2 to 2.4 g/hp-hr (90 to 175 ppmv). … Limited emission test data show NOx reduction efficiencies of approximately 88 to 95 percent for existing installations, with ammonia slip levels ranging from 5 to 30 ppmv.[428]

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[423] *Id.*

[424] *Id.* at 5-4.

[425] https://www.eia.gov/todayinenergy/detail.php?id=34732.

[426] *See*, e.g., Solar Turbines, Turbomachinery Considerations in Drilling and Fracturing, Gas Electric Partnership 2013, at 7-8, *available at:* http://www.gaselectricpartnership.com/hReinerKurzTurboMachinery.pdf.

[427] EPA 1993 Alternative Control Techniques Document for RICE at 2-5 and 2-22.

[428] *Id.*

Compression-ignition diesel-fueled engines operate lean, meaning there is excess air during combustion. And while the application of similar control techniques can differ for spark-ignition (gas-fired) and compression-ignition (diesel-fired) engines, according to EPA's 1993 Alternative Control Techniques Document for RICE, the: (1) process; (2) application considerations; (3) performance factors; and (4) potential NOx emissions reductions for SCR applications with diesel engines are similar to those for natural gas applications.[429]

In its 2010 Alternative Control Techniques Document for Stationary Diesel RICE, EPA discusses combining SCR with a particulate filter to reduce both NOx and PM emissions.[430] EPA describes diesel particulate filters (DPF) and catalyzed diesel particulate filters (CDPF) as follows:

> [DPF and CDPF] emission control technologies are designed to remove PM from the diesel engine exhaust stream using a wall flow filter material in which the exhaust gas must pass through a ceramic wall. In addition to PM, the catalyst in the CDPF also reduces emissions of [Total Hydrocarbons (THC)] and CO. … CARB reports PM emission reductions of 85 to 97 percent for various types of verified DPF or CDPFs. The EPA has verified DPF and CDPF systems that achieve up to 90 percent reduction. In addition to the PM reductions, the CDPF filter also reduces emissions of CO and THC by 90 percent but requires sufficient exhaust temperatures to facilitate regeneration by the catalyst. These reductions have been verified by both the CARB and EPA diesel control technology verification programs.[431]

CDPFs are thus a control device for PM and also for VOCs (THC) and CO.

Stationary diesel engine exhaust emissions include SO_2 due to sulfur in fuel, although a smaller percentage of the sulfur in fuel is converted to sulfates (particulate matter). At high temperatures, SO_2 can oxidize to form sulfates, contributing to further increases in PM emissions from engine exhaust. The use of ULSD fuel is essential in conjunction with exhaust treatment control technologies for reducing NOx and PM and is also, by itself, an effective and commonly applied way to reduce SO_2 emissions. Manufacturers require diesel engines equipped with CDPF to use ULSD fuel. EPA, in its 2010 Alternative Control Techniques Document for Stationary Diesel RICE, describes the use of ULSD as follows:

> EPA [] finalized NSPS for stationary CI engines that require all new stationary diesel engines to use ULSD in 2010. This ULSD fuel enables the use of aftertreatment technologies for new and existing diesel engines and can also by itself reduce emissions of criteria pollutants. The use of ULSD reduces the formation of sulfur oxides and particulate sulfates from the diesel engine exhaust. The reductions in PM are expected to be approximately 5 to 30 percent depending on the sulfur content of the fuel that is replaced. … It should be noted that ULSD is prevalent in the fuel pool today, including in some nonroad fuels that may not be labeled as such, and therefore may already be used in many stationary diesel engines.[432]

[429] EPA 1993 Alternative Control Techniques Document for RICE at 5-73.
[430] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 35.
[431] *Id.* at 32 and 34.
[432] *Id.* at 47 and 48.

In summary, while any one of these pollution controls can be used at a diesel RICE to control one pollutant, the co-benefits of using all of these controls together (ULSD, CDPF, and SCR) ensure the most effective control of NOx, PM, SO2, as well as CO and hazardous air pollutants.

B. EXISTING FEDERAL AIR REGULATIONS FOR DIESEL-FIRED RICE

The diesel engines that power and/or drive drill rigs and wellsite pumping operations may be considered to be nonroad engines (as opposed to stationary engines), if they meet the regulatory criteria to be considered a nonroad engine. According to EPA, a diesel engine is considered a nonroad engine if it is self-propelled or propelled while performing its function or portable or transportable (if it has wheels, skids, carrying handles, a dolly, trailer, or platform), although a nonroad engine becomes a stationary engine if it stays in one location for more than 12 months (or for a full annual operating period of a seasonal source).[433] EPA distinguishes between nonroad diesel engines and stationary diesel engines because the Clean Air Act directs EPA to set emission standards for new nonroad engines and generally does not allow states to set emission standards for nonroad engines except through a specific process outlined in Section 209 of the Clean Air Act.[434]

EPA has established emission limitations to decrease air emissions from nonroad diesel engines using a tiered approach, with the most stringent Tier 4 standards currently in effect for engine manufacturers. See 40 C.F.R. §§89.112, 1039.101, 1039.102. These are emission standards that the manufacturers must meet in their production and sale of diesel engines and for which they demonstrate compliance on a fleetwide basis. There have been four tiers of emission standards applicable to diesel RICE, with Tier 1 standards applying to engines constructed beginning in 1996-1998, Tier 2 standards applying in 2000-2004, Tier 3 standards applying in 2006-2008, and Tier 4 standards applying in approximately 2014 and beyond.[435] The emission standards do not specify any one pollution control technology that needs to be installed to meet the emission limitations. Instead, the standards set limitations on emissions. Generally, the Tier 1, 2, and 3 emission standards were met with advanced engine design, while the Tier 4 emission standards reflect application of CDPF and SCR.[436] These controls reduce PM and NOx emissions by over 90% from diesel RICE. In addition, the Tier 4 standards mandate that ULSD be used in Tier 4 engines.[437] This requirement also ensures reduced SO_2 emissions from diesel engines.

EPA has also established NSPS for stationary diesel engines (i.e., those diesel RICE not considered to be nonroad engines) in 40 C.F.R. Part 60, Subpart IIII. Those emission standards generally require engine manufacturers to meet the same emission standards applicable to nonroad diesel engines for the size and model year, beginning in model year 2007, for non-emergency engines of displacement below 10

[433] *See* EPA's "Understanding the Stationary Engines Rules," at https://www.epa.gov/stationary-engines/understanding-stationary-engines-rules. *See also* 40 C.F.R. §89.2.
[434] Section 209(e)(2) of the Clean Air Act.
[435] *See*, e.g., https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100OA05.pdf.
[436] *See*, e. g., EPA's Frequently Asked Questions from Owners and Operators of Nonroad Engines, Vehicles, and Equipment Certified to EPA Standards, available at https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100U8YP.pdf.
[437] 40 C.F.R. §1037.501(d)(2)

liters per cylinder.[438] Non-emergency engines of displacement higher than 10 liters per cylinder must generally meet the applicable emission standards for marine engines in 40 C.F.R. §94.8 which vary based on year of manufacturer and cylinder displacement.[439] Emergency engines that operate in emergency situations (like standby generators) do not have to meet the Tier 4 standards and instead must meet less stringent standards.[440]

The NSPS have separate requirements for owners or operators of stationary diesel engines that are generally not as stringent either in date of applicability or emission limits as the limits applicable to engine manufacturers. As summarized by an industry website, owners or operators of engines of pre-2007 model year must meet Tier 1 nonroad engine standards for engines less than 10 liters per cylinder and must meet Tier 1 marine standards for engines greater than or equal to 10 but less than 30 liters per cylinder.[441] For engines of 2007 model year or later, owners or operators of engines less than 30 liters per cylinder must buy engines that are certified to meet the NSPS standards applicable to manufacturers.[442] Owners or operators of 2007 model or later year engines greater than or equal to 30 liters per cylinder displacement must meet emission standards that vary depending on the year the engine was installed, with installations after January 1, 2016 having to meet emission limits reflective of application of DPF and SCR.[443]

Significantly, the NSPS do not apply to owners or operators of stationary diesel RICE that have been modified or reconstructed, nor do they apply to engines that were removed from one location and reinstalled at a new location.[444] Further, while the NSPS required by October 1, 2010 the use of ULSD fuel for those engines subject to the NSPS that are below 30 liters per cylinder displacement, engines with greater than or equal to 30 liters displacement that are subject to the NSPS are allowed to use 1,000 ppm sulfur content fuel.[445]

EPA has also adopted a National Emission Standard for Hazardous Air Pollutants for Stationary RICE (RICE NESHAP) that requires emission limits on CO that effectively also limit hazardous air pollutants and VOCs.[446]

[438] 40 C.F.R. §60.4201. Exceptions existing for engines operated in remote areas of Alaska and in marine offshore installations. 40 C.F.R. §60.4201(f).
[439] See 40 C.F.R. §60.4201.
[440] *See* 40 C.F.R. §60.4202.
[441] *See* https://dieselnet.com/standards/us/stationary_nsps_ci.php. *See also* 40 C.F.R. §60.4204(a).
[442] 40 C.F.R. §60.4204(b).
[443] 40 C.F.R. §60.4204(c).
[444] 40 C.F.R. §60.4208(i).
[445] 40 C.F.R. §60.4207.
[446] 40 C.F.R. Part 63, Subpart ZZZZ.

C. POLLUTION CONTROL UPGRADES OR RETROFITS FOR DIESEL-FIRED RICE

1. REPLACEMENT OF EXISTING DIESEL-FIRED RICE WITH TIER 4 ENGINES

Given that manufacturers are currently producing diesel RICE with integrated SCR and DPF to meet EPA's Tier 4 emission standards, it is likely the more cost effective option to consider the replacement of existing engines with new Tier 4 engines rather than requiring retrofitting of pollution controls. The emission reduction benefits from replacing existing diesel RICE with Tier 4 diesel RICE can be quite significant. It is difficult to directly compare the regulatory emission standards for Tiers 1–3 to the Tier 4 emission standards because the Tier 2 and 3 emission standards for NOx were based on the total of non-methane hydrocarbons (NMHC) plus NOx. EPA's 2010 Alternative Control Techniques Document for Stationary Diesel Engines summarized the NOx and PM emission rates for various size ranges and for the Tiers 1, 2, and 3, based on EPA's Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling – Compression Ignition (EPA 420-P-04-009), April 2004.[447] In the table below, we compare "Tier 0" (pre-1998) and EPA's Tier 1, 2, and 3 emission factors to the emission standards of the Tier 4 standards promulgated by EPA for specific size engines that fall within the various size ranges of applicability for EPA's nonroad emission standards.[448] The table below shows the NOx and PM emission rates expected for each of the four Tiers of diesel RICE rules, as well as NOx and PM emissions from diesel RICE manufactured before the EPA emission standards applied (i.e., pre-1998 or "Tier 0").

[447] *See* EPA's Alternative Control Techniques Guideline Stationary Diesel Engines, March 5, 2010 at 58 and 61 (Tables 5-2 and 5-3).
[448] *See* May 2004, EPA Regulatory Announcement, Clean Air Nonroad Diesel Rule, Table 1, *available at:* https://nepis.epa.gov/Exe/ZyPDF.cgi/P10001RN.PDF?Dockey=P10001RN.PDF.

Table 30. Comparison of NOx and PM Emission Rates for Various Engine Sizes and Tier Engines.[449]

ENGINE SIZE, HP	TIER ENGINE	NOX EMISSIONS, G/HP-HR	PM EMISSIONS, G/HP-HR
75	0	6.89	0.72
	1	5.58	0.47
	2	4.72	0.24
	3	3.00	0.30
	4	3.50[450]	0.02
174	0	8.39	0.40
	1	5.58	0.25
	2	4.00	0.13
	3	2.50	0.15
	4	0.30	0.01
600	0	8.39	0.40
	1	5.58	0.22
	2	4.10	0.13
	3	2.50	0.15
	4	0.30	0.01
750	0	8.39	0.40
	1	5.58	0.22
	2	4.10	0.13
	3	2.60	0.15
	4	2.60	0.075
1500 GEN SET[451]	0	8.9	0.40
	1	5.58	0.22
	2	4.10	0.13
	3	2.50	0.15
	4	0.5	0.02

As shown in the above table, the Tier 4 NOx limits reflect significant NOx reductions from each prior Tier engine for some engine sizes, except the smallest engines and the non-electrical generating set engines that are greater than 750 hp in size for which there is no different between Tier 3 and Tier 4 NOx emissions. The PM emissions, on the other hand, get increasingly more stringent with each Tier engine.

To determine the cost effectiveness of replacing an existing engine with a Tier 4 engine, one needs to know the costs of a Tier 4 engine. A 2010 analysis done by CARB collected cost data from equipment manufacturers for Tier 4 compliant Generator-Set Engines (or "Gen Sets") and determined the average cost per horsepower for a Tier 4 engine equipped with DPF and SCR.[452] Although this CARB analysis was

[449] Data from EPA's Alternative Control Techniques Guideline Stationary Diesel Engines, March 5, 2010 at 58 and 61 (Tables 5-2 and 5-3), and from May 2004, EPA Regulatory Announcement, Clean Air Nonroad Diesel Rule, Table 1.
[450] This limit applies to NMHC plus NOx. *See* https://nepis.epa.gov/Exe/ZyPDF.cgi/P10001RN.PDF?Dockey=P10001RN.PDF.
[451] Generator-set engines or "Gen Sets." These engines are used to operate an electrical generator or an alternator to produce electric power for other applications.
[452] CARB, Analysis of the Technical Feasibility and Costs of After-Treatment Controls on New Emergency Standby Engines at B-11, *available at:* https://ww3.arb.ca.gov/regact/2010/atcm2010/atcmappb.pdf.

for emergency standby engines, the cost data can provide a reasonable estimate of the capital costs to purchase diesel RICE meeting Tier 4 standards. This data was collected in 2010, and thus presumably reflects a 2010 $ cost basis.[453] CARB provided an average cost per horsepower of Tier 4 engines installed with DPF and SCR as follows:

Table 31. Average Cost Per Horsepower for Diesel RICE Meeting Tier 4 Final Requirements[454]

HP RANGE	$/HP FOR NEW ENGINES MEETING TIER 4 FINAL STANDARDS (2010 $)
50-174	$250
175-749	$184
750-1,206	$160
1,207-2,000	$155
>2,000	$125

With this average cost per horsepower data, the average cost effectiveness of replacing an older engine with a Tier 4-compliance diesel engine can be estimated. For the purpose of this cost effectiveness analysis, a 10-year useful life was assumed. The useful life for the emissions warranty guarantee period required in EPA's nonroad diesel engine rules is only 10 years.[455] While we contend that it is likely a RICE unit including such an engine with SCR installed, can have a useful life of 20 years or more, it is not as clear that the diesel particulate filter would have a life of more than 10 years.[456] Thus, for the purpose of this cost effectiveness analysis, a 10 year life of the new Tier 4 engines was assumed. A 5.5% interest rate was also assumed to be consistent with EPA's Control Cost Manual which recommends use of the bank prime interest rate.[457] The bank prime rate fluctuates over time, and the highest it has been in the past 5 years is 5.5%.[458] Reductions in NOx and PM emissions with the replacement of existing diesel RICE with Tier 4 engines were based on the emission factors reflected in Table 30 above. Given that the Tier 4 engines have significantly lower emissions of both NOx and PM, the total of NOx plus PM emissions reduced were considered in calculating cost effectiveness. The table below provides the cost effectiveness of replacing either a pre-1998 or a Tier 1, 2, or 3 engine with a Tier 4 engine. Calculations were done assuming that the engines operate at two different levels: 1,000 hours per year and 4,000 hours per year. EPA assumed 1,000 hours per year in cost analyses done for stationary diesel engines in its 2010 Control Techniques Document for Stationary Diesel Engines.[459] However, EPA also presented information from other sources indicating the average operating hours of diesel RICE are as high as 3,790 hours per year.[460] Thus, a 4,000 hour operating level was assumed to capture the upper end capacity factor of diesel RICE.

[453] *Id.* at B-11 and B-20.
[454] *Id.*, Table B-6.
[455] *See* 40 CFR 89.014.
[456] *See*, e.g., EPA Technical Bulletin, Diesel Particulate Filter General Information, *available at:* https://www.epa.gov/sites/production/files/2016-03/documents/420f10029.pdf.
[457] U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.
[458] *See,* e.g., https://fred.stlouisfed.org/series/DPRIME.
[459] *See* EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 56.
[460] *Id.* at 56 (Table 5-1).

Table 32. COST EFFECTIVENESS OF REPLACING EXISTING DIESEL RICE WITH TIER 4-COMPLIANT DIESEL RICE (2010$).

ENGINE SIZE, HP	ANNUALIZED COST OF NEW ENGINE[461]	ENGINE REPLACED WITH TIER 4	COST EFFECTIVENESS OF REPLACEMENT, 1,000 OPERATING HOURS/YR, $/TON of NOx+PM REMOVED (2010$)	COST EFFECTIVENESS OF REPLACEMENT, 4,000 OPERATING HOURS/YR, $/TON of NOx+PM REMOVED (2010$)
75	$2,488	Tier 0	$6,544/TON	$1,636/TON
		Tier 1	$9,921/TON	$2,480/TON
		Tier 2	$15,517/TON	$3,879/TON
		Tier 3	$107,526/TON	$26,882/TON
174	$4,247	Tier 0	$2,610/TON	$653/TON
		Tier 1	$4,011/TON	$1,003/TON
		Tier 2	$5,794/TON	$1,448/TON
		Tier 3	$9,466/TON	$2,367/TON
600	$14,647	Tier 0	$2,610/TON	$653/TON
		Tier 1	$4,034/TON	$1,009/TON
		Tier 2	$5,646/TON	$1,412/TON
		Tier 3	$9,466/TON	$2,367/TON
750	$15,920	Tier 0	$3,147/TON	$787/TON
		Tier 1	$6,164/TON	$1,541/TON
		Tier 2	$12,368/TON	$3,092/TON
		Tier 3	$256,280/TON	$64,070/TON
1500 GEN SETS[462]	$30,845	Tier 0	$2,255/TON	$564/TON
		Tier 1	$3,534/TON	$883/TON
		Tier 2	$5,026/TON	$1,256/TON
		Tier 3	$8,760/TON	$2,190/TON

Because the NOx emission rates of the various Tier 1–4 standards did not always decrease to the same extent for the smallest and the mid-size to large (non-Gen Set) engines, the cost effectiveness of replacing an existing engine with a Tier 4 engine of 75 hp and of 750 hp increases significantly between installing a Tier 4 engine to replace a Tier 0, 1, or 2 engine as compared to a Tier 3 engine. Also, as would be expected, it is generally more cost effective to replace an engine that operates 4,000 hours per year compared to one that operates 1,000 hours per year. In any event, as Table 32 demonstrates, it should at least be considered cost effective to replace a Tier 0 or Tier 1 engine with a Tier 4 engine of any size or operating hours. For engines in the range of 174 hp to less than 750 hp that operate 4,000 hours or more per year, it is also clearly cost effective to replace any tier engine with a Tier 4 engine, as it also is cost effective for large generator set engines.

[461] Based on the costs per horsepower given in Table 31 above and a capital recovery factor based on a 10-year life and a 5.5% interest rate of 0.132668.

[462] Generator sets > 1,200 hp have more stringent Tier 4 emission standards than other engines that are greater than 750 hp. *See* May 2004, EPA Regulatory Announcement, Clean Air Nonroad Diesel Rule, Table 1.

Although the above review focused on the cost effectiveness for the combined reductions of NOx plus PM, it is important to note that the EPA nonroad engine requirements also set emission limits on THC. Specifically, the Tier 4 standards set a THC emission limit that reflects an 87% reduction in THC compared to pre-1998 (Tier 0 levels). Further, only ULSD is to be used on Tier 4 engines. That is not only a legal requirement but, as discussed above, it is technically required by the manufacturer to ensure that the CDPF works effectively. The use of ULSD which is 15 ppm sulfur, compared to diesel fuel which may be 500 ppm sulfur, reflects a 97% reduction in SO2 emissions from diesel RICE. The increased costs for using ULSD are estimated to be $0.07 more per gallon, but the costs would be reduced to $0.04 per gallon due to anticipated savings because of decreased RICE maintenance with the use of low sulfur fuel.[463] Some states may already mandate the use of ULSD or it could be that ULSD is the only fuel available in some areas, so installation of a Tier 4 engine may not necessarily reduce SO2 emissions for all sources.

In terms of the non-air quality environmental and energy impacts associated with the replacement of an older engine with a Tier 4 engine, the impacts associated with the pollution controls could include increased fuel consumption due to reduced efficiency/parasitic load of SCR and CDPF and/or result in reduced power output. However, improvements in combustion efficiency that have been required and engineered into these newer engines also mean fuel savings that will make up for any parasitic loads, particularly for Tier 0 or Tier 1 engines replaced with Tier 4 engines. Other environmental impacts include solid waste disposal issues from spent catalysts. Further, the Tier 4 engines will require operator training and may result in increased maintenance, although the switch from higher sulfur diesel to ULSD which is mandated for use in Tier 4 engines will result in decreased maintenance. One likely benefit regarding maintenance associated with these controls when purchasing an engine with the NOx and PM controls built into the design as one package (as comparted to retrofitting an existing engine) is that the manufacturers will have a standard set of operating and maintenance procedures for each engine, whereas for a retrofit of SCR and/or CDPF to an existing diesel RICE, the operating and maintenance procedures will presumably need to be tailored to the specific make, model, and condition of the existing engine.

There are also other environmental benefits of replacing existing diesel engines with Tier 4 engines, particularly due to effects that increased engine efficiency and the use of a CDPF will have on reducing black carbon emissions from diesel RICE. Black carbon is very effective at absorbing solar energy. The black carbon particles in the atmosphere absorb solar energy and thus can warm the planet, although black carbon is considered a short-lived climate change pollutant.[464] And when the black carbon particles precipitate to surfaces of snow and ice, it reduces the reflecting power of the snow or ice which results in increased melting of snow and ice. The increased melting of the snow and ice results in a feedback loop with more land exposed to absorb, rather than reflect, solar energy, melting more snow and ice as well as permafrost that releases carbon trapped in the soils which further adds to climate change pollution.[465] Thus, the reduction in black carbon emissions by switching older diesel RICE with Tier 4 engines could have climate change benefits as well as visibility benefits.

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[463] *See* https://dieselnet.com/standards/us/nonroad.php.

[464] *See* https://oehha.ca.gov/epic/climate-change-drivers/atmospheric-black-carbon-concentrations; *see also* Cho, Renee, The Damaging Effects of Black Carbon, March 22, 2016, Earth Institute, Columbia University, *available at*: https://blogs.ei.columbia.edu/2016/03/22/the-damaging-effects-of-black-carbon/.

[465] *Id. See also* https://scied.ucar.edu/shortcontent/melting-ice-and-climate-change.

Given that manufactures were required to exclusively produce Tier 4 nonroad diesel engines by January 1, 2015, the Tier 4 engines should be readily available for purchase and installation, or be available in fairly short order. Thus, the replacement of an existing diesel RICE with a Tier 4 diesel RICE should presumably be able to be completed within six months to one year.

When EPA adopted the nonroad diesel engine emission standards, EPA envisioned that the nonroad diesel engine fleet would be comprised entirely of Tier 4 engines by 2030.[466] It is not clear whether the diesel RICE used in the oil and gas industry are on track to be operating on Tier 4 engines by 2030. As part of the process of evaluating controls to achieve reasonable progress towards the national visibility goal, States should evaluate the age and EPA emission compliance status (i.e., Tier) of existing diesel RICE operating within the oil and gas industry in the state. If states do not already collect such information, states should gather this information through required source inventory and/or source registration or licensure requirements.

It is clear that requiring replacement of existing diesel RICE with Tier 4 RICE engines is a cost effective control to reduce NOx and PM along with VOCs and SO_2 for many size engines in a range of operating hours. Requiring the replacement of existing diesel RICE with new Tier 4 engines along with requiring the use of ULSD fuel is the most readily implementable approach to reducing visibility-impairing emissions from diesel RICE.

It would be most effective to require use of Tier 4-compliant generator sets in conjunction with electric motors for all drilling operations, because large Gen Sets (which would be necessary to power electric drill rigs) are subject to much more stringent NOx limits than large diesel RICE (i.e., 0.5 g/hp-hr is the NOx limit for Tier 4 engines, compared to the 2.60 g/hp-hr NOx limit for large diesel RICE, as shown in Table 30 above). Indeed, the Superintendent of Carlsbad National Park has requested this approach as a mitigation measure for the Chevron U.S.A. Hayhurst Master Development Plan for which the western boundary of the project area was to be located only 17 kilometers from Carlsbad National Park in New Mexico. Specifically, the National Park Service stated that "[i]f this option were implemented, engines would meet the 0.5 g NOx/hp-hr [limit] and would reduce drilling and completion emissions by 90%."[467]

In summary, for stationary diesel RICE units, states should require the replacement of older existing engines with Tier 4 engines. For those diesel RICE that are considered nonroad engines, states should consider adopting emission requirements for diesel nonroad engines if California has adopted emission standards that have been approved by EPA under Section 209(e)(2) of the Clean Air Act, where the state adopts the same standards. Alternatively, a state can incentivize the replacement of existing nonroad engines with Tier 4 engines. Further, the state should otherwise encourage use of electric engines for drill rigs and the use of Tier 4 Gen Sets to power those electric engines, as that will result in the greatest reduction in NOx due to the lower emission limits that apply to Tier 4 Generator Set engines. States should evaluate all available options to, at the minimum, encourage replacement of older existing nonroad engines with Tier 4 engines.

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[466] *See*, e.g., EPA Progress Report on EPA's Nonroad Mobile Source Emissions Reductions Strategies, September 27, 2006, at 8, *available at:* https://www.epa.gov/sites/production/files/2015-11/documents/20060927-2006-p-00039.pdf.

[467] *See* August 29, 2016 Memorandum from Doug Neighbor, Superintendent, Carlsbad Caverns National Park, to Paul Murphy, Project Lead, Bureau of Land Management, Carlsbad Field Office, at 6.

2. REPLACEMENT OF EXISTING DIESEL-FIRED RICE WITH NATURAL GAS-FIRED RICE

A second option for reducing emissions from diesel RICE is to replace the engines with natural gas-fired or dual-fuel RICE. This was another mitigation measure recommended by the National Park Service to the Bureau of Land Management for the Chevron U.S.A. Hayhurst Master Development Plan. Specifically, the National Park Service stated: "[b]oth natural gas-fired and dual-fuel engines have proven to be feasible, cost effective options for drilling operations in various basins throughout the United States and Canada [fn omitted]."[468] The National Park Service gave numerous examples of companies employing natural gas-fired or dual-fuel drill rig engines, including "EQT, Apache Corporation, Chesapeake Energy, Statoil, Encana Corporation, Cabot Oil and Gas, Antero Resources, CONSOL Energy and Seneca Resources."[469] The National Park Service specifically highlighted Chesapeake Energy's move to "transition all of its hydraulic fracturing equipment to [liquefied natural gas]."[470]

The Four Corners Air Quality Task Force (4CAQTF) also evaluated this option of using natural gas-fired engines on the drill rigs in the Four Corners region.[471] The 4CAQTF found that this switch from diesel RICE to lean burn RICE engines would result in approximately a 91% reduction in NOx from use of Tier 0 diesel engines and approximately an 85% reduction in NOx from use of Tier 1 diesel engines, but this was based on an assumed NOx emission rate from lean burn natural gas-fired RICE of 2 to 3 g/hp-hr.[472] As discussed in Section II.D. and E. of this report, use of LEC or SCR at lean burn engines is cost effective for lean-burn RICE and could achieve NOx emission rates of no higher than 2 g/hp-hr and more likely 1 g/hp-hr or even lower. Use of natural gas-fired RICE instead of diesel RICE would also significantly reduce SO_2 and PM emissions. The 4CAQTF report found that use of natural gas-fired RICE may be less expensive than diesel RICE if natural gas is located within close proximity and able to be piped to the natural gas-fired RICE.[473] Diesel fuel generally needs to be hauled to the drill rig, thus replacement of diesel RICE with natural gas-fired RICE would also reduce mobile source tailpipe and fugitive emissions associated with transporting the diesel fuel. The 4CAQTF report gave one example of a natural gas-fired drill rig being utilized in the Jonah Field in Wyoming to indicate that the use of natural gas-fired drill rigs is a technically feasible option,[474] which is clearly the case given the number of companies cited by the National Park Service that are employing natural gas-fired or dual-fuel drill rig engines.[475] The 4CAQTF indicated a capital cost of up to $1.2 million dollars per rig for the retrofit.[476] Some of the negative impacts included that the use of natural gas-fired RICE would increase carbon monoxide emissions by

[468] *Id.* at 7.
[469] *Id.*
[470] *Id.*
[471] See Four Corners Air Quality Task Force, Report of Mitigation Options, November 1, 2007, at 61, *available at:* https://www.env.nm.gov/wp-content/uploads/sites/2/2016/11/4CAQTF_Report_FINAL.pdf.
[472] *Id.*
[473] *Id.*
[474] *Id.* at 62.
[475] *See* August 29, 2016 Memorandum from Doug Neighbor, Superintendent, Carlsbad Caverns National Park, to Paul Murphy, Project Lead, Bureau of Land Management, Carlsbad Field Office, at 7.
[476] *Id.*

approximately 175%, and also that there could be increased land disturbance regarding the installation of natural gas pipelines for delivery of fuel.[477]

In summary, replacement of diesel RICE with natural gas-fired RICE is a viable control option for addressing the visibility-impairing emissions from diesel RICE that states should consider in evaluating reasonable progress measures for diesel RICE units.

3. RETROFIT OF DIESEL-FIRED RICE WITH AIR POLLUTION CONTROLS

Another option to control emissions from stationary diesel RICE is to require retrofits of specific pollution controls. Provided below are cost effectiveness analyses for SCR retrofits and for DPF retrofits to diesel RICE.

a) RETROFITTING SCR TO EXISTING DIESEL-FIRED RICE TO REDUCE NOx

EPA's 2010 Alternative Control Techniques Document for Stationary Diesel RICE presented control costs for SCR and for CDPF retrofits at diesel RICE units. For SCR, EPA estimated capital costs at $98 per hp, based on industry data, and this included costs for the catalyst, reactor housing and ductwork, ammonia injection system, controls, and engineering and installation of the equipment.[478] EPA estimated annualized costs for SCR at $40 per hp, based on annualized capital costs and costs for operating/supervisory labor, maintenance, ammonia, steam diluent, and fuel penalty calculated using the EPA Control Cost Manual and based on 1,000 hours of operation per year.[479]

EPA's cost data for the 2010 Alternative Control Techniques document for Stationary Diesel RICE assume 90 percent reduction of NOx emissions from SCR, which should be readily achievable.[480] EPA estimates uncontrolled NOx emissions based on emission factors from modeling for the different tiers of EPA's exhaust emission standards for nonroad engines: (1) Tier 0 Standards (pre-1998); (2) Tier 1 Standards (1998-2003); (3) Tier 2 Standards (2004-2007); and Tier 3 Standards (2006-2010). As discussed above, the Tier 4 standards reflect the NOx control levels achievable with SCR, and thus it would not make sense for EPA to evaluate SCR retrofits for a Tier 4 engine.

The following table shows the cost effectiveness, based on EPA's cost data, of retrofitting SCR to an uncontrolled stationary diesel RICE and to a Tier 1, 2, or 3 diesel RICE operating 1,000 hours per year and 4,000 hours per year using EPA uncontrolled NO_x emissions estimates. EPA assumed 1,000 hours per year in cost analyses done for stationary diesel engines in its 2010 Control Techniques Document for Stationary Diesel Engines.[481] However, EPA also presented information from other sources indicating the average operating hours of diesel RICE as high as 3,790 hours per year.[482] Thus, a 4,000 hour operating level was assumed to capture the upper end capacity factor of diesel RICE. To estimate operating costs for operating at 4,000 hours per year, EPA's annual cost estimates for an engine

[477] *Id.* at 61-62.
[478] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 57.
[479] *Id.*
[480] *Id.*
[481] *See* EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 56.
[482] *Id.* at 56 (Table 5-1).

operating 1,000 hours per year were multiplied by a factor of four to estimate potential annual costs reflective of engines operating closer to 4,000 hours per year. For the cost effectiveness analysis presented herein, the SCR system was assumed to have a life of 20 years. EPA states that SCRs at boilers, refineries, industrial boilers, etc. have a useful life of 20-30 years.[483] To be consistent with EPA's statements on SCR and also considering the useful life of diesel RICE, this analysis will assume a 20-year life of the SCR. A 5.5% interest rate was used to be consistent with EPA's Control Cost Manual which recommends use of the bank prime interest rate.[484]

Table 33. Cost Effectiveness to Reduce NOx Emissions by 90% from Stationary Diesel RICE with SCR Operating 1,000 Hours per Year and 4,000 Hours per Year[485]

ENGINE SIZE, hp	ANNUALIZED COSTS OF SCR, 2005$	EMISSIONS STANDARD	COST EFFECTIVENESS OF SCR, 1,000 HOURS PER YEAR, 2005$	COST EFFECTIVENESS OF SCR, 4,000 HOURS PER YEAR, 2005$
75	$2,808	TIER 0	$5,474/ton	$4,575/ton
		TIER 1	$6,739/ton	$5,632/ton
		TIER 2	$8,021/ton	$6,703/ton
		TIER 3	$12,581/ton	$10,514/ton
238	$8,911	TIER 0	$4,500/ton	$3,761/ton
		TIER 1	$6,781/ton	$5,667/ton
		TIER 2	$9,430/ton	$7,881/ton
		TIER 3	$15,093/ton	$12,614/ton
675	$25,272	TIER 0	$4,500/ton	$3,761/ton
		TIER 1	$6,485/ton	$5,420/ton
		TIER 2	$9,207/ton	$7,694/ton
		TIER 3	$15,097/ton	$12,617/ton
1,000	$37,441	TIER 0	$4,497/ton	$3,759/ton
		TIER 1	$6,500/ton	$5,432/ton
		TIER 2	$9,204/ton	$7,692/ton
		TIER 3	$15,073/ton	$12,597/ton

[483] *See* EPA's Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80.
[484] U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.
[485] *See* EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 58, Table 5-2. Annualized costs of control were based on a 20-year life and a 5.5% interest rate. NOx emission reductions are based on 90% NOx removal efficiency, with uncontrolled emissions based on EPA estimates (EPA-420/P-04-09, 2004).

Lower cost data were reported by EPA in its 2000 Updated Information on NOx Emissions and Control Techniques for what it referred to then as 'modern SCR': "The vendor carried out a similar analysis for a 1,000 bhp diesel engine. For an engine operating 200 hours per year, the cost effectiveness was calculated at almost $4,000 per ton. For an engine operating 2,000 hours per year, the cost effectiveness dropped to less than $900 per ton."[486]

In its 1993 Alternative Control Techniques Document for RICE, EPA included a cost effectiveness analysis for diesel-fueled RICE with SCR operating 8,000 hours per year with costs as low as $690/ton for the largest engine sizes (4,000-8,000 hp). EPA noted costs of $1,000/ton or less for engines larger than 3,200 hp and costs of $3,000/ton or less for engines larger than 750 hp.[487]

It is clearly cost effective to retrofit SCR to diesel RICE units that emit NOx at levels similar to the older tier nonroad engines (*e.g.*, Tiers 0 or 1) even at low levels of operating hours per year. And, diesel RICE used in the oil and gas industry have been retrofitted with SCR to reduce NOx. For example, the state of Wyoming and the Bureau of Land Management coordinated with companies drilling in the Pinedale Anticline in western Wyoming to reduce NOx emissions from all drill rigs and, as a result, Shell Exploration and Production Company retrofitted 21 drill rigs with SCRs that have achieved 91-99% reduction in NOx emissions with low levels of ammonia slip (averaging 2-3 ppm).[488] There are several examples of successful SCR retrofits to diesel RICE, including for stationary diesel electrical generating sets and backup generators.[489]

[486] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 5-13 referencing the following document: Manufacturers of Emission Controls Association. *Urea SCR for Stationary IC Engines*. Slides from a presentation to the NESCAUM Stationary Source and Permits Committee. October 6, 1999.

[487] *See* EPA's 1993 Alternative Control Techniques Document for RICE at 2-38 and Table 2-14 at 2-42.

[488] *See* Manufacturers of Emission Controls Association, Case Studies of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 7 (Section 2.4), *available at:* http://www.meca.org/galleries/files/Stationary_Engine_Diesel_Retrofit_Case_Studies_1109final.pdf. *See also* Johnson Matthey, New system helps control NOx for Shell drill rigs, Pinedale Online, October 28, 2008, *available at:* http://www.pinedaleonline.com/news/2008/10/Newsystemhelpscontro.htm; and Johnson Matthey Catalysts, Application Fact Sheet, Case No. 801: Controlling NOx from Gas Drilling Rig Engine s with Johnson Matthey's Urea SCR System, *available at:* https://www.jmsec.com/fileadmin/user_upload/pdf/application_fact_sheets/engines/application_fact_sheet_801_-_shell_gas_drill_rig.pdf.

[489] *See* Manufacturers of Emission Controls Association, Case Studies of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 14, 5-7 and 12.

The environmental and energy impacts of SCR systems for diesel RICE include the following:

- 0.5 percent increase in fuel consumption for SCR and associated air emissions increases[490]
- 1 to 2 percent reduction in power output for SCR[491]
- Increased solid waste disposal from spent catalysts[492]
- If ammonia is used instead of urea (which is assumed to be the reagent used in the SCR cost analyses presented above), there would be an increased need for risk management and implementation and associated costs.[493] If urea or aqueous ammonia is used as the reagent, the hazards from the use of pressurized anhydrous ammonia do not apply. It is likely that urea is the most common reagent used in SCR for diesel RICE

SCR technology is widely used at many industrial sources. There are typically not overarching non-air quality or energy concerns with this technology, and many of the concerns are addressed in the cost analysis.

In terms of length of time to install SCR, EPA has estimated that it takes 28-58 weeks to install SCR at a diesel-fired (lean-burn) RICE unit.[494]

b) RETROFITTING CDPF TO DIESEL-FIRED RICE TO REDUCE PM AND VOCS

For CDPF, EPA estimated capital and annual costs in its 2010 Alternative Control Techniques Document for Stationary Diesel RICE based on cost equations developed for the RICE NESHAP. EPA's analysis was based on 2008 cost data from stationary diesel RICE retrofits. The following linear equation for annual cost includes annual operating and maintenance costs plus annualized capital costs based on a 7% interest rate and 10-year life of controls:

CDPF Annual Cost = 11.6 x ENGINE HP + 1,414 (2008$)

The capital cost equation for retrofitting a CDPF on a diesel engine was determined by EPA to be:

CDPF Capital Cost = 63.4 x ENGINE HP + 5,699 (2008$)

These relationships are derived from a data set that includes engines ranging from 40–1,400 hp.[495] EPA's cost estimates are based on 1,000 hours of operation per year.[496]

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[490] *See* EPA 1993 Alternative Control Techniques Document for RICE, 2-23 (Table 2-11).

[491] *Id.* at 2-23 (Table 2-11).

[492] Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for RICE Source Category at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP).

[493] Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.

[494] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls at 15.

[495] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 59.

[496] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 61.

EPA's cost data for the 2010 Alternative Control Techniques document for Stationary Diesel RICE assume 90 percent reduction of PM emissions from CDPF.[497] EPA estimates uncontrolled PM emissions based on emission factors from nonroad engine modeling for the different tiers of EPA's exhaust emission standards for nonroad engines: (1) Tier 0 Standards (pre-1998); (2) Tier 1 Standards (1998-2003); (3) Tier 2 Standards (2004-2007); and Tier 3 Standards (2006-2010). In 2004, EPA adopted Tier 4 Standards, which were to be phased-in from 2008 to 2015. The Tier 4 Standards require 90 percent reduction of PM and NOx emissions. According to EPA, "[t]hese emission reductions can be achieved through the use of control technologies, including advanced exhaust gas aftertreatment, similar to those required by the 2007-2010 standards for highway engines."[498]

The following table shows the results of a cost analysis, based on EPA's cost data, of retrofitting CDPF to an uncontrolled stationary diesel RICE operating 1,000 hours per year and 4,000 hours per year using EPA uncontrolled PM emissions estimates. For this cost analysis of CDPF, a 10-year life and 5.5% interest rate. As discussed above, while we contend that it is likely a RICE unit can have a useful life of 20 years, it is not as clear that the diesel particulate filter would have a life of more than 10 years.[499] Therefore, a useful life of a CDPF retrofit was assumed to be 10 years in determining annualized costs of CDPF. A 5.5% interest rate was also assumed to be consistent with EPA's Control Cost Manual which recommends use of the bank prime interest rate.[500] To estimate annual operating costs for operation of CPDF at 4,000 hours per year, EPA's annual cost estimates which were based on 1,000 operating hours per year were multiplied by a factor of four.

[497] *Id.*

[498] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 22.

[499] *See*, e.g., EPA Technical Bulletin, Diesel Particulate Filter General Information, *available at:* https://www.epa.gov/sites/production/files/2016-03/documents/420f10029.pdf.

[500] U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.

Table 34. Cost Effectiveness to Reduce PM Emissions by 90% from Stationary Diesel RICE with CDPF Operating 1,000 Hours per Year and 4,000 Hours per Year[501]

ENGINE SIZE, hp	ANNUALIZED COSTS OF CDPF, 2008$	EMISSIONS STANDARD	COST EFFECTIVENESS OF CDPF, 1,000 HOURS PER YEAR, 2008$	COST EFFECTIVENESS OF CDPF, 4,000 HOURS PER YEAR, 2008$
75	$1,670	TIER 0	$31,088/ton	$10,155/ton
		TIER 1	$47,467/ton	$15,505/ton
		TIER 2	$93,735/ton	$30,619/ton
		TIER 3	$74,837/ton	$24,445/ton
238	$2,955	TIER 0	$31,265/ton	$10,510/ton
		TIER 1	$49,665/ton	$16,696/ton
		TIER 2	$95,155/ton	$31,988/ton
		TIER 3	$83,321/ton	$28,010/ton
675	$6,397	TIER 0	$23,774/ton	$8,150/ton
		TIER 1	$43,343/ton	$14,860/ton
		TIER 2	$72,608/ton	$24,892/ton
		TIER 3	$63,467/ton	$21,759/ton
1,000	$8,958	TIER 0	$22,468/ton	$7,740/ton
		TIER 1	$40,960/ton	$14,110/ton
		TIER 2	$68,644/ton	$23,646/ton
		TIER 3	$59,960/ton	$20,654/ton

It must be noted that the higher cost effectiveness values for CDPF in comparison to SCR cost effectiveness values are due to the magnitude of PM emissions from diesel RICE being much lower than the NOx emissions from diesel RICE. The capital costs of CDPF range from $10,000 to $70,000, which is somewhat lower than the range of capital costs for SCR (which range from $7,300 to $100,000), and the annual operating costs of CDPF are significantly lower than the operating costs of SCR ($800-$3,200 per

[501] *See* EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 58, Table 5-2. Annualized costs of control were calculated assuming a 10-year life of controls and a 5.5% interest rate. NOx emission reductions are based on EPA's assumed 90% removal efficiency. Uncontrolled NOx emissions are based on EPA estimates (EPA-420/P-04-09, 2004).

year for CDPF compared to $2,200 to $29,000 per year for SCR).[502] Although CDPF can achieve greater than 90% reduction of PM, overall the tons of PM reduced with CDPF is an order of magnitude lower than the NOx emissions reduced with SCR, and thus the cost effectiveness of CDPF is much higher than the cost effectiveness of SCR.

To truly understand whether this control is considered cost effective, one has to evaluate whether similar sources have been required to install the control at similar costs. Indeed, there are several examples of diesel particulate filter systems being retrofitted to diesel RICE.[503]

As previously stated, the use of a CDPF requires the use of ULSD fuel. It should be noted that ULSD is prevalent in the fuel pool today, including in some nonroad fuels that may not be labeled as such, and therefore may already be used in many stationary diesel engines.[504] The use of ULSD which is 15 ppm sulfur, compared to higher sulfur diesel fuel which may be of 500 ppm sulfur content, reflects a 97% reduction in SO_2 emissions from diesel RICE. The increased costs for using ULSD are estimated to be $0.07 more per gallon, but the costs would be reduced to $0.04 per gallon due to anticipated savings because of decreased RICE maintenance with the use of low sulfur fuel.[505] EPA's 2010 Alternative Control Techniques Document for Stationary Diesel RICE estimated that using ULSD fuel would increase fuel costs by only $0.03 to $0.05 per gallon.[506]

The environmental and energy impacts of controls for stationary diesel RICE include the following:

- 1 to 2 percent fuel penalty for CDPF[507]
- Increased solid waste disposal from spent catalysts[508]

The CDPF will have an added benefit of reducing VOCs and associated air toxics. EPA has found that CDPF can reduce THC by 90 percent.[509] Thus, CDPF can be considered a top control technology for both PM and VOCs.

CDPF can be installed fairly quickly. EPA has indicated that diesel particulate filters can be installed in less than a day,[510] although this claim likely pertains to onroad diesel engines (i.e., trucks). Nonetheless, it is the same technology whether applied to a mobile source or a larger generating diesel RICE. It can be assumed that even taking into account time for engineering, design, ordering of parts, etc., the time to install a CDPF is likely under a year.

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[502] These costs reflect the range of capital and operating costs for the engine sizes evaluated in Tables 33 and 34, using EPA's SCR and CDPF cost calculations from its 2010 Alternative Control Techniques Document for Stationary Diesel RICE.
[503] *See* Manufacturers of Emission Controls Association, Case Study of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 6-14.
[504] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 47 and 48.
[505] *See* https://dieselnet.com/standards/us/nonroad.php.
[506] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 71.
[507] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 35.
[508] Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for RICE Source Category at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP).
[509] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 32 and 34.
[510] *See* https://www.epa.gov/sites/production/files/2016-03/documents/420f10028.pdf.

D. EXAMPLES OF STATE AND LOCAL AIR AGENCY RULES FOR EXISTING DIESEL-FIRED RICE

States and local air agencies have adopted NOx limits for diesel RICE, some of which have been in place for over 20 years. In Table 35 below, we summarize some of the stronger state and local air pollution requirements. Note that this is not a comprehensive list of state and local air regulations for diesel RICE.

California has adopted fleet-wide emission requirements for existing diesel "off-road" (i.e., non-road) diesel-fueled engines of 25 hp or greater (*see* Title 13 California Code of Regulations Sections 2449 through 2449.2), and EPA has authorized those rules under Section 209(e) of the Clean Air Act.[511] The goal of this program is to turnover nonroad diesel RICE to Tier 4 engines. The rule established in-use statewide emission performance standards that apply to any person owning and operating a nonroad diesel engine in California of 25 hp or greater. The fleet requirements phase in over time and require that fleets either meet fleet average emission targets or meet best available control technology (BACT). States may be able to adopt requirements like this for nonroad diesel RICE, pursuant to Section 209(e)(2) of the Clean Air Act.

Table 35 is a summary of the stronger NOx emission limits required of diesel RICE in states and local air districts across the United States. It is important to note that these are limits that generally do not apply to portable or nonroad engines, unless clearly stated otherwise. The most broadly applicable NOx limit required is approximately 1.10 g/hp-hr which applies in several air districts in California, although SCAQMD has adopted a more stringent NOx limit of 0.15 g/hp-hr. Those limits all likely reflect application of SCR to diesel RICE. These limits were adopted generally to meet RACT and BARCT (in California) and, as previously discussed, costs are taken into account in making these RACT and BARCT determinations. Thus, the fact that state and local air agencies have adopted emission limits reflective of SCR indicate that these agencies have found SCR to be a cost effective control to retrofit to existing stationary diesel RICE.

Table 35. State/Local Air Agency Diesel RICE Rules for NOx Emissions[512]

State/Local	Regulation	Applicability	NOx Limit and units[513] (equivalent g/hp-hr)
CA-Bay Area AQMD[514]	Reg. 9, Rule 8 Effective 1/1/2012:	51 to 275 bhp	180 ppmvd (2.47 g/hp-hr)
	>50 bhp &/or not Low Usage (<100 hrs/yr) &/or not registered as portable:	>175 bhp	110 ppmvd (1.51.g/hp-hr)

[511] 78 Fed. Reg. 58090-58121 (Sept. 20, 2013).
[512] This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules, but the authors recommend that readers check each specific rule for the details of how the rule applies to different units, and in case of any errors in this table.
[513] Emission limits that are in ppmvd are at @ 15% oxygen.
[514] http://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-8-nitrogen-oxides-and-carbon-monoxide-from-stationary-internal-combustion-engines/documents/rg0908.pdf?la=en.

State/Local	Regulation	Applicability	NOx Limit and units[513] (equivalent g/hp-hr)
CA-Mojave Desert APCD[515]	Rule 1160 (Amended 1/22/18)	>50 bhp &/or >100 hours/4 quarters, not portable, not subject to Airborne Toxic Control Measure, and only if located in the Federal Ozone Nonattainment area	80 ppmv (1.09 g/hp-hr)
CA-Sacramento AQMD[516]	Rule 412	>50 bhp with exemptions if portable, or if operated less than certain # of hours which vary based on rating of engine	80 ppmv (1.10 g/hp-hr) Alt Limit: 90% NOx reduction
CA-San Joaquin Valley APCD[517]	Rule 4702 Exemptions for <50 bhp, portable, or low use engines Non-EPA certified Compression Ignition Engines installed on or before 6/1/06. ---------- Applicable to EPA-certified CI Engines	>50 & ≤ 500 bhp	EPA Tier 3 or Tier 4 by 1/1/2010
		>500 & ≤750 bhp and < 1000 hrs/yr	EPA Tier 3 by 1/1/2010
		>750 bhp & < 1000 hrs/yr	EPA Tier 4 by 7/1/2011
		>500 bhp & ≥1000 hrs/yr	80 ppmv (1.10 g/hp-hr)
		EPA Tier 1 or 2 engine	EPA Tier 4 by 1/1/2015 or 12 years after install date, but no later than 6/1/2018.
		EPA Tier 3 or Tier 4 engine	Meet certified CI engine standard at time of installation
SCAQMD[518]	Rule 1110.2 As amended 11/1/2019	>50 bhp and not nonroad engines or portable (except portable generators that provide primary or supplemental power to a building, facility,	11 ppmvd (0.15 g/hp-hr)

[515] https://ww3.arb.ca.gov/drdb/moj/curhtml/r1160.pdf.
[516] http://www.airquality.org/ProgramCoordination/Documents/rule412.pdf.
[517] https://ww3.arb.ca.gov/drdb/sju/curhtml/r4702.pdf.
[518] http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1110-2.pdf.

State/Local	Regulation	Applicability	NOx Limit and units[513] (equivalent g/hp-hr)
		stationary source, or stationary equipment, which are not exempt from the NOx limit)	
CA- Ventura County AQMD[519]	Rule 74.9	>50 bhp & > 200 hrs/yr Does not apply to diesel engines with permitted capacity factor ≤ 15%	80 ppmvd (1.10 g/hp-hr) or 90% NOx reduction
TX- Houston-Galveston-Brazoria Area[520]	30 TAC 117.2010(c)(2) Emission Specs for 8hr ozone demo The following limits apply to "stationary engines" (stays at same location more than 12 months) operated more than 100 hours per year on average, that were placed into service after 10/1/01, that were installed, modified, reconstructed, or relocated on or after the date specified:	≥50hp & <100 hp, on or after 10/1/2007	3.3 g/hp-hr
		≥100 hp & <750 hp, On or after 10/1/2006	2.8 g/hp-hr
		≥750 hp, On or after 10/1/2005	4.5 g/hp-hr
		≥300 hp & < 600 hp, On or after 10/1/2005	2.8 g/hp-hr
TX- Dallas -Ft. Worth Area[521]	30 TAC 117.2110(3) Emission Specs for 8hr ozone demo The following limits apply to "stationary" diesel engines (stays at same location more than 12 months) operated more than 100 hours per year on average, that were placed into service after	≥50hp & <100 hp, on or after 3/1/2009	3.3 g/hp-hr
		≥100 hp & <750 hp, On or after 3/1/2009	2.8 g/hp-hr
		≥750 hp, On or after 3/1/2009	4.5 g/hp-hr

[519] http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.9.pdf.

[520] https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=2010.

[521] http://txrules.elaws.us/rule/title30_chapter117_sec.117.2110.

State/Local	Regulation	Applicability	NOx Limit and units[513] (equivalent g/hp-hr)
	3/1/09, that were installed, modified, reconstructed, or relocated on or after the date specified:	Alternative limit to above for units with an annual capacity factor of ≤.0383	0.060 lb/MMBtu
MI[522]	R 336.1818 Applies to stationary engines	>1 ton/day NOx engines per avg ozone control period day in 1995	2.3 g/bhp-hr
NY[523]	6 CCR-NY 227-2.4 (f)(3) Applies to stationary engines	≥ 200 bhp in a severe ozone nonattainment area or ≥400 bhp outside a severe NAA	2.3 g/bhp-hr
WI[524]	NR 428.22(1)(i) Exemptions for low operating unit engines or for engines certified to meet federal nonroad emission standards.	≥500 hp	2.0 g/bhp-hr
MO[525]	10 CSR 10-5.510(3)(D)3.B. Applies in St. Louis ozone nonattainment area, to installations with potential to emit ≥100 tpy that operate more than 750 hours annually or more than 400 hours during ozone season	≥1800 hp	2.5 g/hp-hr
OH[526]	OAC Chapter 3745-110-03(F)(3) Applies in counties around Cleveland ozone nonattainment	≥2,000 hp	3.0 g/hp-hr

[522] https://www.michigan.gov/documents/deq/deq-aqd-air-rules-apc-part8_314769_7.pdf.
[523] https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).
[524] http://docs.legis.wisconsin.gov/code/admin_code/nr/400/428.pdf.
[525] https://www.sos.mo.gov/cmsimages/adrules/csr/current/10csr/10c10-5.pdf.
[526] https://www.epa.ohio.gov/portals/27/regs/3745-110/3745-110-02_Final.pdf.

State/Local	Regulation	Applicability	NOx Limit and units[513] (equivalent g/hp-hr)
	area, to stationary engines at a facility with potential to emit ≥100 tpy		

E. SUMMARY – CONTROL OPTIONS FOR DIESEL-FIRED RICE UNITS

Based on all of the analysis provided above, there are several options for reducing visibility-impairing emissions from diesel-fired RICE units. These options are as follows, in order of most beneficial for reducing visibility-impairing pollutants from this source category:

1) Replace existing older diesel-fired engines with Tier 4 engines.

   Replacement of existing older diesel-fired RICE with Tier 4 engines is cost effective as shown in Table 32 above, and has the benefit of reducing NOx by 49% to 96% and PM by 81% to 97.5% (with the percentage reduction based on the emission rates the existing engines is complying with). Replacement of older diesel RICE with Tier 4 engines will also result in a reduction in VOC emissions, due to the VOC emission limits required of Tier 4 engines, and it will also reduce SO_2 emissions because ULSD fuel is required for Tier 4 engines.

   The cost effectiveness of replacing existing diesel-fired RICE varies based on the size of the engine being replaced (smaller engines and larger engines that are not electrical generating sets have less stringent Tier 4 emission limits, which impacts cost effectiveness for those engines, and also the annual operating hours impact cost effectiveness). In general, as demonstrated in Table 32 above, it is cost effective to replace a Tier 0 or Tier 1 engine with a Tier 4 engine for any size engine including for those engines operating on the lower end of annual operating hours.

   For drill rigs, it is most preferable from an air emissions perspective to replace existing older diesel-fired drill rigs with electric-motor drill rigs that are powered by a Tier 4 Electrical Generating Set. Tier 4 Electrical Generating Set engines greater than 1,500 hp are required to meet the lowest NOx and PM emission rates, significantly lower than large non-electrical generating engines (as shown in Table 30 above). Thus, installing electric drill rigs that are powered by Tier 4 electrical generating diesel RICE will result in the greatest reduction in visibility-impairing emissions if the only option is to continue to power the engines with diesel fuel.

2) Replace existing diesel-fired RICE with natural gas-fired RICE equipped with LEC or SCR. Replacing existing older diesel-fired RICE with natural gas-fired RICE, particularly those equipped with LEC or SCR, is also a very effective method for reducing NOx emissions by 85% to 95% and also significantly reducing if not eliminating SO_2 and PM emissions. While we did not calculate

the cost effectiveness of this control option, it is significant to note that the National Park Service has highlighted several companies that employ natural gas-fired or dual fuel drill rig engines, [527] and such engines are also being used in the Jonah Field in Wyoming.[528]

3) As a third option, existing diesel RICE can be retrofit with SCR and/or with CDPF. As demonstrated in Table 33, it is most cost effective to retrofit SCR to an existing Tier 0 or Tier 1 engine, and SCR can result in NOx emission reductions of 90% or more. And, as shown in Table 35, several California air districts have adopted NOx emission limitations that would require retrofitting of SCR to diesel RICE.
   In addition, CDPF can be retrofit to existing diesel RICE and achieve greater than 90% reduction of PM as well as reductions in VOC emissions. It must be noted that, overall, the tons of PM reduced with CDPF is an order of magnitude lower than the NOx emissions reduced with SCR, and thus the cost effectiveness of CDPF is much higher than the cost effectiveness of SCR- but that does not mean it is has not been considered a cost effective control. There are several examples of diesel particulate filter systems being retrofitted to diesel RICE.[529]

   Existing diesel-fired RICE should also be required to use ULSD fuel. EPA estimated that use of ULSD fuel would increase fuel costs by only $0.03 to $0.05 per gallon.[530] ULSD fuel is prevalent in the available fuels today and may already be required to be used in some areas/states. It is also required by the CDPF manufacturer to use ULSD fuel.

Thus, there are several options to cost effectively reduce emissions from diesel-fired engines used in the oil and gas industry. States must evaluate all available options for addressing this significant source of NOx, SO_2, PM and VOC emissions as part of their reasonable progress analysis. The most preferable options are those that address all of the visibility-impairing pollutants from this source category, with replacement of older diesel-fired engines with Tier 4 engines or replacing diesel-fired engines with natural gas-fired RICE equipped with LEC or SCR as the most effective emission limiting options.

VII. CONTROL OF NOx EMISSIONS FROM NATURAL GAS-FIRED HEATERS AND BOILERS

Natural gas-fired heaters and boilers are used in a variety of applications, including power generation and the production of process heat and steam. Boilers, reboilers, and heaters can be found throughout the production and processing segments of the oil and gas industry.

[527] *See* August 29, 2016 Memorandum from Doug Neighbor, Superintendent, Carlsbad Caverns National Park, to Paul Murphy, Project Lead, Bureau of Land Management, Carlsbad Field Office, at 7.
[528] See Four Corners Air Quality Task Force, Report of Mitigation Options, November 1, 2007, at 62.
[529] *See* Manufacturers of Emission Controls Association, Case Study of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 6-14.
[530] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 71.

In oil and gas production and processing, heaters can be used to aid in separation (e.g., heater-treaters, gas production units (GPUs), heated flash separator units),[531] to maintain temperatures within pipes / connectors (e.g., line heaters),[532] to maintain storage tank temperatures (e.g., tank heaters), and as regenerators / reboilers (e.g., glycol dehydrators, desiccant dehydrators).[533,534] These smaller integrated units are generally rated at less than about 2.5 million Btu per hour (MMBtu/hr) heat input.[535] Larger units can be found at gas processing plants, including steam boilers, hot oil heaters, fractionation column heaters, and other process heaters that range in size from a few MMBtu/hr to 100 MMBtu/hr heat input, or more.[536]

There are two basic ways of supplying combustion air to these types of external combustion units (i.e., two draft types): (1) natural draft (i.e., atmospheric units); and (2) mechanical or forced draft. In atmospheric units, the pressure difference between the hot stack gases and the cooler ambient air creates a draft, drawing supply air into the burners. These units are open to the atmosphere (i.e., non-sealed units). Mechanical draft units use a fan to introduce combustion air into the burners. Draft type can affect the level of excess air in the combustion chamber, and the resulting emissions from the unit (e.g., NOx emissions are generally lower in mechanical draft units by operating with lower excess air and improved flame characteristics).

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[531] Heater-treaters consist of a heater, free-water knockout, and oil/condensate and gas separator. GPUs consist of a heater and a separator to remove liquid from gas prior to further processing. Heated flash separators are equipped with small boilers to facilitate condensate removal through flashing.

[532] In-line heaters are used to maintain temperatures as pressure decreases, in order to prevent formation of hydrates. Note, in-line heaters can also be used to heat gas transmission lines further downstream in the oil and gas industry.

[533] Glycol dehydrators use glycol to remove water from the gas stream in order to prevent corrosion and freezing; small reboilers are used to regenerate the glycol. Dehydrators can be located at well pads, as well as at centrally-located gathering stations and processing facilities. Solid-desiccant dehydrators are generally used for large volumes of gas, e.g., downstream of a compressor station and use a heater to regenerate the desiccant.

[534] Dehydrator use varies depending on the moisture content of the gas; dry gas requires little dehydration. For example, according to the *Four Corners Air Quality Task Force Report of Mitigations* (Oil and Gas Section), "[i]n the [coal bed methane] areas of Colorado the gas is predominantly methane and the gas is relatively dry gas and requires little dehydration . . . Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required." *See* p. 90.

[535] *See* Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for Heater-Treater Source Category, completed for the 1st round RH plans [hereinafter referred to as "CDPHE RP for Heater-Treaters"], *available at*: https://www.colorado.gov/pacific/sites/default/files/AP_PO_Heater-Treaters_1.pdf; *also see* PA DEP PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) and the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. *See* p.52, *available at*: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

[536] Hot oil heaters, or thermal fluid heaters, are used in the oil and gas industry in combination with a heat exchanger to warm up a secondary fluid (gas or liquid). This can be useful in situations with certain temperature limitations (e.g., amine used to remove H_2S can degrade at high temperatures) or to prevent corrosive fluids from degrading heating coils. Fractionation column heaters are used at natural gas processing plants to separate out natural gas liquids for further use and can be larger than 10 MMBtu/hr.

Natural gas-fired external combustion units are sources of NOx, CO, VOC, and particulate matter emissions, with NOx the primary pollutant and the focus of this section. SO_2 emissions may also occur if the field-gas used to fire the heaters contains H_2S, which converts to SO_2 during combustion. While emissions from natural gas-fired heaters (e.g., heater-treaters, line heaters, tank heaters, and reboilers) may be relatively small on a unit level, compared to other combustion sources at oil and gas production and processing sites, these units may operate continuously throughout the year. And cumulative emissions from all of the heaters in use at an oil and gas production site or processing facility can be significant.

In its initial regional haze plan, Colorado completed a Reasonable Progress Evaluation for the Heater-Treater Source Category, including a NOx emission 4-Factor analysis for reasonable progress toward the national visibility goal.[537] In its evaluation, Colorado reported that, "the multitude of gas wells in Colorado (~26,000 by 2018) result in cumulative heater-treater NOx emissions that are projected to be the largest single area source category in Colorado by 2018."[538] Colorado projected NOx emissions in 2018 would reach close to 23,000 tons per year.[539]

Federal standards, in the form of NSPS and NESHAP, exist for industrial boilers and process heaters. The NSPS for industrial-commercial-institutional steam generating units are outlined in 40 C.F.R. Part 60, Subparts Db and Dc, and apply to boilers that are capable of combusting over 10 MMBtu/hr of fuel (burning coal, oil, natural gas, or wood). Subpart Db covers industrial-commercial-institutional steam generating units with heat inputs greater than 100 MMBtu/hr and that commenced construction after September 18, 1978. Subpart Dc covers smaller industrial-commercial-institutional steam generating units that commenced constructed after June 9, 1989. These NSPS include emission standards for sulfur oxides (SOx) and PM from burning fuels other than natural gas. In addition, there are no performance testing standards for boilers burning only natural gas. EPA also regulates VOC emissions from boilers and process heaters that are used as combustion control devices under Subpart OOOO and OOOOa through VOC emission reduction requirements, operating requirements, performance testing and monitoring requirements.[540] The NESHAP for industrial boilers, commercial and institutional boilers, and process heaters is outlined in 40 C.F.R. Part 63 Subpart DDDDD and controls mercury, hydrogen chloride, particulate matter (as a surrogate for non-mercury metals), and CO (as a surrogate for organic hazardous emissions) from coal-fired, biomass-fired, and liquid-fired major source boilers based on the maximum achievable control technology. However, these requirements will not address NOx emissions. In addition, all major source boilers and process heaters are subject to a work practice standard to periodically conduct tune-ups of the boiler or process heater.

When EPA adopts or revises Federal standards for a source category, EPA is establishing an emission standard applicable to all of the source types and variable fuels, operating conditions, etc. that exist for that source category. Thus, the NSPS are generally-applicable emission standards and not a source-specific evaluation of controls. It is necessary to evaluate if more broadly applicable and more stringent requirements and pollution controls are available to achieve reasonable progress towards the national

[537] *See* CDPHE RP for Heater-Treaters.
[538] *Id.* at 1.
[539] *Id.*
[540] *See, e.g.,* 40 C.F.R. Part 60 Subpart OOOOa §§ 60.5412, 60.5412a, 60.5413a, 60.5417a.

visibility goal, especially because the NSPS and NESHAP standards have not been re-evaluated in at least 8 years. Review of state regulations, particularly to address the NAAQS which require reductions in emissions from *existing* sources, is also necessary to fully evaluate controls for emission sources associated with oil and gas development to achieve reasonable progress towards the national visibility goal.

The information provided in this section for heaters and boilers reflects a review of the available pollution controls and techniques and associated emissions levels applicable to these source categories, along with data on cost of controls where available, non-air quality environmental and energy impacts, and the useful life of the emission source being evaluated.

Uncontrolled Emission Factors from Natural Gas-Fired External Combustion Units

NOx emissions from natural gas-fired heaters and boilers are generally expressed as emission rates in pounds per million Btu heat input (lb/MMBtu) or pounds per million standard cubic feet of gas (lb/MMscf) or as a concentration in parts per million by dry volume (ppmv or ppmvd). All concentrations expressed in ppmv are on a dry basis and corrected to 3% oxygen. The following emission factors are used in this section:

EPA Emission Factor
AP-42 Natural Gas Combustion (Section 1.4, last revised 1998)
Small Boilers <100 MMBtu/hr (Uncontrolled)…….100 lb/MMscf (0.098 lb/MMBtu)
Converted to lb/MMBtu based on fuel heating value of 1,020 Btu/scf

SCAQMD Emission Factor
Units ≤2 MMBtu/hr ……110 ppmv (0.136 lb/MMBtu)
SCAQMD derived an average emission rate to calculate baseline emissions for this size category in its implementation studies for Rule 1146.2 Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters. This factor accounts for units that are considerably older and also for ones that have not had continual maintenance and upkeep.[541]

[541] *See* SJVAPCD Final Draft Staff Report with Appendices For Proposed Amendments to Rule 4308 (November 5, 2009), B-4, *available at:* http://www.valleyair.org/board_meetings/GB/agenda_minutes/Agenda/2009/November/Agenda_Item_26_Nov_5_2009.pdf [hereinafter referred to as "SJVAPCD 2009 Final Draft Staff Report for Rule 4308"].

A. COMBUSTION MODIFICATIONS

Combustion modification—such as flue gas recirculation (FGR), low-NOx burners (LNB), and ultra-low NOx burners (ULNB)—reduce NOx formation by controlling the combustion process. The following is EPA's description of these combustion control techniques:

> Staging techniques are usually used by LNB and ULNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNB's create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNB's create a lean primary combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures. The secondary combustion zone is fuel-rich. Ultra-low-NOx burners use staging techniques similar to staged-fuel LNB in addition to internal flue gas recirculation. Flue gas recirculation returns a portion of the flue gas to the combustion zone through ducting external to the firebox that reduces flame temperature and dilutes the combustion air supply with relatively inert flue gas.[542]

Retrofitting natural gas-fired heaters and boilers with LNB was identified by EPA in 1998 as one of the two most prevalent control techniques in its AP-42 Emission Factor documentation, along with FGR.[543] EPA states that, "NOx emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NOx burners."[544] And EPA further states that, "[w]hen low NOx burners and FGR are used in combination, these techniques are capable of reducing NOx emissions by 60 to 90 percent."

CARB, in its 1991 RACT and BARCT determinations for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, also identified LNB as one of four control methods (along with FGR, SCR, and selective noncatalytic reduction (SNCR)).[545] CARB concluded that, for units ≥5 MMBtu/hr (and ≥90,000 therms annual heat input) a BARCT NOx limit of 30 ppmv (0.036 lbs/MMBtu) could be achieved by installing new burners with FGR, noting that some units would "need to install selective noncatalytic reduction or other emission control technology instead of flue gas recirculation due to particular unit design problems."[546] However, these determinations were from 1991, and the NOx removal capabilities of low NOx burners and similar combustion controls for NOx has greatly improved over time.

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[542] EPA-453/R-93-034 Alternative Control Techniques Document—NOx Emissions from Process Heaters (Revised), September 1993, p.2-6, *available at:* https://www3.epa.gov/ttncatc1/dir1/procheat.pdf [hereinafter referred to as EPA 1993 ACT for Process Heaters].

[543] EPA, AP-42, Section 1.4.4 (last revised 1998), *available at*: https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf.

[544] *Id.*

[545] CARB Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, July 18, 1991, p. 7 *available at:* https://ww3.arb.ca.gov/ractbarc/boilers.pdf [hereinafter referred to as "CARB 1991 Guidance"].

[546] CARB 1991 Guidance at 6.

For example, in 2018, California's SCAQMD concluded the following with regard to ULNB technology and its ability to meet very low NOx emission limits across a wide range of unit sizes:

> It was noted in the 2008 Rule 1146 and 1146.1 staff reports that there was clear evidence that these types of [ultra-low NOx] burners had been successfully retrofitted on boilers and heaters in the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) in their Rule 4306. Source tests that were conducted in conjunction with Rule 4306 showed a 98% compliance rate with a 9 ppm NOx limits using ultra-low NOx burners. In 2010, staff published a technology assessment report discussing the implementation assessment of ultra-low NOx burners subject to Rules 1146 and 1146.1. **The report concluded that the 9 ppm NOx limit can be achieved by ultra-low NOx burner systems for boilers and process heaters greater than 2 MMBtu/hour.** There were ultra-low NOx burners from 16 different manufacturers that could achieve the 9 ppm NOx compliance limit.[547]

In 2010, California's Sacramento Metropolitan AQMD (SMAQMD) determined, based on SCAQMD's rules for similar size sources and models being sold that meet SCAQMD limits, that ULNB technology was available to meet emissions limits for very small units, less than 1 MMBtu/hr.[548] Specifically, SMAQMD found that very small units less than 1 MMBtu/hr could meet a NOx limit equivalent to 20 ppmv:

> The proposed standards are technically feasible. The low NOx technology is commercially available and widely used. Additionally, these standards have already been adopted by the South Coast AQMD and the Bay Area AQMD, and except for the limits proposed for 2013 (which take effect for the SCAQMD in 2012), are already in effect in SCAQMD. As documented in the SCAQMD staff report for Rule 1146.2, as of 2006, 18% of the certification tests for units between 75,000–400,000 Btu/hr and 44% of the certification tests for units between 400,000 and 2,000,000 Btu/hr were already meeting the 14 ng/J (20 ppmv) standard. SCAQMD currently keeps a list of well over 100 certified models that are complaint with the standards in Rules 1146.2 and 1121.[549]

SMAQMD concluded that, "[t]he proposed emission limits are readily achievable through the use of low NOx burners."[550]

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[547] SCAQMD Draft Staff Report Rules 1146, 1146.1, 1146.2, and 1100, p. 2-2 [emphasis added], *available at:* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/rule-1146-1146.1-and-1146.2/dsr-1146-final.pdf?sfvrsn=6 [hereinafter referred to as "SCAQMD 2018 Draft Staff Report"].

[548] SMAQMD Staff Report Rule 414 Water Heaters, Boilers and Process Heaters Rated Less Than 1,000,000 Btu Per Hour, January 15, 2010, p. 5, *available at:* http://www.airquality.org/ProgramCoordination/Documents/Rule414%20StaffReport%20011510.pdf [hereinafter referred to as "SMAQMD 2010 Rule 414 Staff Report"].

[549] *Id.* at 16.

[550] *Id.* at 13.

In 2015, a Ventura County Air Pollution Control District (VCAPCD) analysis for amendments to its rules for boilers, steam generators, and process heaters ≥2 and <5 MMBtu/hr found:

> Ultra-low NOx burner systems can achieve less than 9 ppm NOx for boilers, steam generators, or process heaters without the use of Flue Gas Recirculation (FGR) systems. Source tests performed by the San Joaquin Unified Air Pollution Control District showed a 95 percent compliance rate with 9 ppm limits using ultra-low NOx burners. The average NOx concentration measured was 7 ppm.[551]

And as recently as April 2019, Santa Barbara County APCD concluded the following about the ability of ULNB technology to achieve lower NOx limits of between 9 and 12 ppm for units between 2–5 MMBtu/hr:

> The focus of this rule amendment is to lower the emission limits for new and modified natural gas and field gas units from 30 ppm to the 9-12 ppm NOx emission limits, beginning on January 1, 2020. To meet these lower standards, most boilers will have to be equipped with ultra-low NOx burners. Ultra-low NOx burners are designed to achieve low emissions while maintaining good flame stability and heat transfer characteristics. Furthermore, these burners may increase thermal efficiencies by reducing the amount of excess air needed for combustion. This has the added benefit of reducing fuel usage, which results in energy savings.
>
> For most systems, a blower will be required to mix the fuel and air prior to combustion. Even atmospheric boilers, where the burners are not totally enclosed, may still need a blower to premix the fuel and air. Due to the design criteria of these atmospheric boilers, it is only feasible to have them reach the 12 ppm NOx limit, as opposed to the 9 ppm limit for non-atmospheric boilers. It is possible to reach both the 9 and 12 ppm NOx limits without the use of Flue Gas Recirculation (FGR), yet some operators may still choose to use this technology.[552]

Thus, in rulemakings enacted in California air districts from 2015 to 2019, it was essentially deemed reasonable to impose a NOx emission limit of 9 ppm for natural gas-fired heaters and boilers with heat input capacities greater than or equal to 2 ppm. However, as will be discussed in Sections B. and F., even lower NOx limits have been required for heaters and boilers in some California Air Districts.

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[551] VCAPCD Staff Report Amendments to Rule 74.15.1 Boilers, Steam Generators and Process Heaters June 23, 2015, p. 4, *available at*: http://www.vcapcd.org/pubs/Rules/74151/201506/Staff-Report-Rule-74-15-JUNE-23-%202015.pdf [hereinafter referred to as "VCAPCD 2015 Staff Report"].

[552] Santa Barbara County APCD Draft Staff Report for Amended Rule 361. Boilers, Steam Generators, and Process Heaters (Between 2–5 MMBtu/hr); Amended Rule 342. Boilers, Steam Generators, and Process Heaters (5 MMBtu/hr and greater), April 22, 2019, p. 5, *available at*: https://www.ourair.org/wp-content/uploads/2019-05cac-r361-r342-att1.pdf [hereinafter referred to as "Santa Barbara County APCD 2019 Draft Staff Report"].

There are several emerging combustion technologies that demonstrate the potential for even lower levels of NOx without the use of post-combustion controls, such as SCR:

- SOLEX™ Burner is an emerging technology designed to achieve 5 ppm NOx.[553] This burner technology is available as a burner-only alternative to SCR for units "with heat releases between 1 MMBtu/hr and +20 MMBtu/hr."[554] It can be retrofit to existing units and fits traditional ULNB footprints.

- ClearSign Ultra Low NO_x Technology is designed to achieve sub 5 ppm NOx.[555] This technology is reportedly less costly than traditional ultra-low NOx controls with no FGR, lower fuel use, and can be retrofit to existing units. This technology has been installed on several units in SJVAPCD with more testing / demonstration needed:
    - Installation at two refinery heaters (burning natural gas, not refinery gas):
        - 15 MMBtu/hr heater
        - 8 MMBtu/hr heater
    - Installation at two natural gas-fired 62.5 MMBtu/hr oil field steam generators
    - Installation at six enclosed flares (thermal oxidizers)

- Altex Technology Corporation Near Zero NOx Burner has been applied to an 8 MMBtu/hr unit and is capable of achieving 5 ppm under some operating conditions.[556] This technology is being developed as an alternative to SCR for meeting NOx limits as low as 5 ppm for smaller units (e.g., in response to SCAQMD's consideration of a 5 ppm NOx limit for units ≥2 MMBtu/hr).[557]

1. COST EFFECTIVENESS EVALUATIONS FOR COMBUSTION MODIFICATION RETROFITS, REPLACEMENTS, AND UPGRADES

California Air Districts have long been regulating NOx emissions from boilers and process heaters, with CARB issuing RACT / BARCT guidance to Air Districts in 1991.[558] In its 1991 guidance CARB determined the cost effectiveness of LNB (in 1986$) for units as small as 3.5 MMBtu/hr and as large as 150 MMBtu/hr, as follows: (1) $500–$6,400/ton for units operating at a 50% capacity factor; and (2) $300–$4,000/ton for units operating at a 90% capacity factor.[559]

More recent and more detailed cost data are available from California Air Districts that have adopted, and continue to update, regulations for these sources. Based on a review of the various California Air

[553] John Zink Hamworthy Combustion, SOLEX™ Burner, *see:* https://www.johnzinkhamworthy.com/wp-content/uploads/solex-burner.pdf.
[554] *Id.*
[555] ClearSign https://clearsign.com/. Also see SJVAPCD presentation "ClearSign Ultra Low NOx Technology" November 7-8, 2017, *available at:* https://ww3.arb.ca.gov/enf/training/sympo/ppt2017/0830-b-scandura.pdf.
[556] California Energy Commission Report, *Near Zero NOx Burner*, July 2018, *available at:* https://ww2.energy.ca.gov/2018publications/CEC-500-2018-016/CEC-500-2018-016.pdf.
[557] *Id.*
[558] CARB 1991 Guidance.
[559] CARB 1991 Guidance Table 4. Note, CARB does not identify the underlying assumptions for annualized costs, life of controls, etc.

District rules and in researching vendor information, the source category of boilers and heaters should be subcategorized into three categories for assessing cost effectiveness and achievable NOx emission rates with combustion modifications: (1) Units > 20 MMBtu/hr (achieving NOx levels as low as 6 ppm); (2) Units >5 MMBtu/hr and ≤20 MMBtu/hr (achieving NOx levels as low as 6 ppm); and (3) Units ≤5 MMBtu/hr (achieving NOx levels of 9–20 ppm). Below, we evaluate cost effectiveness of combustion controls for each of these categories of boilers and heaters, based on cost analyses that local air agencies have relied on for regulating these units.

a) Units >20 MMBtu/hr

SJVAPCD is in the process of reviewing its rules for boilers and process heaters >5 MMBtu/hr and is proposing updates as part of its 2018 $PM_{2.5}$ Attainment Plan commitments to reduce NOx emissions.[560] SJVAPCD is considering lowering NOx limits for units >5 MMBtu/hr to levels ranging from 2–3.5 ppm.[561] As part of its control measure analysis, SJVAPCD analyzed the cost effectiveness of retrofitting units of varying sizes with ULNB to achieve a NOx level of 6 ppm, based on vendor cost data. We assume these data are in 2018$.

The SJVAPCD cost data for retrofitting existing units with ULNB includes detailed direct and indirect capital and operating costs for two unit size categories: (1) units >5 and ≤20 MMBtu/hr; and (2) units >20 MMBtu/hr.[562] For the larger size units (>20 MMBtu/hr), SJVAPCD notes that the retrofit may involve "upgrades to various systems such as fuel train to comply with up to date codes, and may involve upgrades to air intake fans, as these units require more air for the burner to operate at its optimum level."[563]

Table 36 below summarizes the total costs for retrofitting existing units >20 MMBtu/hr with ULNB, based on SJVAPCD vendor data, along with calculated annualized costs of the control, assuming a 5.5% interest rate and a 25-year life. Low NOx technologies should last the life of the emission unit. SCAQMD is currently assuming a 25-year life for refinery heaters and boilers.[564] And a review of the emission units in New Mexico permitted oil and gas sources such as gas processing plants show average ages of boilers and heaters of 30-35 years. Thus, we used a 25-year life as a minimum life for a heater or boiler controls in the cost effectiveness analysis, which seems more than justified. Table 36 presents the cost effectiveness of applying these low NOx technologies to existing units to reduce NOx emissions from uncontrolled levels to 6 ppm. Uncontrolled emissions are based on the EPA AP-42 uncontrolled

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[560] SJVAPCD Rules 4306 and 4320. *See*: https://www.valleyair.org/Workshops/public_workshops_idx.htm#12-05-19_ICE.

[561] SJVAPCD 2018 Plan for the 1997, 2006, and 2012 $PM_{2.5}$ Standards (November 15, 2018), Appendix C: Stationary Source Control Measure Analysis at C-94, *available at:* http://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/C.pdf [hereinafter referred to as "SJVAPCD 2018 $PM_{2.5}$ Attainment Plan"].

[562] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan pp. C-80–C-82. Note, the cost estimates assume that the existing foundation and supports will not be replaced and that direct and indirect annual costs are presumed to be the same as the existing burner.

[563] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan at C-81.

[564] *See, e.g.,* SCAQMD Presentation for Rule 1109.1 – NO_x Emission Reduction for Refinery Equipment, Working Group Meeting #9, December 12, 2019, slides 41 and 57, *available at:* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm_9_final.pdf?sfvrsn=12.

emission rate for small boilers <100 MMBtu/hr of 100 lb/MMscf (0.098 lb/MMBtu). Meeting an emission limit of 6 ppm from this uncontrolled level reflects a control efficiency using state-of-the-art ultra-low NOx burner technology of 93%. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

Table 36. Cost Effectiveness of Retrofitting Existing Units with ULNB to Achieve a NOx Level of 6 ppm at Boilers and Heaters >20 MMBtu/hr Operating at a 50% and 90% Capacity Factor.[565]

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2018$)	TOTAL ANNUALIZED COSTS (2018$)	COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR	COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR
30	$261,813	$19,518	$3,270	$1,817
40			$2,452	$1,362
50			$1,962	$1,090
60			$1,635	$908
70			$1,401	$779
80			$1,226	$681
90			$1,090	$606
100			$981	$545

Based on this analysis of SJVAPCD cost data, it can be cost effective to apply ULNB to existing units >20 MMBtu/hr to reduce NOx emissions to a level of 6 ppm.

SJVAPCD provides separate cost data for oilfield steam generators, noting that most of these units would be 62.5 MMBtu/hr.[566] The SJVAPCD analysis notes that, "[a]s many steam generators are one off built units, they may have different firebox configurations that may not accept the new burner without varying degrees of modification."[567] However, SJVAPCD analyzed retrofitting these units with new burner technology to achieve a NOx level as low as 5 ppm, based on vendor data. Using this same vendor cost data, the cost effectiveness of retrofitting a 62.5 MMBtu/hr unit to reduce NOx levels to 5 ppm ranges from $1,664/ton to $6,656/ton, depending on the extent of the modifications or upgrades that are needed.[568]

[565] Cost data provided by vendors to SJVAPCD, annualized costs calculated assuming a 25-year life and a 5.5% interest rate.

[566] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan at C-83.

[567] *Id.*

[568] This range of cost effectiveness is based on retrofit cost data of $450,000–$1,800,000 and assumes an 80% capacity factor from SJVAPCD's analysis. Annualized costs are calculated assuming a 25-year life and a 5.5% interest rate.

b) Units >5 and ≤20 MMBtu/hr

We also completed a cost effectiveness analysis of retrofitting existing units >5 and ≤20 MMBtu/hr with ULNB based on SJVAPCD vendor cost data for units of this size.[569] Table 37 presents the cost effectiveness of retrofitting existing units >5 and ≤20 MMBtu/hr with ULNB to reduce NOx emissions to 6 ppm from uncontrolled levels based on the EPA AP-42 uncontrolled emission rate for small boilers <100 MMBtu/hr of 100 lb/MMscf (0.098 lb/MMBtu). Meeting an emission limit of 6 ppm from this uncontrolled level reflects a control efficiency using state-of-the-art ultra-low NOx burner technology of 93%. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

Table 37. Cost Effectiveness of Retrofitting Existing Units with ULNB to Achieve a NOx Level of 6 ppm at Boilers and Heaters >5 and ≤20 MMBtu/hr Operating at a 50% and 90% Capacity Factor.[570]

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2018$)	TOTAL ANNUALIZED COSTS (2018$)	COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR	COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR
5	$69,816	$5,205	$5,232	$2,906
10			$2,616	$1,453
15			$1,744	$969
20			$1,308	$727

Based on this analysis using SJVAPCD cost data, it can be cost effective to apply ULNB to existing units >5 and ≤20 MMBtu/hr to reduce NOx emissions to a level of 6 ppm.

c) Units ≤5 MMBtu/hr

SMAQMD, in a cost effectiveness analysis for its most recent revision of its rules (in 2005) for boilers and heaters ≥1 MMBtu/hr, noted that, for units ≥1 MMBtu/hr and <5 MMBtu/hr, "[s]ome of these units may not be retrofitted because of equipment age and design and will have to be replaced with new units."[571]

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[569] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan pp. C-81–C-82. Note, the cost estimates assume that the existing foundation and supports will not be replaced and that direct and indirect annual costs are presumed to be the same as the existing burner.

[570] Cost data provided by vendors to SJVAPCD, annualized costs calculated assuming a 25-year life and a 5.5% interest rate.

[571] Sacramento Metropolitan AQMD Staff Report Rules 411 and 301, October 27, 2005, p. 10, *available at:* http://www.airquality.org/ProgramCoordination/Documents/Rules411and301%20StaffReport%20102705%20Item11.pdf [hereinafter referred to as "SMAQMD 2005 Rule 411 Staff Report"].

The SMAQMD cost data included the costs for replacing existing units with new units equipped with "low NOx technologies" in order to meet the District's emission limits, including costs for equipment, installation, permitting, and source testing for unit sizes ranging from 1–100 MMBtu/hr.[572] Operating and maintenance costs of a new low-NOx unit are assumed to be the same as older units. Thus, it is assumed that it is more cost effective to replace units that are of a size less than or equal to 5 MMBtu/hr with new units equipped with state-of-the-art combustion controls for NOx.

Table 38 below summarizes cost data for replacing units ≤5 MMBtu/hr with new units with "low NOx technologies." The costs include costs for equipment, installation, permitting, and source testing, along with calculated annualized costs of the control, and assume a 5.5% interest rate and a 30-year life of the new unit.[573] These low NOx technologies should last the life of the emission unit, and Colorado assumed a 30–40 year life for heater-treater units of this size based on manufacturer data.[574] We used a 30-year life as a minimum useful life for replacement heater or boiler controls in the cost effectiveness analysis, which is justified.

Table 38. Total and Annualized Costs of Replacement of Boilers and Heaters ≤5 MMBtu/hr with New Units with Low NOx Technologies.[575]

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2005$)	TOTAL ANNUALIZED COSTS (2005$)
1	$36,284	$2,551
2	$52,284	$3,652
3	$72,284	$5,028
4	$80,284	$5,579
5	$135,567	$9,328

For the units of 5 MMBtu/hr and lower, SMAQMD's Rule 411 establishes a NOx limit of 30 ppm, but there have been improvements in low NOx technologies demonstrating that units in this size range can meet NOx limits of 20 ppm and even as low as 9 ppm for some applications, based on a review of vendor information.[576] Several California Air Districts require units >2 and <5 to meet a limit of 7–12 MMBtu/hr and units ≤2 MMBtu/hr to meet a limit of 20 ppm. For example, SCAQMD Rule 1146.1 requires units >2 and <5 MMBtu/hr meet limits between 7–12 ppm, depending on the type of unit. And SJVAPCD Rule 4307 requires units >2 and ≤5 MMBtu/hr meet limits of 9 ppm (non-atmospheric units) and 12 ppm

[572] SMAQMD 2005 Rule 411 Staff Report Attachment D-1.
[573] SMAQMD 2005 Rule 411 Staff Report Attachment D-2.
[574] CDPHE RP for Heater-Treaters at 5.
[575] Cost data provided by boiler manufacturers to SMAQMD, annualized costs calculated assuming a 30-year life and a 5.5% interest rate.
[576] *See, e.g.,* Parker Industrial Boiler, offering units <5 MMBtu/hr with Low NOx Power Burners for NOx levels to 9 ppm. *Available at*: https://www.parkerboiler.com/products/.

(atmospheric units). SCAQMD Rule 1146.2 requires units ≤2 MMBtu/hr be manufactured to meet a NOx limit of 20 ppm and SCAQMD provides a list of numerous units that are pre-certified to meet this limit.[577] SJVAPCD also requires point-of-sale NOx limits for units ≤2 MMBtu/hr of 20 ppm.[578] And VCAPCD's Rule 74.15.1 currently requires new and replacement units ≥1 and ≤2 MMBtu/hr to also meet a 20 ppm NOx limit.[579] See Table 42 for a complete and more detailed list of state and local rules, including many with limits for units in this size range of 9–20 ppm.

While the costs of NOx combustion control technologies to meet NOx limits as low as 9 ppm may be higher than what SMAQMD assumed in its 2005 cost analysis, it is also likely that the costs of low NOx combustion controls have not changed much since then. This is because as air pollution controls are required to be implemented more frequently over time, the cost of the air pollution control often decreases due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. For example, SCAQMD concluded from its 2008 cost analysis that, "[t]he capital cost for retrofitting a unit has decreased by about 70%...."[580]

Therefore, we calculated the cost effectiveness of retrofitting these size units with low NOx technologies using these cost data based on two emission control scenarios: (1) meeting the SMAQMD limit of 30 ppm; and (2) meeting limits achievable today with low NOx combustion technology.

Table 39 below summarizes the cost effectiveness of replacing existing units ≤5 MMBtu/hr with new units with low NOx technologies, based on SMAQMD cost data shown above in Table 38. Table 39 below presents the cost effectiveness of replacement units with low NOx technologies to reduce NOx emissions from the uncontrolled emission rate based on EPA for units >2 MMBtu/hr and the SCAQMD-derived average unit emission rate of 110 ppmv (0.136 lb/MMBtu/hr) for units ≤2 MMBtu/hr. The SCAQMD-average unit emission rate was, "derived by the SCAQMD to calculate the baseline emissions for this [size] category."[581] This rate, "accounts for units that are considerably older and also for ones that have not had continual maintenance and upkeep."[582] Operating and maintenance costs of a new low-NOx unit are assumed to be the same as older units. For the second scenario, the analysis assumes units >2 and ≤5 MMBtu/hr meet a NOx limit of 9 ppm and units ≤2 MMBtu/hr meet a NOx limit of 20 ppm. Meeting emission limits of 9 ppm and 20 ppm from the estimated uncontrolled levels reflect a control efficiency of 89% and 82%, respectively. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

[577] *See* http://www.riteboiler.com/docs/Rite-Low-NOx-SCAQMD-Precertified-Boilers.pdf.
[578] SJVAPCD Rule 4308. *Available at:* https://www.valleyair.org/rules/currntrules/03-4308_CleanRule.pdf.
[579] VCAPCD Rule 74.15.1. *Available at:* http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.15.1.pdf.
[580] SCAQMD 2018 Draft Staff Report at 4-3. Note, while SCAQMD's analysis specifically applies to retrofitting units ≥20 and <75 MMBtu/hr with ULNB it's also possible that these changes in cost would apply to units of other sizes, as well.
[581] SJVAPCD 2009 Final Draft Staff Report for Rule 4308.
[582] *Id.*

Table 39. Cost Effectiveness of Replacing Existing Boilers and Heaters ≤5 MMBtu/hr with New Units with Low NOx Technologies Operating at a 50% and 90% Capacity Factor.[583]

UNIT SIZE (MMBtu/hr)	COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR NOx RATE: 30 ppm	COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR NOx RATE: 30 ppm	COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR NOx RATES: 20 ppm (≤2 MMBtu/hr) 9 ppm (>2 MMBtu/hr)	COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR NOx RATES: 20 ppm (≤2 MMBtu/hr) 9 ppm (>2 MMBtu/hr)
1	$12,160	$6,756	$10,809	$6,005
2	$8,703	$4,835	$7,736	$4,298
3	$12,322	$6,846	$8,771	$4,873
4	$10,254	$5,696	$7,298	$4,055
5	$13,715	$7,619	$9,762	$5,423

For the smallest units, San Joaquin Valley APCD (SJVAPCD) analyzed the cost of reducing NOx emissions for its point-of-sale rule for boilers and process heaters sized 0.075 to less than 2 MMBtu/hr. Table 40 below shows the differential capital costs (i.e., the difference in cost between a compliant and non-compliant unit), the annualized costs re-calculated using on a 5.5% interest rate (in place of the 10% interest rate assumed by SJVAPCD), and the cost of NOx reduction based on a current unit average emission rate of 110 ppmv meeting a limit of 20 ppmv. For units ≤2 MMBtu/hr uncontrolled emissions are estimated based on the SCAQMD-derived average unit emission rate of 110 ppmv (0.136 lb/MMBtu/hr). Operating and maintenance costs of a new low-NOx unit are assumed to be the same as older units. Cost data were provided to SJVAPCD by stakeholders, retailers, and manufacturers. And again, we used a 30-year life as a minimum life for replacing unit controls with low NOx technologies in the cost effectiveness analysis, as previously discussed. SJVAPCD used a 22% capacity factor in its analysis based on survey data collected by SCAQMD and Bay Area AQMD for "typical usages for these units," which presumably reflect a wide range of application and do not necessarily reflect how these size units are used in oil and gas applications, where heaters can operate continuously.

[583] Cost data provided by boiler manufacturers to SMAQMD (2005$), annualized costs calculated assuming a 30-year life and a 5.5% interest rate.

Table 40. Cost Effectiveness Based on Differential Costs to Reduce NOx Emissions from Replacing Units with Units with Low-NOx Burner Technology to Meet a NOx Limit of 20 ppm, Operating at 22% Capacity[584]

UNIT SIZE (MMBtu/hr)	DIFFERENTIAL CAPITAL COST (2009$)	ANNUALIZED COST (2009$)	COST EFFECTIVENESS (2009$)
0.75	$100	$8	$883/ton
0.4	$750	$63	$1,242/ton
2.0	$3,000	$251	$994/ton

For units operating at a higher capacity factor, as would likely be the case for many of the units used in the oil and gas production and processing segments, the cost per ton of NOx removal of choosing to replace a unit with a new unit with low NOx technologies over a higher-emitting unit would be even less than what is shown in Table 40. For these type of smaller units, SCAQMD Rule 1146.2 requires units with rated capacities between 400,000 and 2,000,000 Btu/hr (i.e., 0.04 and 2 MMBtu/hr) and more than 15 years old, depending on the original manufacturer date, to meet the same emission standards as new units.[585] Meeting these standards, according to SCAQMD, requires the retrofit, or more likely, replacement of the older units.[586]

In its initial regional haze plan, Colorado completed a Reasonable Progress Evaluation for the heater-treater source category, including a NOx emission 4-Factor analysis for reasonable progress toward the national visibility goal.[587] In its evaluation, Colorado reported that:

> The Four Corners Air Quality Task Force considered low NOx burners as a mitigation option for the Four Corners area and had the following finding: "Application not appropriate for the San Juan Basin, because most burners commonly used in the Four Corners Area are smaller than the technology is capable of providing emission reduction." It appears likely that this technology would also be technically infeasible for the Denver-Julesburg (DJ) Basin considering that low-NO_X burners are not commercially available for very small combustion sources such as heater-treaters.[588]

[584] *See* SJVAPCD 2009 Final Draft Staff Report for Rule 4308. Annualized costs of control were calculated using a capital recovery factor of 0.068805 (assuming a 30-year life of controls and a 5.5% interest rate). NOx emission reductions are based on SJAPCD's assumed unit average emission rate of 110 ppmv meeting an emission limit of 20 ppmv.

[585] SCAQMD Rule 1146.2, *available at:* http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1146-2.pdf?sfvrsn=17.

[586] *See* SMAQMD 2010 Rule 414 Staff Report at 13 (describing SCAQMD rules).

[587] CDPHE RP for Heater-Treaters.

[588] *Id.* at 3.

The Four Corners Air Quality Task Force report was from 2007 and there have been great improvements since then in low NOx technologies. As shown throughout this section on combustion modifications, however, units around 2 MMBtu/hr, and even smaller, are available with low NOx technologies that can meet very low NOx emission limits and can even, in some cases, be retrofitted with these technologies to achieve emissions reductions from existing units. Note, Colorado's RP for Heater-Treaters indicates that a typical heater-treater design rate is about half of the 5 MMBtu/hr threshold for exemptions from Colorado's permitting requirements.[589] And beyond these very small units, low NOx technologies are widely available and generally cost effective for units ≥5 MMBtu/hr.

2. LOWERING COMBUSTION TEMPERATURES TO REDUCE NOx EMISSIONS

Colorado also considered lowering heater-treater temperatures to reduce NOx emissions and described this combustion modification approach, as follows:

> This technology (lowering the heater-treater temperature) was identified by EPA Natural GasSTAR in PRO Fact Sheet No. 906. The fact sheet was written with reduction of methane in mind, although this technology would also reduce combustion emissions because it would reduce fuel use. The following is from the fact sheet: "...heater-treater temperatures at remote sites may be higher than necessary, resulting in increased methane emissions. Commonly, the reason for this is that operators need to reduce the chance of having a high water content in the produced oil and manpower limitations do not allow for constant monitoring at remote sites. Field personnel, consequently, are inclined to operate the equipment at levels that cause the least problems, but also result in higher than necessary emissions."[590]

Estimates for NOx emission reductions from lowering heater-treater temperatures were not provided in EPA's Gas STAR analysis and were not assessed by Colorado. Capital costs were estimated at $1,000–$10,000 and annual operating and maintenance costs were estimated to range from $100–$1,000.[591] Colorado anticipated that there would be no additional time needed for achieving compliance with this technology, that the lowered heater-treater temperature would reduce fuel use, and that there would be no non-air quality impacts. Further, Colorado concluded that this control technology would not affect the service life of the heater-treater, noting that the typical life of a heater-treater is 30 to 40 years.[592]

There are few energy and non-air environmental impacts of combustion modifications for heaters and boilers. Generally, the combustion practices used to reduce NOx emissions also increase thermal efficiencies by reducing the amount of excess air needed for combustion, which has the added benefit

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[589] *Id.* at 5.
[590] *Id.* at 2.
[591] *See* EPA Partner Reported Opportunities (PRO) Fact Sheet No. 906 (last updated September 2004), *available at:* https://www.globalmethane.org/documents/m2mtool/docs/lowerheatertreatertemp.pdf and CDPHE RP for Heater-Treaters at 3.
[592] CDPHE RP for Heater-Treaters at 4.

of reducing fuel usage and increasing energy savings. According to EPA, "[r]eductions in NOx formation achieved by reducing flame temperature and oxygen levels can increase CO and HC emissions if NOx reductions by combustion controls are taken to extremes."[593] And systems where blowers or fans are used, e.g., for LNB plus FGR, will require additional electric energy.

According to EPA, the length of time to install ULNB is 6–8 months (excluding permitting, reporting preparation, and programmatic and administrative considerations).[594]

While the cost estimates in this section on combustion modification are of a cost basis that spans a timeframe from 1986–2018, it is important to note that, beginning in 2006, several state and local air agencies adopted rules to lower NOx emission limits of 30 ppmv to as low as 5–12 ppm for larger units and found it was cost effective to require such a level of control on existing boilers and heating units. This will be discussed further in Section F. below. It is not possible to accurately escalate the older costs to more current dollars. EPA cautions against escalating costs over a period longer than five years because it can lead to inaccuracies in price estimation.[595] Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. In some cases, the cost of the air pollution control decreases over time due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc.[596] In any event, the fact that air agencies have found low NOx combustion technologies to be cost effective to meet NOx emission limits in the range of 5 to 30 ppm indicates that similar sources have had to incur the costs reflected in Tables 36-40 to meet reduced NOx emission limits, and thus the costs of low NOx combustion technology should be considered reasonable for most heaters and boilers.

B. POST-COMBUSTION CONTROLS: SCR AND SNCR

Post-combustion controls, such as SCR and SNCR, reduce NOx formation in the flue gas. The following is EPA's description of these add-on control techniques:

> These techniques control NOx by using a reactant that reduces NOx to nitrogen (N2) and water. The reactant, ammonia (NH3) or urea for SNCR, and NH3 for SCR, is injected into the flue gas stream. Temperature and residence time are the primary factors that influence the reduction reaction. Selective catalytic reduction uses a catalyst to facilitate the reaction.[597]

[593] EPA 1993 ACT for Process Heaters Section 2.4.
[594] 2016 EPA CSAPR TSD for Non-EGU Emissions Controls at 15.
[595] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.
[596] For example, SCAQMD concluded from its 2008 cost analysis that, "[t]he capital cost for retrofitting a unit has decreased by about 70%...." (SCAQMD 2018 Draft Staff Report at 4-3).
[597] EPA 1993 ACT for Process Heaters at 2-6.

SCR systems on natural gas-fired boilers and heaters should be able to achieve NOx removal efficiencies in the range of 80 to 90+%.[598] SNCR systems on natural gas-fired industrial boilers and heaters can achieve NOx reductions in the range of 30-75%.[599]

As early as 1991, CARB, in its 1991 RACT / BARCT determination for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, identified SCR and SNCR as two of four control methods (along with FGR and LNB).[600] CARB concluded that, for units ≥5 MMBtu/hr (and ≥90,000 therms annual heat input), a BARCT NOx limit of 30 ppmv (0.036 lbs/MMBtu) could be achieved by installing new burners with FGR, noting that some units would "need to install selective noncatalytic reduction or other emission control technology instead of flue gas recirculation due to particular unit design problems."[601]

EPA provided cost effectiveness data for SNCR at model heaters in its 1993 Alternative Control Techniques document. Specifically, cost effectiveness of SNCR for heaters, at the time, ranged from: (1) $3,200–$6,700/ton for a 77 MMBtu/hr heater; (2) $2,700–$5,700/ton for a 121 MMBtu/hr heater; and (3) $2,300–$4,900/ton for 186 MMBtu/hr heater.[602]

California Air Districts have long been regulating NOx emissions from boilers and process heaters, with CARB issuing RACT / BARCT guidance to Air Districts in 1991.[603] In its 1991 guidance, CARB determined the cost effectiveness of SNCR (in 1986$) for units as small as 50 MMBtu/hr and as large as 375 MMBtu/hr, as follows: (1) $1,500–$6,000/ton for units operating at a 50% capacity factor; and (2) $1,300–$3,800/ton for units operating at a 90% capacity factor.[604]

More recent and more detailed cost data are available from California Air Districts that have adopted, and continue to update, regulations for these sources. A recent analysis by California's SCAQMD for revisions to its series of rules for boilers and process heaters (i.e., Rules 1146, 1146.1, and 1146.2) concluded that, "[u]pon reviewing the type of pollution control technologies available to control NOx emissions applicable to the boilers, steam generators and process heaters subject to Rule 1146 and 1146.1, SCR and ultra-low NOx burners are still the main technologies that can achieve the NOx concentration limits specified in these rules."[605] SCAQMD further determined that, "[b]ased on the 2008 staff reports for Rule 1146 and 1146.1, SCR as applied to Rule 1146 boilers can achieve NOx

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[598] *See* Petroleum Refinery Tier 2 BACT Analysis Report, Prepared for EPA by Eastern Research Group, Inc., January 16, 2001, at 3-11, available at: https://archive.epa.gov/airquality/ttnnsr01/web/pdf/bactrpt.pdf. *See* also NESCAUM 2000 Status Report at II-7. These are both cited by EPA in its Chapter 2, Selective Catalytic Reduction, June 2019, in Section 4 of EPA's Control Cost Manual (References 19 and 24)

[599] *See* EPA, Control Cost Manual, Section 4, Chapter 1, Selective Noncatalytic Reduction, at 1-2, *available at:* https://www.epa.gov/sites/production/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf.

[600] CARB 1991 Guidance at 8.

[601] CARB 1991 Guidance at 6.

[602] EPA 1993 ACT for Process Heaters Table 2-4. EPA calculates an annualized cost of control assuming a capital recovery factor of 0.131474 (i.e., assuming a 15-year life of controls and a 10% interest rate).

[603] CARB 1991 Guidance.

[604] CARB 1991 Guidance Table 4. Note, CARB does not identify the underlying assumptions for annualized costs, life of controls, etc.

[605] SCAQMD 2018 Draft Staff Report at 2-4.

concentrations from 5 to 6 ppm for units greater than or equal to 75 MMBtu/hr."[606] SCAQMD's revisions to Rule 1146 for Boilers, steam generators, and process heaters ≥5 MMBtu/hr allow facilities until January 1, 2022 to retrofit all existing units and until January 1, 2023 to replace any existing units to meet a NOx emission limit of 5 ppm for units ≥75 MMBtu/hr burning natural gas.[607] SCAQMD determined that the 1146 rule series are cost effective, including for units ≥75 MMBtu/hr retrofitted with SCR to meet an emission limit of 5 ppm.[608]

In the SJVAPCD, the District described the following approach to achieving lower NOx limits, acknowledging certain technical and cost feasibility considerations with SCR for certain units:

> The amendment of Rule 4306 in October 2008 was initially proposed to lower the NOx emission limit from 9 ppmv to 6 ppmv for units greater than 20 MMBtu/hr. It was determined that the proposed NOx limits could be accomplished by using selective catalytic reduction (SCR) or a combination of SCR and ultra-low NOx burners (ULNBs), thus making the lower limits technologically feasible. However, through the public workshop process and additional research it was also determined that most of the units subject to Rule 4306 have undergone several generations of NOx controls, and consequently, certain applications of SCR may not be cost effective and/or technological infeasible because of physical limitations. Therefore, the lower NOx limits were included in new Rule 4320 and an option was provided in the rule that allows for the payment of an annual emissions fee based on total actual emissions, rather than installation of additional NOx controls. These fees are used by the District to achieve cost effective NOx reductions through District incentive programs, the District's Technology Advancement Program, and other routes.[609]

SJVAPCD is in the process of reviewing its rules for boilers and process heaters >5 MMBtu/hr and is proposing updates as part of its 2018 $PM_{2.5}$ Attainment Plan commitments to reduce NOx emissions.[610] SJVAPCD is considering lowering NOx limits for units >5 MMBtu/hr to levels ranging from 2–3.5 ppm.[611] As part of its control measure analysis, SJVAPCD analyzed the cost effectiveness of retrofitting units of varying sizes with SCR to achieve these NOx levels, based on information from SCR vendors. We assume these data are in 2018$.

The SJVAPCD cost data for retrofitting existing units with SCR includes detailed direct and indirect capital, installation, and operating and maintenance costs for two unit size categories: (1) units >5 and ≤20 MMBtu/hr; and (2) units >20 MMBtu/hr.[612]

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[606] *Id.* at 2-2.
[607] *Id.* at 1-2.
[608] *Id.* at 4-6.
[609] *See* SJVAPCD 2016 Plan for the 2008 8-Hour Ozone Standard (June 16, 2016), p. C-27, *available at:* http://www.valleyair.org/Air_Quality_Plans/Ozone-Plan-2016/c.pdf.
[610] SJVAPCD Rules 4306 and 4320. *See*: https://www.valleyair.org/Workshops/public_workshops_idx.htm#12-05-19_ICE.
[611] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan pp. C-84–C-87.
[612] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan pp. C-80–C-82. Note, the cost estimates assume that the existing foundation and supports will not be replaced and that direct and indirect annual costs are presumed to be the same as the existing burner.

Table 41 below summarizes the total costs for retrofitting existing units ≥5 MMBtu/hr with SCR, based on SJCAPCD-obtained vendor data, along with calculated annualized costs of the control, assuming a 5.5% interest rate and a 25-year life for SCR. SCAQMD is currently assuming a 25-year life for refinery heaters and boilers.[613] Table 41 also presents the cost effectiveness of applying SCR existing units to reduce NOx emissions from uncontrolled levels to levels of: (1) 2.5 ppm for units >20 MMBtu/hr; and (2) 3.5 ppm for units >5 and ≤20 MMBtu/hr.[614] Uncontrolled emissions are based on the EPA AP-42 uncontrolled emission rate for small boilers <100 MMBtu/hr of 100 lb/MMscf (0.098 lb/MMBtu). Meeting emission limits of 2.5 ppm and 3.5 ppm from this uncontrolled level reflects a control efficiency using state-of-the-art SCR technology of 96% and 97%, respectively. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

Table 41. Cost Effectiveness of Retrofitting Existing Units with SCR to Achieve NOx Levels of 2.5 ppm for Units >20 MMBtu/hr and 3.5 ppm for Units >5 and ≤20 MMBtu/hr Operating at a 50% and 90% Capacity Factor.[615]

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2018$)	TOTAL ANNUALIZED COSTS (2018$)	COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR	COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR
5	$261,728	$26,055	$25,354	$14,086
10			$12,677	$7,043
15			$8,451	$4,695
20			$6,339	$3,521
30	$385,705	$38,397	$6,149	$3,416
40			$4,612	$2,562
50			$3,689	$2,050
60			$3,074	$1,708
70			$2,635	$1,464
80			$2,306	$1,281
90			$2,050	$1,139
100			$1,845	$1,025

[613] *See, e.g.,* SCAQMD Presentation for Rule 1109.1 – NO_x Emission Reduction for Refinery Equipment, Working Group Meeting #9, December 12, 2019, slides 41 and 57, *available at:* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm_9_final.pdf?sfvrsn=12.

[614] *See* SJVAPCD 2018 $PM_{2.5}$ Attainment Plan at C-85 and C-87, stating: "Source test results of various units with SCR systems indicate that an SCR can potentially achieve 3.5 ppmv NOx @ 3% O2 for units rated between 5 to 20 MMBtu/hr." and "Source test results of various units with SCR system indicate that an SCR can reliably achieve 2.5 ppmv NOx @ 3% O2 (or less) emissions for units greater than 20 MMBtu/hr."

[615] Cost data provided by vendors to SJVAPCD, annualized costs calculated assuming a 25-year life and a 5.5% interest rate.

SJVAPCD based its cost analysis on vendor data for the SCR systems and largely on EPA's Air Pollution Control Cost Manual (6th Edition) for installation, operating and maintenance costs, etc., for these systems.

This analysis indicates that it is cost effective to retrofit units, especially those >20 MMBtu/hr, with SCR to achieve NOx levels as low as 2.5–3.5 ppm.

The energy and non-air environmental impacts of post-combustion control techniques include:

- Parasitic load of operating an SCR system, which requires additional energy (fuel use and electricity) in order to maintain output across the catalyst;
- Solid waste disposal of spent SCR catalyst;
- Ammonia, CO, and nitrous oxide emissions with the use of SNCR;
- Ammonia and sulfite emissions with the use of SCR; and
- Ammonia handling and storage with SNCR and SCR.[616]

According to EPA, the length of time to install SCR is 28–58 weeks (excluding permitting, reporting preparation, and programmatic and administrative considerations).[617] The Institute of Clean Air Companies has stated that SCRs for smaller units (less than 20,000 standard cubic feet per minute gas throughput) are often available in ready-to-install SCR skid packages, and thus SCR for smaller units would take closer to 28 weeks to install.[618] An SNCR would take much less time to install. The Institute of Clean Air Companies states that it takes about 10-13 months to install SNCR, which covers the time from bid evaluations to startup of the SNCR.[619]

C. NOx CONTROLS FOR SEPARATORS

Colorado's Reasonable Progress Evaluation for the heater-treater source category evaluated the installation of insulation on the separator to reduce fuel usage, and resulting combustion emissions (including NOx).[620] Installation of insulation on separators was also included in the Four Corners Air Quality Task Force Report of Mitigation Options for the oil and gas industry and determined to be a technically feasible technique for reducing NOx emissions.[621] Estimates for NOx emission reductions from insulating separators were not provided in the Four Corners Air Quality Task Force report and were not assessed by Colorado. The cost effectiveness of this control will depend on the remaining life of the

[616] EPA 1993 ACT for Process Heaters Section 2.4.
[617] 2016 EPA CSAPR TSD for Non-EGU Emissions Controls at 15.
[618] *See* Institute of Clean Air Companies, Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources, December 4, 2006, at 4-5, *available at:* https://cdn.ymaws.com/icac.site-ym.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.
[619] *Id.* at 7-8.
[620] CDPHE RP for Heater-Treaters.
[621] Four Corners Air Quality Task Force Report of Mitigation Options (November 1, 2007) at 89.

equipment to which it is applied. Colorado anticipated that there would be no additional time needed for achieving compliance with this technology and that there would be no non-air quality impacts.

D. NOx CONTROLS FOR DEHYDRATORS

Use of a zero emission dehydrator can significantly reduce fuel requirements for a reboiler and therefore reduce combustion emissions (including NOx). The Four Corners Air Quality Task Force report identified this type of dehydrator as a mitigation option and described this type of unit and its emissions, as follows:

> The zero emissions dehydrator combines several technologies that lower emissions. These technologies eliminate emissions from glycol circulation pumps, gas strippers and the majority of the still column effluent. . . . Benefits of this technology include: . . . Reduces emissions of particulate matter, sulfur dioxide, NOx or CO emissions . . . Significantly reduces fuel requirements for glycol reboiler. Natural gas that was used for this purpose can now be sent to market.[622]

The Four Corners Air Quality Task Force report describes how existing dehydrators can be retrofitted to zero emissions dehydrators, "by modifying the gas stream piping and using a 5 kW engine-generator for electricity needs."[623] The Four Corners Air Quality Task Force reports that operating and maintenance costs are lower than for conventional glycol dehydrators and further reports that EPA estimates the payback for installing a zero emission dehydrator in place of a conventional glycol dehydrator to occur in less than a year.[624]

E. CENTRAL GATHERING FACILITIES TO REDUCE NOx EMISSIONS FROM WELLHEAD SEPARATION SOURCES

Centralization of gas well gathering facilities can be employed to reduce and consolidate wellsite sources, including heaters and separators. Colorado's Reasonable Progress Evaluation for the heater-treater source category evaluated central gathering facilities to remove wellhead separation.[625] With centralization, emissions from heater-treaters would be reduced because fewer heater-treaters would be needed. Colorado described the effectiveness of this restructuring, as follows:

> Removing individual heater-treaters and replacing them with a central gathering facility would eliminate emissions from the heater-treaters. The central gathering facility would be a new source of emissions; however, overall emissions will be reduced. Not only would combustion emissions from the multiple heater-treaters be eliminated, VOC emissions from condensate

[622] *Id.* at 92.
[623] *Id.* at 93. The report further notes that the electricity needs require a "fuel or power source, for which associated emissions need to be quantified."
[624] *Id.* at 93.
[625] CDPHE RP for Heater-Treaters.

> tanks (which would also be removed from wellheads if this technology was implemented) would be eliminated. If a vapor recovery unit (VRU) were used at the central gathering facility, VOCs could be compressed back into the gas stream.[626]

Colorado acknowledges that it would be most cost effective to implement a centralized gathering facility on a new field but indicates that retrofitting a field already set up with infrastructure for wellhead separation would be site-specific and depends on several considerations, including the number of heater-treaters being removed, topography, gas composition, mineral rights, etc. Additional benefits of a centralized gathering facility include reduced truck traffic to wellheads (which can be significant sources of fugitive PM emissions) and a reduction in condensate and water tanks (and their associated fugitive emissions). States should consider requiring or otherwise advocating for centralized gathering facilities for new oil and gas development as a measure to prevent future visibility impairment.

Estimates for NOx emission reductions from the centralization of gas well gathering facilities were not assessed by Colorado other than saying that overall emissions will be reduced. Colorado anticipated that additional time needed for achieving centralization would be site-specific, e.g., depending on gas well density and topographical barriers. Finally, Colorado notes that central gathering facilities would be more efficient to operate, reducing overall energy impacts.

F. NOx EMISSION LIMITS THAT HAVE BEEN REQUIRED FOR HEATERS AND BOILERS

States and local air agencies have adopted NOx limits for existing boilers and heaters, many of which have been in place for more than 20 years and many of which have been strengthened over the years. In Table 42 below, we summarize some of those state and local air pollution requirements. Primarily, a review of California Air District rules was done for this report, because several of those air districts have adopted the most stringent NOx emission limitations.

Table 42 is a summary of the NOx emission limits required of existing boilers and heaters in states and local air districts across the United States. It is important to note that these are limits that, unless otherwise noted, currently apply to existing units and generally required an air pollution control retrofit. These NOx limits were most likely adopted to address nonattainment issues with the ozone and $PM_{2.5}$ NAAQS. Regardless of the reason for adopting the NOx emission limits, what becomes clear in this analysis is that governments have adopted NOx limitations that require low NOx technologies at boilers and heaters as small as 0.4 MMBtu/hr and SCR for units ≥75 MMBtu/hr. The lowest, most broadly applicable NOx limits are those recently adopted by SCAQMD and SJVAPCD. SJVAPCD has a more stringent limit than SCAQMD rules for units between 20 and 75 MMBtu/hr (7 ppm in SJVUAPCD Rule 4320 vs. 9 ppm in SCAQMD Rule 1146), however, it is important to note that for SJVUAPCD's Rules 4306 and 4320, the owner or operator has the option of paying into an annual emissions fee in lieu of

[626] *Id.* at 3.

complying with these limits. For units ≥ 75 MMBtu/hr, the emission limit in SCAQMD Rule 1146 of 5 ppm is more stringent than SJVAPCD's limit of 7 ppm.

Table 42. State/Local Air Agency Natural Gas-Fired Boiler and Heater Rules[627]

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
CA–SCAQMD	Rule 1146.[628] Adopted 9/9/98 Last revised 12/7/18	≥5 MMBtu/hr Effective 9/5/08	30 ppm (0.036 lb/MMBtu)
		≥5 MMBtu/hr Effective 1/1/14 Atmospheric units	12 ppm (0.015 lb/MMBtu)
		≥75 MMBtu/hr Effective 1/1/13 Excluding thermal fluid heaters	5 ppm (0.0062 lb/MMBtu)
		≥20 and <75 MMBtu/hr Effective 12/7/18 Excluding thermal fluid heaters, certain fire-tube boilers, and units with a previous NOx limit ≤12 and >5 ppm prior to 12/7/18	5 ppm (0.0062 lb/MMBtu)
		≥5 and <20 MMBtu/hr Effective 1/1/15 (or later for units with a previous NOx limit ≤12 ppm prior to 9/5/08) Excluding atmospheric units and thermal fluid heaters	9 ppm (0.011 lb/MMBtu)
		≥5 and <20 MMBtu/hr Effective 12/7/18 (or later for units with a previous NOx limit ≤9 ppm prior to 12/7/18) Fire-tube boilers excluding units with a previous NOx limit ≤12 and >9 ppm prior to 12/7/18	7 ppm (0.0085 lb/MMBtu)
		≥5 MMBtu/hr Effective 12/7/18 (or later for certain units at non-RECLAIM facilities) Thermal fluid heaters	12 ppm (0.015 lb/MMBtu)

[627] This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules applicable to the types of units found in the oil and gas industry, but the authors recommend that readers check each specific rule for the details of how the rule applies to different units, and in case of any errors in this table.
[628] https://ww3.arb.ca.gov/drdb/sc/curhtml/r1146.pdf.

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
CA–SCAQMD	Rule 1146.1[629] Adopted 10/5/90 Last revised 12/7/18	>2 and <5 MMBtu/hr Effective 9/5/08	30 ppm (0.036 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 1/1/14 Atmospheric units	12 ppm (0.015 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 1/1/14 (or later for units with a previous NOx limit ≤12 and >9 ppm prior to 9/5/08) Excluding atmospheric units, thermal fluid heaters, and certain fire-tube boilers	9 ppm (0.011 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 12/7/18 (or later for units with a previous NOx limit ≤9 ppm prior to 12/7/18) Fire-tube boilers excluding units with ≤12 and >9 ppm prior to 12/7/18	7 ppm (0.0085 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 12/7/18 (or later for certain units at non-RECLAIM facilities) Thermal fluid heaters	12 ppm (0.015 lb/MMBtu)
CA–SCAQMD	Rule 1146.2[630] Adopted 1/9/98 Last revised 12/7/18	>0.4 and ≤2 MMBtu/hr Effective 1/1/10 Units manufactured or offered for sale	20 ppm (0.024 lb/MMBtu)
		>1 and ≤2 MMBtu/hr Effective 1/1/06 Units more than 15 years old manufactured on or after 1/1/92, except for units at a RECLAIM or former RECLAIM facility	30 ppm (0.037 lb/MMBtu)
		>0.4 and ≤1 MMBtu/hr Effective 1/1/06 Units more than 15 years old manufactured prior to 1/1/00, except for units at a	30 ppm (0.037 lb/MMBtu)

[629] http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1146-1.pdf.
[630] http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1146-2.pdf?sfvrsn=17.

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
		RECLAIM or former RECLAIM facility	
CA–SJVAPCD	Rule 4320[631] Adopted 10/16/08	>5 and ≤20 MMBtu/hr Effective 1/1/14 Except for certain other units[632]	6 ppmv (0.007 lb/MMBtu)[633]
		>20 MMBtu/hr Effective 1/1/14[634] Except for refinery units,[635] and certain other units[636]	5 ppmv (0.0062 lb/MMBtu)[637]
		>5 MMBtu/hr Effective at the next unit replacement but no later than 1/1/14 Certain units[638]	9 ppmv (0.011 lb/MMBtu)
CA–SJVAPCD	Rule 4306 (Phase 3)[639]	>5 and ≤20 MMBtu/hr	9 ppmv (0.011 lb/MMBtu)

[631] https://www.valleyair.org/rules/currntrules/r4320.pdf.

[632] These certain other units include: (1) those installed prior to 1/1/09 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/yr but ≤30 billion Btu/yr; (2) units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas; and (3) units operated by a small producer in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 and 20 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

[633] Note, the owner or operator has the option of paying into an annual emissions fee based on total actual emissions, rather than installation of additional NOx controls. These fees are used by the District to achieve cost effective NOx reductions through incentives programs, etc.

[634] The rule allows for a "Staged Enhanced Schedule" for oil field steam generators and refinery units as follows: (1) Initial Limit of 9 ppmv (0.011 lb/MMBtu), effective 7/1/12; and (2) Final Limit of 5 ppmv (0.0062 lb/MMBtu), effective 1/1/14.

[635] Note, refinery unit requirements are the same except that these units have a Standard Schedule limit of 6 ppm, effective 7/1/11.

[636] These certain other units include: (1) those installed prior to 1/1/09 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/yr but ≤30 billion Btu/yr; (2) units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas; and (3) units operated by a small producer in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 and 20 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

[637] Note, the owner or operator has the option of paying into an annual emissions fee based on total actual emissions, rather than installation of additional NOx controls. These fees are used by the District to achieve cost effective NOx reductions through incentives programs, etc.

[638] These certain other units include: (1) those installed prior to 1/1/09 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/yr but ≤30 billion Btu/yr; (2) units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas; and (3) units operated by a small producer in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 and 20 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

[639] https://ww3.arb.ca.gov/drdb/sju/curhtml/r4306.pdf.

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
	Adopted 9/18/03 Last revised 10/16/08	Effective 12/1/08 Except for oil field steam generators, refinery units, and certain other units[640]	
		>20 MMBtu/hr Effective 1/1/14 Except for oil field steam generators, refinery units, and certain other units[641]	6 ppmv (0.007 lb/MMBtu)
		>5 MMBtu/hr Effective 6/1/07 Oilfield steam generators Load-following units[642]	15 ppm (0.036 lb/MMBtu)
		>5 MMBtu/hr Effective 6/1/07 Certain other units[643]	30 ppm (0.036 lb/MMBtu)
CA–SJVAPCD	Rule 4307[644] Adopted 12/15/05 Last revised 4/21/16	>2 and ≤5 MMBtu/hr Existing units	30 ppm (0.036 lb/MMBtu)
		>2 and ≤5 MMBtu/hr New or replacement units Effective 1/1/16 Atmospheric units Non-atmospheric units	 12 ppm (0.014 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA–SJVAPCD	Rule 4308[645] Adopted 10/20/05 Last revised 11/14/13	>0.4 and <2 MMBtu/hr Effective 1/1/15 Point-of-sale[646] PUC gas Non-PUC gas	 20 ppm (0.024 lb/MMBtu) 30 ppm (0.036 lb/MMBtu)
CA–SMAQMD	Rule 411[647]	Effective 10/27/09	

[640] These certain other units include: (1) load-following units; (2) units limited by a Permit to Operate to an annual heat input 9–30 billion Btu/yr; and (3) units in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is > 5 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

[641] *Id*.

[642] Load-following units must meet a limit of 9 ppm under the Enhanced Schedule, with a compliance date of 12/1/08.

[643] These certain other units include: (1) refinery units >5 and ≤65 MMBtu/hr (note that units >65 and ≤110 MMBtu/hr are required to meet a limit of 25 ppm (0.031 lb/MMBtu and units >110 MMBtu/hr are required to meet a limit of 5 ppm); (2) units limited by a Permit to Operate to an annual heat input 9–30 billion Btu/yr; and (3) units in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is > 5 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

[644] https://www.valleyair.org/rules/currntrules/Rule4307.pdf.

[645] https://www.valleyair.org/rules/currntrules/03-4308_CleanRule.pdf.

[646] This point-of-sale rule covers units supplied, sold, offered for sale, installed, or solicited for installation.

[647] http://www.airquality.org/ProgramCoordination/Documents/rule411.pdf.

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
	Adopted 2/2/95 Last revised 8/23/07	New and existing units ≥1 and <5 MMBtu/hr ≥5 and ≤20 MMBtu/hr >20 MMBtu/hr	 30 ppm (0.036 lb/MMBtu) 15 ppm (0.036 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA–SMAQMD	Rule 414[648] Adopted 8/1/96 Last revised 10/25/18	>0.4 and <1 MMBtu/hr Effective 10/25/18 (date of last revision) Point-of-sale[649]	20 ppm (0.024 lb/MMBtu)
CA–VCAPCD	Rule 74.15.1[650] Adopted 5/11/93 Last revised 6/23/15	≥1 and <5 MMBtu/hr Effective 1/1/16 Existing units New and Replacement: Atmospheric units Pressurized Units	 30 ppm (0.036 lb/MMBtu) 12 ppm (0.014 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA–Santa Barbara County APCD	Rule 361[651] Adopted 1/17/08 Last revised 6/20/19	>2 and <5 MMBtu/hr Existing units Installed and modified (after 1/1/20): Atmospheric units Non-atmospheric Units	 30 ppm (0.036 lb/MMBtu) 12 ppm (0.014 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA–Santa Barbara County APCD	Rule 342[652] Adopted 3/10/92 Last revised 6/20/19	≥5 MMBtu/hr Existing units Installed and modified (after 1/1/20): ≥5 and ≤20 MMBtu/hr >20 MMBtu/hr	 30 ppm (0.036 lb/MMBtu) 9 ppm (0.011 lb/MMBtu) 7 ppm (0.0085 lb/MMBtu)
CA–Feather River AQMD	Rule 3.23[653] Adopted 10/3/16	>0.4 and <1 MMBtu/hr Effective 1/1/17 Point-of-sale[654]	20 ppm (0.024 lb/MMBtu)
CA–Bay Area AQMD	Regulation 9 Rule 7[655] Adopted 9/16/92	>2 and ≤5 MMBtu/hr Effective 1/1/15	30 ppm (0.036 lb/MMBtu)

[648] http://www.airquality.org/ProgramCoordination/Documents/rule414.pdf.

[649] This point-of-sale rule covers units manufactured, distributed, offered for sale, sold, or installed.

[650] http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.15.1.pdf.

[651] https://www.ourair.org/wp-content/uploads/rule361.pdf.

[652] https://www.ourair.org/wp-content/uploads/rule342.pdf.

[653] https://ww3.arb.ca.gov/drdb/fr/curhtml/r3-23.pdf.

[654] This point-of-sale rule covers units offered for sale, sold, or installed.

[655] https://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-7-nitrogen-oxides-and-carbon-monoxide-from-industrial-institutional-and-commercial-boiler/documents/rg0907.pdf?la=en.

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
		>5 and <10 MMBtu/hr Effective 1/1/15 ≥10 and <20 MMBtu/hr Effective 1/1/14 ≥20 and <75 MMBtu/hr Effective 1/1/14 ≥75 MMBtu/hr Effective 1/1/14 Excluding thermal fluid heaters	15 ppm (0.036 lb/MMBtu) 15 ppm (0.036 lb/MMBtu) 9 ppm (0.011 lb/MMBtu) 5 ppm (0.0062 lb/MMBtu)
TX- Houston-Galveston-Brazoria Area	30 TAC 117.2010(c)(1) Emission Specs for 8hr ozone demo[656]	Emission specs for mass emission cap and trade	0.036 lb/MMBtu (or, alternatively 30 ppm @ 3% O2)
TX	30 TAC 117.3205(a) [657]	Statewide Point-of-sale[658] Effective 7/1/02 >0.4 and ≤2 MMBtu/hr	30 ppm or 0.037 lb/MMBtu
MA	310 CMR 7.26(30)[659]	≥10 and <40 MMBtu/hr Effective 9/14/01	0.0350 lb/MMBtu
NY	6 CRR-NY 227-2.4[660]	>25 and ≤100 MMBtu/hr	0.05 lb/MMBtu
GA	Rule 391-3-1-.02.(2)(lll)1.[661]	Effective 5/1/00 Fuel-burning equipment 45 county area – ozone May 1 – September 30 each year	30 ppm

[656] https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=2010.

[657] https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=3205.

[658] Applies to units sold, distributed, installed, or offered for sale.

[659] https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download.

[660] RACT for major sources of NOx: https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).

[661] http://rules.sos.ga.gov/gac/391-3-1.

Most stringent NOx Limits of State/Local Rules:

5 ppm (0.0062 lb/MMBtu)……Units ≥75 MMBtu/hr
5–12 ppm (0.0062–0.015 lb/MMBtu) …… Units >2 and <75 MMBtu/hr
20 ppm (0.024 lb/MMBtu)…… Units ≤2 MMBtu/hr

As Table 42 shows, several state and local air pollution control agencies have adopted NOx emission limits for boilers and heaters that reflect the application of low NOx burner technologies, and reflect SCR for units ≥75 MMBtu/hr. These air agencies have thus found that the levels of NOx control listed in Table 42, including NOx limits as low as 5 ppm for larger units, in the range of 5–12 ppm for smaller units, and as low as 20 ppm for very small units, providing relevant examples for states to consider in their second round haze plans to help make reasonable progress towards remedying existing visibility impairment. The fact that these limits could apply to modified units >2 MMBtu/hr means that the states consider retrofit controls to meet the emission limits in Table 42 above to be cost effective, and should also consider the cost effectiveness of retrofitting units >5 MMBtu/hr to meet NOx limits as low as 2–3.5 ppm based on the work being done in the SJVAPCD.

G. SUMMARY – NO_x CONTROLS FOR NATURAL GAS-FIRED HEATERS AND BOILERS

The above analyses and rule data demonstrate that numerous state and local air agencies have found that low NOx burner technology is a cost effective retrofit NOx control for boilers and heaters >5 MMBtu/hr with costs ranging from $545/ton to $5,232/ton. Smaller units ≤5 MMBtu/hr can be replaced with new units with low NOx burner technology at costs ranging from $4,055/ton to $10,809/ton. Low NOx burner technologies can generally meet limits down to 5–6 ppm, with the potential for emerging technologies to meet NOx levels lower than 5 ppm. For most units, including atmospheric units, a blower may be required to mix the fuel and air prior to combustion. It is possible to reach NOx levels of 9 ppm for non-atmospheric units and 12 ppm for atmospheric units without the use of FGR.[662]

Further, SJVAPCD has found that SCR is cost effective for larger units with costs ranging from $1,025/ton to $6,149/ton to meet NOx levels as low as 2.5 ppm. For the lowest NOx limit of 5–6 ppm currently applicable to units under rules adopted by SCAQMD and SJVAPCD, SCR is presumably necessary to meet these limits.

As states evaluate regulation of NOx emissions from boilers and heaters, there are several factors to consider, such as draft type (i.e., atmospheric vs. non-atmospheric), operating capacity factor, and size. Nonetheless, given the numerous local NOx limits in Table 42 above that reflect operation of low NOx burner technology, and SCR for larger units, these controls for units of all sizes should generally be considered as cost effective measures available to make reasonable progress from boilers, reboilers, and

[662] *See, e.g.,* Santa Barbara County APCD 2019 Draft Staff Report.

heaters, given that similar sources have assumed similar costs of control to meet Clean Air Act requirements.

VIII. ADDRESSING VISIBILITY-IMPAIRING EMISSIONS FROM FLARING AND THERMAL INCINERATION OF EXCESS GAS AND WASTE GAS

Gas flaring is a process to combust excess or waste gases from oil wells, gas processing plants, or oil refineries. Flaring is intended as a means of disposal of excess gas as a safety measure and is also done to relieve pressure in gas pipelines. Combustion of excess or waste gas can also be accomplished with thermal incinerators rather than flaring.[663] Combustion of excess gas whether done through flaring or thermal incineration is also a VOC control device, as the combustion of the gas destroys most of the VOCs. However, the extent to which VOC emissions are effectively destroyed depends on the design and operation of the combustion device.

There are several processes associated with oil and gas development in which excess gas is flared or combusted, including the following: during testing of a new oil or gas well, when natural gas co-occurs with a new oil well, at gas pipeline headers and at gas processing plants when needed to relieve pressure, at gas compressor stations to combust vapors captured by a dehydrator unit, at gas processing plants and at oil refineries when an upset occurs or to allow maintenance of equipment, and at gas sweetening plants.[664]

A flare system is a thermal oxidation process using an open flame. It consists of an elevated flare stack through which the waste or excess gas stream flows, where it is combusted at the tip of the stack producing a flame. This is sometimes referred to as a "candlestick" flare. A thermal incinerator, which is also called a direct flame incinerator, thermal oxidizer, or an afterburner, is a thermal oxidation process that occurs in an enclosed combustion chamber. The temperature of the waste gas is raised in the combustion chamber in the presence of oxygen above its autoignition point by passing the gas through a flame which is maintained by the waste gas and auxiliary fuel, and combustion of the waste gas occurs. More specific descriptions of these control devices are provided below. The purpose of both a flare and a thermal incinerator is to combust the excess or waste gas and reduce VOC emissions.

A. FLARING SYSTEM

EPA describes a flare system as follows:

> Flaring is a high-temperature oxidation process used to burn waste gases containing combustible components such as volatile organic compounds (VOCs), natural gas (or

[663] *See* Alberta Energy Regulator, EnerFAQS, Flaring and Incineration, *available at:* https://www.aer.ca/providing-information/news-and-resources/enerfaqs-and-fact-sheets/enerfaqs-flaring.

[664] *See,* e.g., Ohio EPA, Understanding the Basics of Gas Flaring, November 2014, *available at*: https://www.epa.state.oh.us/portals/27/oil%20and%20gas/basics%20of%20gas%20flaring.pdf. *See also* Eman, Eman A., Gas Flaring in Industry: An Overview, Petroleum & Coal 57(5) 532-555, 2015, *available at:* http://large.stanford.edu/courses/2016/ph240/miller1/docs/emam.pdf.

> methane), carbon monoxide (CO), and hydrogen (H_2). The waste gases are piped to a remote, usually elevated location, and burned in an open flame in ambient air using a specially designed burner tip, auxiliary fuel, and, in some cases, assist gases like steam or air to promote mixing for nearly complete (e.g., ≥ 98%) destruction of the combustible components in the waste gas. Note that destruction efficiency is the percentage of a specific pollutant in the flare vent gas that is converted to a different compound (such as carbon dioxide [CO_2], carbon monoxide, or another hydrocarbon intermediate), while combustion efficiency is the percentage of hydrocarbon in the flare vent gas that is completely converted to CO_2 and water vapor. . . .
>
> Combustion requires three ingredients: fuel, an oxidizing agent (typically oxygen in the air), and heat (or ignition source). Flares typically operate with pilot flames to provide the ignition sources, and they use ambient air as the oxidizing agent. The waste gases to be flared typically provide the fuel necessary for combustion. Combustible gases generally have an upper and lower flammability limit. The upper flammability limit (UFL) is the highest concentration of a gas in air that is capable of burning. Above this flammability limit, the fuel is too rich to burn. The lower flammability limit (LFL) is the lowest concentration of the gas in air that is capable of burning. Below the LFL, the fuel is too lean to burn. Between the UFL and the UFL, combustion can occur. Completeness of combustion in a flare is governed by flame temperature, residence time and flammability of the gas in the combustion zone, turbulent mixing of the components to complete the oxidation reaction, and available oxygen for free radical formation. Combustion is complete if all hydrocarbons and CO are converted to CO_2 and water. Incomplete combustion results in some hydrocarbons or CO discharged to the flare being unaltered or converted to other organic compounds such as aldehydes or acids.[665]

Flares, if operated in a manner to provide for complete combustion, are intended to destroy hydrocarbons and VOCs. Flaring also converts methane to CO_2. Both are greenhouse gases, but methane is a more powerful greenhouse gas.[666] EPA indicates that properly operated flares should achieve 98% destruction efficiency of VOCs.[667] However, according to EPA studies, flares "can operate at a wide range of Destruction and Removal Efficiency (DRE)." As a result, although flares are a VOC control device, flares are also a source of VOC emissions especially when not designed or operated in a manner to achieve high levels of DRE. Further, "[s]mall amounts of uncombusted vent gas will escape the flare combustion zone along with products of incomplete combustion,"[668] which can add to VOC emissions as well as methane emitted from the flare. Flaring of natural gas also results in emissions of NOx, as well as particulate matter emissions of carbon particles (soot) and unburned hydrocarbons.

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[665] EPA, VOC Destruction Controls, Chapter 1 Flares, August 2019, at 1-1, *available at:* https://www.epa.gov/sites/production/files/2019-08/documents/flarescostmanualchapter7thedition_august2019vff.pdf.

[666] *See* https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#Learn%20why

[667] *See* EPA, Air Pollution Control Fact Sheet, Flare, EPA-452/F-03-019, *available at:* https://www3.epa.gov/ttn/catc/dir1/fflare.pdf.

[668] Shah, Tejas, Ramboll Environ (EPA Contractor), Greg Yarwood (Ramboll Environ), Alison Eyth (EPA), and Madeleine Strum (EPA), Composition of Organic Gas Emissions from Flaring Natural Gas, August 18, 2017, at 6, *available at:* https://www.epa.gov/sites/production/files/2017-11/documents/organic_gas.pdf.

Flaring is also a significant cause of SO_2 emissions when sour gas or acid gas is flared. Although the sulfur content for gas to be considered sour gas can vary by state, gas with a hydrogen sulfide (H_2S) content of 5.7 milligrams per cubic meter of gas (about 4 ppm) is generally considered to be sour gas.[669] Among other places in the United States, sour gas exists in areas of New Mexico, Texas, Wyoming, and North Dakota.

In terms of air pollution control measures to apply directly to flare design and operation, controls and techniques to ensure or improve DRE are the primary pollution control for natural gas flares. These are discussed further below in Section E.

B. THERMAL INCINERATION

Thermal incineration of gases is generally able to result in more complete combustion due to the greatly improved ability to control fuel and air flow, temperature, turbulence, and residence time.[670] Thus, incineration of excess gases may result in greater destruction of hydrocarbons and lower VOC emissions than if the same amount of gas was flared. As with flaring, while thermal incineration is a VOC control technology, the incineration of waste gas does result in emissions of NOx and some particulate matter as a result of incomplete combustion, along with CO_2. Further, when sour gas or acid gas is combusted in a thermal incinerator, SO_2 will be emitted. In the absence of SO_2 pollution controls, incineration of waste or excess gases may not be the best choice compared to flaring for gas with sulfur compounds, because the elevated height of the flare can allow for greater dispersion of the SO_2 emissions.[671] On the other hand, use of a thermal incinerator to combust excess or waste gas allows for the addition of an acid gas scrubber to remove SO_2 and also could allow for use of the thermal heat produced by the waste gas combustion, whereas those opportunities for SO_2 control and for getting some energy benefit from the combustion of waste gases do not exist with a flare. Further, low NOx combustion controls exist for thermal incinerators. The pollution controls to apply directly to thermal incinerators are discussed further below in Section F.

The best method to reduce/eliminate air emissions from flaring or incineration of excess or waste gas is to avoid the need for combustion of the gases altogether. The options for doing so are discussed further below in Section D.

C. SO_2 EMISSIONS FROM THE DESTRUCTION OF SOUR GAS WASTE STREAMS

For sour gas, the sulfur compounds must be removed to produce pipeline quality natural gas. H_2S is the sulfur compound of most concern in sour gas because the majority of sulfur compounds in sour gas are in the form of H_2S and because it is it is very poisonous, explosive and corrosive. According to the Occupational Safety and Health Administration (OSHA), exposure to H_2S can cause significant eye and respiratory irritation and exposure to high concentrations of H_2S "can cause shock, convulsions, inability

[669] http://naturalgas.org/naturalgas/processing-ng/.
[670] *See*, e.g., EPA, Air Pollution Control Technology Fact Sheet, Thermal Incinerator, EPA-452/F-03-022, *available at:* https://www3.epa.gov/ttnchie1/mkb/documents/fthermal.pdf.
[671] *See* https://www.aer.ca/providing-information/news-and-resources/enerfaqs-and-fact-sheets/enerfaqs-flaring#what.

to breathe, extremely rapid unconsciousness, coma and death."[672] It is also very corrosive to gas pipelines and can be explosive. Thus, H_2S has to be removed from sour gas streams before the gas can be sent into gas pipelines to consumers. H_2S is removed from the gas in gas sweetening plants, usually via an amine process which separates the H_2S and also CO_2 from the natural gas.[673] Since 1985, the EPA's NSPS have required gas sweetening plants with a capacity of more than 2 long tons per day of H_2S in the acid gas to either 1) completely reinject the acid gas stream into oil- or gas-bearing geologic strata or 2) to use a sulfur reduction and removal technology to reduce SO_2 emissions from the acid gas before it is flared or combusted.[674] Sweetening plants that aren't subject to such requirements may be allowed to flare the acid gas stream or incinerate the gas stream, either of which could release very significant quantities of SO_2 emissions, although it is not clear that any such plants continue to operate. However, even for gas sweetening plants required to control the H_2S by reinjecting into the geologic strata or by using a sulfur recovery unit or other control method, SO_2 emissions from flaring or from thermal incineration is of significant concern. For those plants, flaring episodes occur due to malfunctions or due to maintenance or possibly for other reasons.[675] When flared or combusted, the H_2S in the acid gas stream converts to SO_2, which is a significant visibility-impairing pollutant. EPA states that "100 tons or more of SO_2 can be released in [a flaring episode] within a 24-hour period."[676] In the case of flaring of acid gas streams, the only methods to reduce SO_2 emissions directly from flaring acid gas streams at gas sweetening plants are to reduce or eliminate flaring episodes. Methods to reduce such flaring episodes are discussed in the next section.

D. CONTROL MEASURES, TECHNIQUES, AND OPERATING PRACTICES TO PREVENT FLARING OR INCINERATION OF EXCESS OR WASTE GAS

Prevention of flaring/incineration of excess or waste gases is the best method to reduce the air emissions from this source category. It will also prevent NOx, particulate matter, air toxic emissions including formaldehyde, and CO_2 emissions, as well as any VOCs and methane that are not destroyed in the combustion process. Available methods and techniques to reduce flaring or thermal combustion of excess or waste gas are discussed below.

1. REDUCING FLARING AT THE WELL SITE

In 2016, the U.S. Bureau of Land Management (BLM) issued a rule intended "to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production on onshore Federal and Indian (other than Osage Tribe) leases."[677] This rule is often referred to as the "BLM Waste Prevention Rule."

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[672] OHSA Fact Sheet, Hydrogen Sulfide (H_2S), *available at:* https://www.osha.gov/OshDoc/data_Hurricane_Facts/hydrogen_sulfide_fact.pdf.
[673] *See*, e.g., http://operoenergy.com/gas-sweetening-technologies/.
[674] *See* 40 C.F.R. Subparts LLL and OOOO.
[675] *See* EPA, Enforcement Alert, Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases, October 2000, *available at:* https://www.epa.gov/sites/production/files/documents/flaring.pdf.
[676] *Id.*
[677] 81 Fed. Reg. 83,008 (Nov. 18, 2016).

The fact sheet issued by EPA at the time of the rulemaking stated that the rule would phase in, over several years, a flaring limit per development oil well that ratcheted down over time.[678] There were several options for complying with the flaring limits, including: "expanding gas-capture infrastructure (e.g., installing compressors to increase pipeline capacity, or connecting wells to existing infrastructure through gathering lines); adopting alternative on-site capture technologies (e.g., compressing the natural gas or stripping out natural gas liquids and trucking the product to a gas processing plant); or temporarily slowing production at a well to minimize losses until capture infrastructure is installed."[679] The rule also required operators to evaluate opportunities for gas capture before drilling a development oil well, which were to be submitted with an Application for a Permit to Drill and which were to be shared with midstream gas capture companies "to facilitate timely pipeline development. . . ."[680] In 2018, the BLM rescinded the gas capture requirements of the 2016 rule "in favor of an approach that relies on State and tribal regulations and reinstates the NTL-4A standard for flaring in the absence of State or tribal regulations."[681] The 2018 BLM rulemaking describes the NTL-4A standard as the BLM's existing policy from before the 2016 BLM Waste Prevention Rule, which was published in the Federal Register in 1979 (44 Fed. Reg. 76600, Dec. 27, 1979)[682] and "governed venting and flaring from BLM-administered leases for more than 35 years."[683] The BLM has clearly indicated that states could regulate flaring. Indeed, development of the BLM Waste Prevention Rule considered "analogous state requirements related to waste of oil and gas resources," and the BLM "reviewed requirements from Alaska, California, Colorado, Montana, North Dakota, Ohio, Pennsylvania, Utah, and Wyoming."[684] Further, EPA has been requiring the capture and collection of excess gas from the drilling of natural gas wells under the NSPS since 2012.[685]

Thus, there are example state and federal rules[686] and methods that states should adopt, if not already in place, to reduce flaring of gas associated with oil wells, that would not only reduce visibility-impairing pollution from flaring, but that would also reduce air toxics and greenhouse gases emissions as well as ensure that the natural gas produced along with oil at oil wells is utilized as an energy source rather than just flared or combusted to destroy the VOCs.

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[678] *See* BLM Fact Sheet on Methane and Waste Prevention Rule, at 3, *available at:* https://www.doi.gov/sites/doi.gov/files/uploads/methane_waste_prevention_rule_factsheet_final.pdf.

[679] *Id. See also* Clean Air Task Force's publication entitled "Putting Out the Fire: Reducing Flaring in Tight Oil Fields," April 2, 2015, for additional discussion of additional alternatives to flaring excess gas, *available at:* https://www.catf.us/resource/putting-out-the-fire/; and U.S.DOE, Office of Fossil Energy, Natural Gas Flaring and Venting: State and Federal Regulatory Overview, Trends, and *see* Impacts, June 2019, at 50-55 *available at:* https://www.energy.gov/sites/prod/files/2019/08/f65/Natural%20Gas%20Flaring%20and%20Venting%20Report.pdf.

[680] *Id.*

[681] 83 Fed. Reg. 49,184 at 49,188 (Sept. 28, 2018).

[682] 83 Fed. Reg. 49,184 at 49,185 (Sept. 28, 2018).

[683] 83 Fed. Reg. 49,189 at 49,185 (Sept. 28, 2018).

[684] 81 Fed. Reg. 83,008 at 83,019 (Nov. 18, 2016).

[685] 40 C.F.R. Part 60, Subpart OOOO, §60.5375.

[686] The U.S. Department of Energy has a recent report that summarizes the state and federal rules on flaring. *See* U.S.DOE, Office of Fossil Energy, Natural Gas Flaring and Venting: State and Federal Regulatory Overview, Trends, and Impacts, June 2019, at 20-48.

2. REDUCING FLARING AT COMPRESSOR STATIONS, GAS PROCESSING PLANTS, AND GAS SWEETENING PLANTS

As discussed above, flaring at compressor stations and gas processing plants including gas sweetening plants, is often due primarily to plant upsets and maintenance. Flaring of sour gas or acid gas streams at gas sweetening plants can be a significant source of visibility-impairing SO_2, and thus reducing flaring emissions at gas sweetening plants could be an effective reasonable progress measure to address regional haze. Reducing flaring will also reduce the NOx, PM, VOCs, and CO_2 emitted from the flares.

EPA listed the following measure to prevent excess flaring at refineries, and this same approach can be used to identify methods and techniques to reduce flaring at natural gas compressor stations and at gas processing facilities:

> Conduct a root-cause analysis of each flaring incident to identify if any equipment and/or operational changes are necessary to eliminate or minimize that cause so as to reduce or avoid future flaring events. As appropriate, corrective measures should be taken and implemented. If the analysis shows that the same cause has happened before, the incident should not be considered a malfunction and corrective measures should be taken to prevent future occurrences….[687]

In addition, it is imperative to ensure that there is adequate gas handling capacity at the various processing points in a compressor station, gas processing or gas sweetening plant. EPA states that "[r]edundant units can prevent flaring by allowing one unit to operate if the other needs to be shut down for maintenance or an upset. . . ."[688] Thus, adding excess capacity and/or backup units could be very important in reducing the amount of flaring due to upsets.

As part of their evaluation of measures to provide for reasonable progress towards the national visibility goal, states should evaluate the flaring episodes at the compressor station and at gas processing plants, including the collection of data on the length of time of each flaring episode, frequency, and causes. For plants that have more frequent flaring episodes, and especially for those plants flaring sour gas or acid gas streams from a gas sweetening plant, states should evaluate the root causes of upsets that cause flaring episodes to determine if measures, such as improved maintenance or duplicative parts or processing units, can be employed to reduce flaring episodes.

E. POLLUTION CONTROL TECHNIQUES FOR FLARES

EPA has described the control techniques for flares, based on the federal requirements in EPA's New Source Performance Standards (NSPS) (at 40 C.F.R. §60.8) and EPA's National Emission Standards for Hazardous Air Pollutants (NESHAPs) (at 40 C.F.R. §63.11) as follows:

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[687] *See* EPA, Enforcement Alert, Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases, October 2000, at 3 *available at:* https://www.epa.gov/sites/production/files/documents/flaring.pdf.
[687] 81 Fed. Reg. 83,008 (Nov. 18, 2016).
[688] *Id.*

> At a minimum, these [NSPS and NESHAP] rules require flares to be:
>
> - Designed and operated with no visible emissions using EPA [test] Method 22 (except for periods not to exceed 5 minutes in 2 hours);
> - Operated with a flame present at all times, confirmed by the use of a thermocouple or equivalent device;
> - Used only when the net heating value of the gas to be combusted is 300 BTU per standard cubic foot (BTU/scf) or greater (if the flare is steam- or air-assisted), or 200 BTU/scf or greater (if the flare is nonassisted); and
> - Designed for and operated with an exit velocity less than 60 feet per second (f/sec). An exit velocity of greater than 60 ft/sec but less than 400 ft/sec may be used if the net heating value of the gas being combusted is sufficiently high.[689]

Other requirements that must be met include that the flare must be operated at all times in a manner consistent with good air pollution control practices for minimizing emissions, and that flaring operations must be monitored to ensure they are operated and maintained according to their design.[690] EPA has listed several other more detailed guidelines to ensure flares are properly operated.[691] Proper training of employees is also an important part of ensuring the flares are properly operated. States must require documentation of each flaring episode to ensure that the flaring regulations of the NSPS and NESHAPs have been complied with, as well as to ensure that adequate records of the amount of gas flared and causes of flaring are maintained and reported.

The above operating standards are required for all flaring. Alternatives to flaring include 1) gas capture to decrease or eliminate flaring as discussed above, or 2) combusting the gas in a thermal incinerator which can provide for greater destruction of VOC emissions. Also, additional air pollution controls can be used at an incinerator, as is discussed below.

F. POLLUTION CONTROL TECHNIQUES FOR THERMAL INCINERATION OF EXCESS OR WASTE GAS

As discussed above, waste gases or excess gas can be disposed of via thermal incineration rather than a flare. EPA describes a thermal incinerator, or a thermal oxidizer, as follows:

> Incineration, or thermal oxidation is the process of oxidizing combustible materials by raising the temperature of the material above its auto-ignition point in the presence of oxygen, and maintaining it at high temperature for sufficient time to complete combustion to carbon dioxide and water. Time, temperature, turbulence (for mixing), and the availability of oxygen all affect the rate and efficiency of the combustion process. These factors provide the basic design parameters for VOC oxidation systems (ICAC, 1999).

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[689] *See* EPA, Enforcement Alert, EPA Enforcement Targets Flaring Efficiency Violations, August 2012, at 1, *available at:* https://www.epa.gov/sites/production/files/documents/flaringviolations.pdf.
[690] *Id.* at 2; see also 40 C.F.R. §63.172(e) and 60.482-10.
[691] *See*, e.g., EPA, Enforcement Alert, EPA Enforcement Targets Flaring Efficiency Violations, August 2012, at 3.

> A straight thermal incinerator is comprised of a combustion chamber and does not include any heat recovery of exhaust air by a heat exchanger (this type of incinerator is referred to as a recuperative incinerator).
>
> The heart of the thermal incinerator is a nozzle-stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. Upon passing through the flame, the waste gas is heated from its preheated inlet temperature to its ignition temperature. . . . The required level of VOC control of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. The nominal residence time of the reacting waste gas in the combustion chamber is defined as the combustion chamber volume divided by the volumetric flow rate of the gas. . . . .[692]

EPA indicates that thermal incinerators can achieve 98% to 99.9999% destruction of VOCs.[693] However, thermal incinerators typically require auxiliary fuel to preheat the waste gas and sustain the heat necessary for destruction of VOCs.[694] The high temperature reaction necessary in an incinerator to destroy the VOC and air toxic emissions can result in increased NOx emissions. To limit NOx emissions, low NOx burners or other low NOx processes are available control measures to integrate into the thermal incinerator to limit NOx emissions.[695] Thus, for any thermal incinerators or thermal oxidizers, low NOx burners or other low NOx emission systems should be installed to minimize NOx emissions from the thermal incinerator.

It is important to note that thermal incinerators can be used at gas sweetening plants along with acid gas scrubbers to remove the SO_2 that is formed from combusting the H_2S in the acid gas. Such a system could potentially be used as an SO_2 control,[696] or it could be used as a backup system for a sulfur recovery unit when it is down due to malfunction, maintenance, or during startup or shutdown.[697] This method of control could greatly reduce if not eliminate the SO_2 emissions that occur at gas sweetening

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[692] EPA, Air Pollution Control Technology Fact Sheet, Thermal Incinerator, EPA-452/F-03-022, at 4, *available at:* https://www3.epa.gov/ttnchie1/mkb/documents/fthermal.pdf.

[693] *Id.* at 5.

[694] *Id. See also* EPA, Control Cost Manual, Section 3, Chapter 2 – Incinerators and Oxidizers, at 2-3 to 2-4, *available at:* https://www.epa.gov/sites/production/files/2017-12/documents/oxidizersincinerators_chapter2_7theditionfinal.pdf.

[695] *See*, e.g., Zeeco Products & Applications, Incinerators & Thermal Oxidizers Multi-Stage Low-NOx Incinerator/Thermal Oxidizer, *available at:* https://www.zeeco.com/incinerators/incinerators-therm-ox-multi-stage.php. *See also* AERON, Thermal Oxidation/Incineration Systems, Ultra-Low Emissions Systems, *available at:* http://www.aereon.com/enclosed-combustion-systems/ultra-low-emissions-systems/certified-ultra-low-emissions-burner-ceb.

[696] *See*, e.g., AERON, Thermal Oxidation/Incineration Systems, Tail Gas Incineration Units, which discusses acid flue gas scrubbers as an available option, *available at:* http://www.aereon.com/enclosed-combustion-systems/thermal-oxidationincineration-systems/tail-gas-incineration-units.

[697] *See* Envitech, Industrial Gas Cleaning Systems, Air Pollution Control Innovations, Refinery Sulfur Recovery Unit (SRU) SO_2 Scrubber for Startup, Shutdown, and Malfunctions, *available at:* https://www.envitechinc.com/air-pollution-control-innovations/refinery-sulfur-recovery-unit-sru-so2-scrubber-for-startup-shutdown-and-malfunctiong-post-title-here.

facilities when the gas injection well or sulfur recovery unit is not in operation due to malfunctions or maintenance.

In many respects, combusting of waste gases and/or excess gas in a thermal incinerator seems more preferable from an air pollutant perspective than flaring, because thermal incineration will likely result in a greater destruction efficiency of VOCs and because control options exist for limiting emissions of NOx and of SO_2 (to the extent that sour gas or an acid gas stream is what was being flared). Further, there could be an option of gathering and routing excess gas emission from multiple points to a centralized thermal incinerator. Moreover, continuous emission monitoring systems (CEMS) could be installed in the thermal oxidizer stack to provide valuable actual emissions data due to the combustion of waste or excess gases, including information to ensure that optimal VOC destruction efficiency is achieved.

However, the need for auxiliary fuel in thermal combustion means more CO_2 will be emitted than if the gas stream was flared. Yet, there are options for thermal incinerators that recover the waste heat, which are called recuperative oxidizers or regenerative oxidizers.[698] The recovered waste heat can be used to preheat the incoming air which would reduce the amount of supplemental fuel required.[699]

To sum up, use of a recuperative or regenerative thermal incinerator (thermal oxidizer) with low NOx combustion controls, CEMs, and an acid gas scrubber if necessary, seems to be a preferable alternative to flaring of waste gas streams. Such a system would provide better control of VOCs, reduce NOx emissions from combustion of the waste gas via the use of low NOx combustion controls, and provide the ability to add an acid gas scrubber to remove SO_2 (which is a control option that does not exist for flares).

G. SUMMARY – BEST OPTIONS FOR CONTROLLING EMISSIONS DUE TO FLARING OR INCINERATION OF EXCESS OR WASTE GAS

Based on the above analysis, it seems evident that prevention of flaring through the collection of excess gas is the most beneficial option for reducing emissions from flaring. Capturing and using the natural gas that is produced at oil wells would ensure that the energy value of the gas is not wasted by being combusted in a flare or in an incinerator, and it is very likely that the end user of the gas would at least be using some level of NOx and VOC control.

Thermal incineration should be considered in lieu of flaring for waste gases due to the pollution controls for NOx and SO_2 that are available and because of the improved operation and VOC destruction. Moreover, use of a thermal incinerator provides the opportunity to monitor and accurately track emissions from the combustion of waste or excess gases with the use of CEMS.

At gas processing facilities including gas sweetening plants, it is important that the causes of flaring episodes be documented and assessed to determine any changes in operations, training, and/or in equipment that may be needed to reduce plant upsets and maintenance during which flaring occurs due

[698] EPA, Air Pollution Control Technology Fact Sheet, Thermal Incinerator, EPA-452/F-03-022, at 5.
[699] *Id.*

to the unavailability of plant equipment to process the gas stream. As stated above, adding excess capacity and/or backup units could be very effective in reducing the amount of flaring due to upsets. Proper maintenance of equipment is also key, as is appropriate training of staff to minimize flaring episodes due to maintenance and upsets.

In general, states should ensure that their rules require companies to document all flaring episodes, including the cause, duration of the flaring, flue gas flow, actions taken to stop the flaring, and emission estimates, and to submit such documentation to the state or local air agency in a timely manner. This data will best enable states to develop appropriate rules and procedures to limit the various causes of flaring emissions within its state.

Overall, the goal of state programs to address flaring emissions should be to minimize flaring to the maximum extent possible. However, for those situations when flaring does occur, it is imperative that the flares be operated in accordance with NSPS and NESHAP requirements, and that the flares are operated and maintained in accordance with their design. Moreover, to ensure these requirements are being met and to ensure that flaring is minimized to the maximum extent possible, the state or local air agencies must conduct thorough oversight into the causes of flaring episodes, to ensure that the facility is being maintained and operated in a manner to minimize all flaring episodes to the extent possible.

Appendix F: Federal Land Manager Formal Consultation Supporting Documentation

F.1 New Mexico Environment Department Communications to Federal Land Managers during 60-day formal review period

Supporting documentation for New Mexico Environment Department (NMED) communication to FLMs during formal FLM review period is provided below. The following documents are included in this section (in reading order):

- NMED Initiation of Formal Review Period (5/20/24)
- NMED - FLM Draft - Regional Haze SIP Overview and Summary (6/6/24)

From:	Jones, Mark, ENV
To:	Allen, Tim; Souther, John - FS, AZ; Kerry Jones; Rose, Anita -FS; Peters, Melanie; Stacy, Andrea; Debra Miller; Shepherd, Don; Devore, Lisa M; Salazer, Holly
Cc:	Miller, Kenneth, ENV; Sanchez, Alex, ENV; Butt, Neal, ENV; Peters, Eric, ENV; Olson, Kirby, ENV; Vigil, Christopher J, ENV; Smith, Morgan A.; Lehner, Catalina L.
Subject:	NMED Draft Regional Haze SIP Revision - FLM 60-day Formal Consultation Review Draft
Date:	Monday, May 20, 2024 12:39:00 PM
Attachments:	2024-05-20_NMED Draft Regional Haze SIPr Narrative [External Review Draft].pdf 2024-05-20_NMED Draft Regional Haze SIPr Appendix C [External Review Draft].pdf

---

Dear representatives from the U.S. Fish and Wildlife Service, U.S. Forest Service, and the U.S. National Park Service,

The NMED Regional Haze planning team has completed a draft Regional Haze SIP revision for the second planning period (2019-2028). We are providing it to you today, May 20, 2024, to initiate the 60-day Federal Land Manager (FLM) consultation period. A copy of the draft SIP revision and the appendix containing the four-factor analysis technical support document (TSD) are attached to this email. Our team plans to send a follow-up email with a link to a shared folder which will include the attached drafts as well as additional technical documentation.

We would like to set up a time to meet with you via Teams in May or early June (or whatever time is most useful and convenient to you) to provide an overview and summary of our draft plan. Our team is open to additional meetings and/or periodic check-ins during the 60-day review period to discuss any topics of interest. You're also welcome to reach out with questions at any time. For this 60-day formal consultation period, we request that you provide any comments on the draft SIP revision by July 21, 2024.

I'd also like to take this opportunity to introduce Eric Peters, the new manager of the NMED Air Quality Bureau—Control Strategies Section. Please include him in communications related to Regional Haze planning moving forward.

Thank you,

Mark

Mark Jones | Environmental Analyst
Regional Haze Team - Technical Lead
NMED Air Quality Bureau | www.env.nm.gov/air-quality/
mark.jones@env.nm.gov | (505) 629-6626

Science | Innovation | Collaboration | Compliance

New Mexico Environment Department



Overview of Draft Regional Haze SIP Revision for Federal Land Managers

NMED Regional Haze Planning Team
June 6, 2024

Agenda

- Introductions
- Background
- Navigating the Draft SIP Revision Document
- Key SIP Elements
  - Source Selection
  - FFA and Control Measures Determinations
  - Long-Term Strategy
  - Salt Creek Robust Demonstration
- Discussion

NMED Regional Haze Planning Team

Project Staff:

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- Ken Miller, Planner
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- Alex Sanchez, Planner
  - 505-629-7891; alex.sanchez@env.nm.gov

NMED Regional Haze Planning Website:

https://www.env.nm.gov/air-quality/reg-haze/

Background


Mandatory Class I Areas
North Cascades
Pasayten
Olympic
Glacier Peak
Cabinet Mountains
Glacier
Alpine Lakes
Mount Rainier
Goat Rocks
Mount Adams
Mission Mountains
Bob Marshall
Scapegoat
Medicine Lake
UL Bend
Lostwood
Mount Hood
Hells Canyon
Gates of the Mountains
Theodore Roosevelt
Mount Jefferson
Eagle Cap
Anaconda Pintler
Mount Washington
Three Sisters
Selway-Bitterroot
Diamond Peak
Strawberry Mountain
Yellowstone
North Absaroka
Kalmiopsis
Crater Lake
Red Rock Lakes
Mountain Lakes
Sawtooth
Grand Teton
Washakie
Marble Mountain
Gearhart Mountain
Teton
Redwood
Lava Beds
Craters of the Moon
Fitzpatrick
Wind Cave
Badlands
South Warner
Bridger
Thousand Lakes
Jarbidge
Caribou
Lassen Volcanic
Yolla Bolly-Middle Eel
Point Reyes
Desolation
Mokelumne
Mount Zirkel
Rawah
Rocky Mountain
Flat Tops
Emigrant
Hoover
Yosemite
Ansel Adams
Capitol Reef
Arches
Eagles Nest
Maroon Bells - Snowmass
Pinnacles
Kaiser
John Muir
Bryce Canyon
West Elk
Black Canyon
Ventana
Sequoia / Kings Canyon
Zion
Canyon-lands
La Garita
Great Sand Dunes
Domeland
Grand Canyon
Mesa Verde
Weminuche
San Rafael
Wheeler Peak
San Pedro Parks
Sycamore Canyon
San Gabriel
Cucamonga
Pecos
San Gorgonio
Bandelier
San Jacinto
Pine Mountain
Petrified Forest
Agua Tibia
Joshua Tree
Mazatzal
Sierra Ancha
Mount Baldy
Bosque del Apache
Wichita Mountains
Superstition
Salt Creek
Galiuro
Gila
White Mountain
Saguaro
Chiricahua
Carlsbad Caverns
Guadalupe Mountains
Big Bend
Voyageurs
Isle Royale
Boundary Waters Canoe Area
Rainbow Lake
Seney
Roosevelt Campobello
Moosehorn
Acadia
Great Gulf
Presidential Range-Dry River
Lye Brook
Brigantine Wilderness
Dolly Sods
Otter Creek
Shenandoah
James River Face
Mammoth Cave
Mingo
Hercules-Glades
Great Smoky Mtns
Linville Gorge
Swanquarter
Upper Buffalo
Joyce Kilmer-Slickrock
Shining Rock
Cohutta
Caney Creek
Sipsey Wilderness
Cape Romain
Wolf Island
Okefenokee
Bradwell Bay
Saint Marks
Breton
Chassahowitzka
Everglades
Denali
Bering Sea
Tuxedni
Simeonof
Haleakala
Hawaii Volcanoes
Virgin Islands
1/2007
Produced by NPS Air Resources Division
0 125 250 500
Kilometers
NPS Unit
USFS Unit
FWS Unit

Navigating Draft SIP Document

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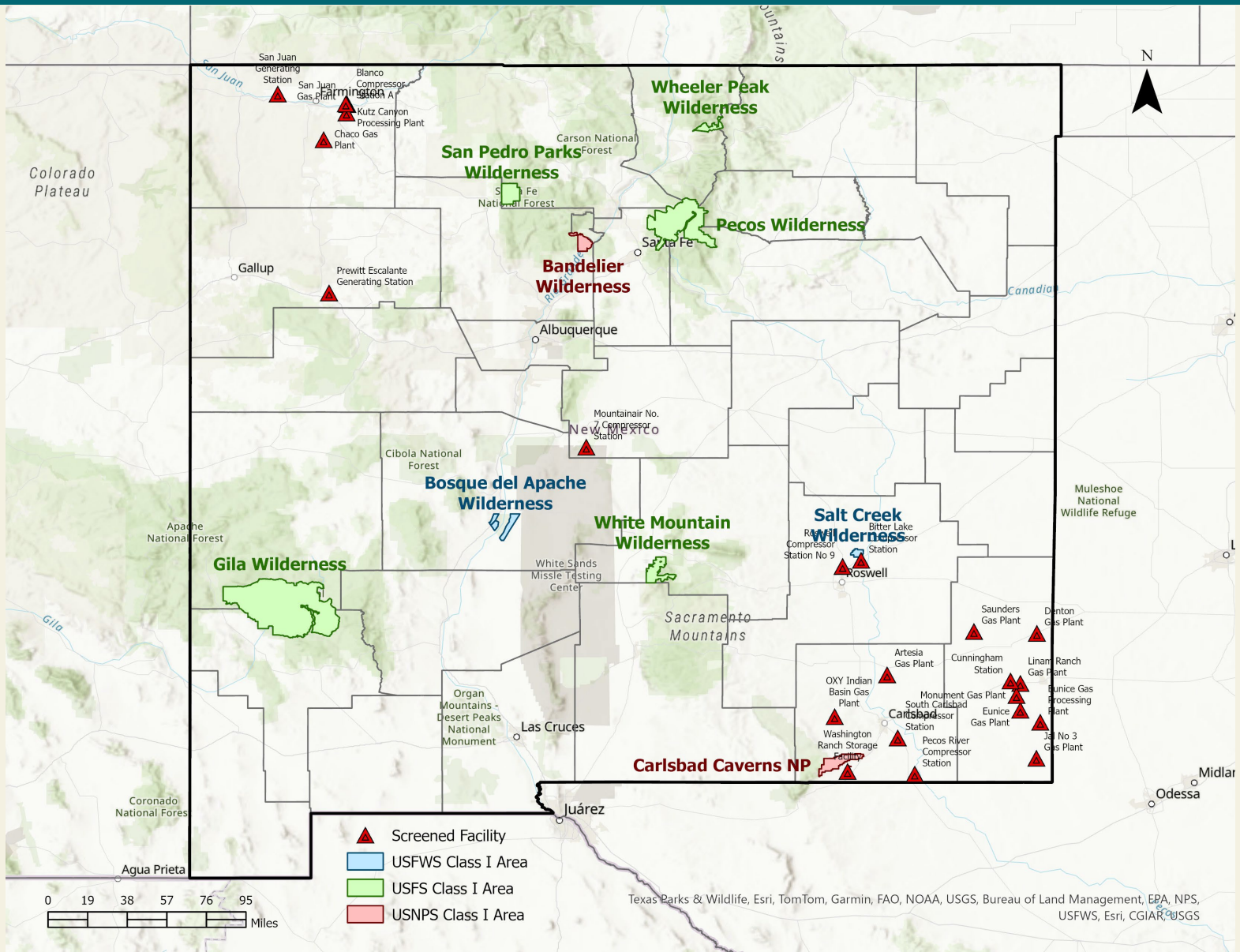
Key SIP Elements

SOURCE SELECTION

Source Selection

- Tier 1: Facility Selection
  - Title V Sources with Q/d Score ≥ 5.6
  - 23 Facilities in NMED's Jurisdiction
  - 1 Facility in Bernalillo County (EHD's Jurisdiction)
- Tier 2: Unit Selection
  - PTE (NO_X or SO_2) ≥ 10 pph
  - 133 Individual Emissions Units

Source Selection



Source Selection

	2SLB RICE	4SLB RICE	4SRB RICE	Turbines	Boilers	ATS	Total
Denton Gas Plant	-	-	-	-	-	1	1
Artesia Gas Plant	-	-	-	-	-	1	1
Eunice Gas Plant	-	-	-	5	-	1	6
Linam Ranch Gas Plant	6	-	-	4	-	1	11
Blanco Compressor Station A	14	-	-	-	-	-	14
Pecos River Compressor Station	-	-	-	3	-	-	3
Washington Ranch Storage Facility	2	-	-	-	-	-	2
Blanco C&D Compressor Station	-	-	-	3	-	-	3
Chaco Gas Plant	3	-	-	5	-	1	9
South Carlsbad Compressor Station	-	-	-	2	-	-	2
Jal #3 Gas Plant	2	-	-	-	-	1	3
Mountainair Compressor Station No. 7	-	3	2	-	-	-	5
Roswell Compressor Station No. 9	-	2	-	-	-	-	2
Kutz Canyon Processing Plant	-	-	3	8	-	-	11
San Juan Basin Gas Plant	-	-	-	7	-	1	8
Bitter Lake Compressor Station	2	-	-	-	-	-	2
Indian Basin Gas Plant	-	-	-	3	-	1	4
San Juan Generating Station	-	-	-	-	2	-	2
Eunice Gas Processing Plant	13	-	-	-	2	1	16
Monument Gas Plant	7	-	-	-	-	1	8
Saunders Gas Plant	9	-	3	-	-	1	13
Prewitt Escalante Generating Station	-	-	-	-	3	-	3
Cunningham Station Power Plant	-	-	-	2	2	-	4
Total	58	5	8	42	9	11	133

Key SIP Elements

FFA and CONTROL MEASURES DETERMINATIONS

FFA and Control Measures

- FFA Performed for 91 Emissions Units
- All Technically Feasible Controls Evaluated
- Primary Consideration = Cost of Compliance
- $10,000/ton Cost Effectiveness Threshold
- Most Effective Control at or Below Threshold Selected
- Details Provided in Draft Technical Support Document (Appendix C)

Key SIP Elements

LONG-TERM STRATEGY

Long-Term Strategy

- New Controls on 44 Emissions Units
  - LEC, DLN, SCR, Replacement
- Permanent Retirement of 34 Emissions Units
- Continued Use of In-Place Controls on 7 Emissions Units
- Continued Use of AGI Well + Redundant Compression on 4 Amine Treatment Systems

Long-Term Strategy

Facility	Estimated NO_X Reductions (ton/yr)	Estimated SO_2 Reductions (ton/yr)
Denton Gas Plant	---	708.0
Artesia Gas Plant	---	---
Eunice Gas Plant	321.6	1,392.9
Linam Ranch Gas Plant	37.3	---
Blanco Compressor Station A	93.8	---
Pecos River Compressor Station	205.4	---
Washington Ranch Storage Facility	---	---
Blanco C&D Compressor Station	---	---
Chaco Gas Plant	118.3	---
South Carlsbad Compressor Station	123.4	---
Jal #3 Gas Plant	25.1	154.4
Mountainair Compressor Station No. 7	1,284.5	---
Roswell Compressor Station No. 9	644.6	---
Kutz Canyon Processing Plant	418.1	---
San Juan Basin Gas Plant	159.2	---
Bitter Lake Compressor Station	---	---
Indian Basin Gas Plant	100.5	---
San Juan Generating Station	7,007.4	1,558.5
Eunice Gas Processing Plant	1,779.9	308.2
Monument Gas Plant	409.0	112.2
Saunders Gas Plant	632.0	284.8
Prewitt Escalante Generating Station	2,313.4	829.2
Cunningham Station Power Plant	1,168.2	---
Total	16,841.7	5,348.2

Key SIP Elements

SALT CREEK ROBUST DEMONSTRATION

Robust Demonstration

- Only Area Above the URP Glidepath
- Monitoring shows Improving Visibility, Attainment of Endpoint in 2050
- LTS Includes Significant Reductions from Sources Potentially Contributing to Impairment
  - Approx 5,400 tons NO_X and 3,000 tons SO_2 Reductions from Facilities in the Permian Basin
- Additional Emissions Reductions Due to Compliance and Enforcement Settlements
  - Matador, Ameredev

Discussion

Questions?

F.2 Formal Federal Land Manager Comments

Supporting documentation for New Mexico Environment Department (NMED) formal consultation with Federal Land Managers is provided below. The following documents are included in this section (in reading order):

- U.S. Forest Service Formal Comments (7/24/24)
- U.S. National Park Service Formal Comments (7/26/24)

United States Department of Agriculture **Forest Service** **Southwestern Region Regional Office**

333 Broadway SE
Albuquerque, NM 87102
505-842-3292
Fax: 505-842-3800

File Code: 2580
Date: July 19, 2024

Dana Bahar
Deputy Director, Environmental Protection Division
New Mexico Environment Department
1190 St. Francis Drive
PO Box 5469
Santa Fe, NM 87505

Dear Ms. Bahar:

On May 20th, 2024, the Air Quality Bureau of the New Mexico Environment Department (NMED) submitted a draft Regional Haze State Implementation Plan describing your proposal to continue improving air quality by reducing regional haze impacts at mandatory Class I airsheds across the region. We appreciate the opportunity to work closely with the NMED through the initial evaluation, development, and subsequent review of this plan. Cooperative efforts such as these ensure that, together, we will continue to make progress toward the Clean Air Act's goal of natural visibility conditions for Class I areas.

This letter acknowledges that the U.S. Department of Agriculture, U.S. Forest Service, has received and conducted a substantive review of your proposed draft Regional Haze State Implementation Plan. This review satisfies your requirements under the federal regulations 40 C.F.R. § 51.308(i)(2). Please note, however, that only the U.S. Environmental Protection Agency (EPA) can make a final determination about the document's completeness, and therefore, only the EPA has the authority to approve the document.

We are satisfied with the document as provided and offer no suggestions for change beyond the informal suggestions to clarify language that were shared via email on July 19th, 2024. For further information, please contact Anita Rose (anita.rose@usda.gov).

We appreciate the opportunity to work closely with the New Mexico Environment Department. The Forest Service compliments you on your hard work and dedication to significant improvement in our nation's air quality values and visibility.

Sincerely,

MICHIKO J. MARTIN
Regional Forester

cc: Anita Rose, anita.rose@usda.gov

National Park Service (NPS) Technical Comments on the State Of New Mexico's Draft Regional Haze Implementation Plan Revision Second Planning Period (2019-2028)

July 26, 2024

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1 Introduction

The NPS appreciates this opportunity to provide Federal Land Manager (FLM) consultation comments on New Mexico's proposed Regional Haze State Implementation Plan (SIP) for the Second Planning Period. The New Mexico Environment Department, Air Quality Bureau (NMED) held a consultation meeting with the NPS on July 11, 2024. These written technical comments support and document the preliminary feedback provided by the NPS during the July 11 consultation meeting. Overall, the NPS finds that NMED has developed a clear, concise, and well-organized draft SIP that proposes to implement significant emission reductions at 13 facilities. As described below, the NPS supports many of the control determinations presented in the draft SIP and agrees that ongoing emission reductions are necessary to advance progress toward the national regional haze visibility goal. NPS conclusions and recommendations, including facility-specific feedback, are provided to further strengthen the SIP (see Sections 2 and 3).

New Mexico is home to two NPS-managed Class I areas: Bandelier National Monument and Carlsbad Caverns National Park. The NPS values clean air and clear views and recognizes they are essential to park visitor experience and the very purpose of federal Class I areas. Visitors from around the world come to these special places to explore the wonders of the desert southwest and gaze into distant galaxies visible through the parks' dark night skies. The NMED's consideration and implementation of air pollution emission controls shows the state's commitment to improving regional haze.

The emission reductions proposed in the SIP are necessary to improve visibility in New Mexico's Class I areas. A recent review of visibility impairment rankings by the NPS shows that the shared visibility monitor of Carlsbad Caverns and Guadalupe Mountains National Park in Texas is the fourth most impaired NPS Class I area site in the country. Further, monitoring data over the past ten years show that visibility on the most impaired days in New Mexico parks is not improving. In fact, both Bandelier National Monument and Carlsbad Caverns National Park would have been above the uniform rate of progress (URP) glidepath had the URP not been adjusted for international and prescribed fire emissions.

The NPS appreciates the steps NMED is proposing to reduce haze-causing pollution and address regional haze in national parks in this planning period. The NPS looks forward to ongoing consultation with NMED and welcomes opportunities for further dialogue as New Mexico progresses towards a final SIP.

2 Overarching Feedback

2.1 FLM Consultation

To date, the NPS finds that NMED's process for FLM engagement has been exceptional. The NMED initiated early and ongoing dialog with the FLM agencies, including the NPS, and NMED requested FLM feedback on key SIP components as they were under development rather than after they were completed (e.g., source selection). The NMED incorporated NPS suggestions into the draft SIP throughout the planning process.

The NPS appreciates these early and ongoing opportunities to share agency expertise. These steps ensure that the FLMs can "*meaningfully inform"* the long-term strategies incorporated into the SIP as required in 40 C.F.R (i)(2). The NPS finds that the current NMED approach meets the spirit, intent, and letter of the law with respect to FLM consultation and coordination requirements. The NPS encourages NMED to continue this approach by substantively addressing the NPS conclusions and recommendations provided in this document. As a reminder, the CAA requires that the state *shall include a summary of the conclusions and recommendations of the Federal land managers in the notice to the public* (Section 169A, codified at 42 U.S.C. §7491 (d)).

2.2 Source Selection

Selecting the pollutants and sources for evaluation are foundational components of the regional haze planning process. A robust and thorough source selection approach is necessary to develop an adequate long-term strategy and reasonable progress determinations. The NPS finds that the NMED approach to source selection in the second implementation period was sufficiently robust and supports NMED's final list of 23 facilities evaluated in the SIP.

The NMED source selection approach relied on surrogate visibility impairment metrics to identify sources potentially contributing to visibility impairment in New Mexico and nearby Class I areas. This is consistent with EPA recommendations provided in the 2019 regional haze implementation guidance document and the 2016 draft regional haze implementation guidance document, which both note that surrogate metrics are an appropriate method to identifying sources for analysis. The NMED initially used an emissions over distance approach (Q/d) to select stationary point sources for analysis. This approach sums the quantity of precursor pollutants emitted by a facility (Q in tons per year of sulfur dioxide (SO_2) plus nitrogen oxides (NO_x)) and divides it by the distance from the facility to the nearest Class I Area (distance(d) in kilometers (km)).

The NMED substantiated their Q/d results using the Weighted Emissions Potential (WEP) and Area of Influence (AOI) products developed by the Western Regional Air Partnership (WRAP). The WRAP WEP-AOI results were made available for use in regional haze planning in September 2020. The WRAP WEP-AOI analysis was performed for the most impaired days (MID) during each year of the five-year period from 2014 through 2018 at 76 Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites representing 116 Class I Areas in the contiguous WRAP region as well as neighboring states.

The NPS concludes that NMED identified a reasonable number of sources by capturing 80% of the stationary source SO_2 plus NO_x emissions contributing to visibility impairment in Class I areas affected by New Mexico emissions. The 80% threshold is consistent with recommendations in the 2016 EPA draft regional haze guidance and NPS recommendations for source selection. The NMED and City of Albuquerque Environmental Health Department (EHD) jointly selected 24 facilities statewide for reasonable progress analysis (one in Albuquerque and 23 in the rest of New Mexico) and evaluated both SO_2 and NO_x emission reduction opportunities at these facilities. The final list included all NPS-recommended facilities. The NPS appreciates that NMED included San Juan Basin Gas Plant and Blanco Compressor Stations A, C, and D. These compressor stations are considered a single facility for the purposes of New Source Review (NSR) and their emissions impact Mesa Verde National Park in Colorado.

Finally, the NPS notes that oil and gas non-point sources in New Mexico were estimated to have emitted over 50,000 tons per year in 2014 - 2018(see Table 5-11 in the SIP). In addition, emission inventories developed in support of New Mexico's Oil and Gas Sector Ozone Precursor Pollutants Rule demonstrate that oil and gas non-point sources emissions have further increased since 2018. The NPS recommends that NMED not only evaluate oil and gas non-point sources but also additional source category-wide rules as explained in Section 3.11.

2.3 Visibility Benefit and the URP

The NMED appropriately declined to consider visibility benefit of potential control measures in the individual facility reasonable progress determinations. From the SIP:

> *NMED did not directly consider the visibility benefits of potential control measures when making its control determinations. EPA has consistently stated that the CAA and Regional Haze Rule allow, but do not require, states to consider visibility alongside the four statutory factors when making control determinations.161 NMED's approach is based on the assumption that substantial reductions in emissions of NO_X and SO_2 will translate into visibility benefits.*

The Clean Air Act (CAA) specifies that reasonable progress comes from emission reduction measures incorporated into a state's long-term strategy and that, after the first planning period, control determinations are to be based on the *four statutory factors*, which are provided Section 169A of the CAA:

> *(1)* ***in determining reasonable progress*** *there shall be taken into consideration the costs of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements. [§7491 (g)(1)]*

According to the CAA, the regulations drafted by EPA to govern SIP development shall:

> *[R]equire each applicable implementation plan for a State . . . to contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal specified in subsection (a) of this section. [§7491 (b)(2)]*

Congress omitted visibility benefit from the definition for determining reasonable progress in subsequent rounds of haze planning because later planning periods were meant to be different from the first planning round Best Available Retrofit Technology (BART) provisions. Therefore, the NPS supports NMED's decision that visibility benefit should not be used as a fifth-factor to dismiss controls that would otherwise be reasonable based on the four statutory factors.

2.4 Criteria Used in Reasonable Progress Determinations

The NPS finds that the New Mexico four factor analysis reviews generally follow EPA guidance and are well organized, consistent, and thorough. The NMED clearly described the criteria used to (1) identify the sources evaluated and (2) take the four factors into consideration in selecting the measures for inclusion in the long-term strategy. Notably, NMED heavily weighted the costs of control in the final facility-specific reasonable progress determinations and used a cost-effectiveness threshold (CETV) of $10,000/ton of pollutant reduced. This approach is consistent with EPA recommendations that suggest cost is frequently the determining factor in control technology reviews[1]. Further, NMED thoroughly documented the rationale for selecting this CETV in the SIP, which was based on a statistical analysis of control cost information and determinations:

> *NMED chose to apply a cost effectiveness threshold value (CETV) to remove control measures deemed not cost-effective from further consideration. To determine its CETV, which represents the cost effectiveness value above which further incremental reductions in NO_x emissions are insufficient to justify more expensive controls, NMED catalogued the available controls, identified the most effective controls available at potential CETVs ranging from $1,000/ton to $20,000/ton, and then determined the estimated total and incremental NO_x reductions provided by the most effective controls at each potential CETV. NMED then binned the incremental NO_x reductions and performed a segmented linear regression on a plot of the estimated total NO_x reductions with breakpoints at the bin edges. The results are shown in Figure 7-1. The binning and associated regression analysis showed that incremental NO_x reductions were significant up to $10,000/ton and then decreased by approximately 50%, with an even larger decrease at $14,000/ton. This led NMED to identify $10,000/ton as its CETV.*

[1] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, EPA-457/B-19-003, August 20, 2019

The NPS supports NMED's approach. The NPS also notes that after the initial analysis, NMED categorically excluded electrification from further consideration (SIP Section 7.4.2). The NMED subsequently updated its CETV analysis using revised cost estimates that exclude electrification and found that the breakpoints in cost-effectiveness changed. From the draft SIP:

> *Notably, the breakpoint at $10,000/ton observed in the initial analysis is missing in the updated analysis due to incremental NO_x reductions being fairly consistent up to $14,000/ton, at which point they decrease significantly, as they did in the initial analysis.*

Given this, the NPS recommends that NMED consider additional controls that are estimated to be right at or just above the New Mexico $10,000/ton CETV (as described in NPS facility-specific feedback provided in Section 3). This recommendation is consistent with the NMED finding that incremental NO_x reductions are consistent (and may be cost-effective) up to $14,000/ton. It is also consistent with EPA guidance which recommends that control costs are typically estimated at an accuracy level of plus or minus 30%.[2]

2.5 Overarching SCR Review Concerns

The NMED evaluated the costs and/or feasibility of using selective catalytic reduction (SCR) to control NO_x emissions for several of the facilities considered in the SIP. The NMED made several general assumptions in the SCR cost analyses, which include:

1) a "margin of safety" for SCR applications, applied as a cushion that was calculated outside of the control cost estimate,
2) dismissal of SCR due to space constraints at several facilities without detailed analyses and justification, and
3) additional operator costs above what is already included in the EPA Control Cost Manual (CCM) workbooks for SCR.

The NPS is not aware of these types of general assumptions being used for the other technically feasible NO_x control technologies evaluated. As described below, the NPS recommends that NMED remove these blanket assumptions. If NMED does not choose to remove such assumptions then, where appropriate, the NPS recommends that NMED provide additional site-specific documentation and justification as to why these assumptions are applicable to the affected facilities.

With respect to "margin of safety," NMED established this threshold to address concerns regarding *building and/or exhaust system modifications which can easily cost as much if not more than the SCR equipment itself* (SIP Section 7.4.2). In this case, NMED is setting the "margin of safety" value based on the total capital investment (TCI) at $10,000/ton versus the calculated TCI for the unit. *If the TCI margin of safety exceeded 100%, then TCI could increase*

[2] EPA Control Cost Manual 7th Edition, Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, p. 6.

twofold and the cost effectiveness would still be at or below $10,000/ton (staff-to-staff communications with NMED, July 16, 2024). The NPS has several concerns with this approach:

1) Building costs and exhaust system modifications (e.g., balance of plant costs) are already built into the CCM TCI estimates. The CCM default retrofit factor value of 1.0 includes a 25% increase over a "greenfield" application to account for necessary plant modifications and applies to most retrofits of "average difficulty." Adequate and thorough documentation should be provided to justify retrofit factors greater than 1.0 (up to 1.5 is the maximum recommended in the CCM workbook).[3]
2) The NMED "margin of safety" effectively implies a retrofit factor of more than two. This represents an exceedingly difficult and highly unusual retrofit situation that would require extensive justification and documentation to be an acceptable claim (staff-to-staff communications with NPS and EPA OAQPS, July 18, 2024).
3) The NMED "margin of safety" is applied outside of the CCM cost calculations as opposed to integrating the cost of building and exhaust system modifications into the overall TCI and cost-effectiveness estimate. Again, significant justification is required for retrofit assumptions that exceed average difficulty.
4) The NMED's "margin of safety" was developed based on the assumed TCI associated with the CETV of $10,000/ton, not site-specific information identifying constraints that would suggest SCR installation may be particularly challenging in the given application.

Given this, the NPS finds that NMED's application of a general "margin of safety" is likely overstating the retrofit costs for SCR at individual sites and is not appropriate without the adequate site-specific justification. In many cases, determining if a retrofit factor is appropriate and identifying what that factor should be is not a simple process. The NPS recommends basing retrofit factors on site-specific considerations or constraints and applying them to the retrofit factor within the CCM cost calculation workbook. Higher-than-average retrofit cost assumptions (e.g., greater than 1.0) should include a thorough and well-documented analysis of the project-specific factors affecting retrofit difficulty. The procedure outlined by William Vatavuk on pages 59-62 in his book, *Estimating Costs of Air Pollution Control,* may be useful in these determinations. The Vatavuk process involves estimating and assigning a retrofit factor to each major element of a project and from that deriving an overall retrofit factor. In the absence of such a proper analysis, the NPS assumed a retrofit factor of 1.0 in all SCR analyses.

The NMED also dismissed SCR from consideration at several facilities due to space constraints. For example, at Enterprise Field Service's Blanco C and D Compressor Station, NMED did not include a cost assessment for SCR based on an aerial photograph. Materials in Appendix D note:

[3] From the CCM chapter for SCR: *The capital costs estimated by the equation represent average retrofit costs; costs for new construction are typically 20 to 30 percent less than for average retrofits for units of the same size and design. The TCI equations include a retrofit factor (RF). A retrofit factor of 0.8 should be used for new construction and a retrofit factor of 1 should be used for average retrofits. The equations may overestimate costs for some simple retrofits of existing plants. For retrofits that are more complicated than average, a retrofit factor of greater than 1 can be used to estimate capital costs provided the reasons for using a higher retrofit factor are appropriate and fully documented.*

> *An aerial map of the facility was provided in the 2020 follow up which suggests that new buildings (or substantial extensions of the existing building) would be required to house an SCR. The associated costs of building construction coupled with corresponding exhaust system modifications would be costly. Considering the calculated cost effectiveness of SCR for other CTs in New Mexico, it is reasonable to conclude that SCR is cost prohibitive for the Blanco C/D units.*

The NPS recommends providing a detailed, site-specific analysis, justification, and cost estimate to document and support the decision to exclude SCR from consideration. In the case of Blanco C and D Compressor Station, NMED and Enterprise did not address why the SCR would need to be housed *within* the building or the costs associated with building construction. The aerial photograph provided illustrates that the facility is located on a large gravel pad with ample additional space. As noted above, many of the retrofit costs, including exhaust system modifications, are incorporated into the CCM TCI calculations for retrofits. If excessive building costs are necessary, this should be documented and included in the cost estimates. Therefore, the NPS estimated the costs of SCR in several cases where it was excluded from the analysis due to space constraints (see Section 3).

Finally, with respect to operator costs, NMED included an additional cost of $87,600/year (4hours*365 days*$60/hour). It appears NMED used the workbook included with the CCM to estimate SCR retrofit costs, but included an additional annual operator cost to the workbook. The NMED based this cost on the CCM, which notes that EPA's Integrated Planning Model (which is the source of many of the costing equations) estimates operating labor time as 4 hours per day, which is the default value included in the workbook. (The CCM also notes operation of an SCR system requires only minimal operating or supervisory labor.) These costs are already included in the CCM SCR cost spreadsheet and are used with other data to estimate the administrative charges (see Data Inputs Tab, cells C58 and C59, which are used in the administrative charges calculation in cell D93 on the Cost Estimate Tab). The NPS recommends that NMED verify these assumptions and correct any errors in the annual operator cost assumptions. The NPS did not include this additional operator cost in its SCR cost estimates.

3 Facility-Specific Recommendations

3.1 Bloomfield Group Sources

Blanco Compressor Station A, San Juan Basin Gas Plant, & Blanco C&D Compressor Station

The Bloomfield group consists of three facilities, two natural gas compression stations and one natural gas processing plant located near Bloomfield, New Mexico, approximately 40 miles southeast of Mesa Verde National Park. The Bloomfield group includes Blanco Compressor Station A, owned and operated by El Paso Natural Gas (EPNG); the San Juan Basin Gas Plant, owned and operated by Hilcorp; and, Blanco C & D Compressor Station, owned by Enterprise and operated by Enterprise Products Operating, LLC. For the purposes of NSR, the Bloomfield group facilities are permitted as a single source.[4] Common control of the three facilities was established in 1984 through the issuance of a common NSR permit.[5] However, the plants continue to be permitted as three separate facilities for Title V purposes, under Title V Operating Permit numbers P048-R4, P124-R4 and P218-R3, respectively. Combined, these three facilities have the potential to emit over 3,700 tons/year of NO_x and are extremely important to address for haze impacts at Mesa Verde National Park, both cumulatively and individually.

The NPS appreciates that NMED included each of the three Bloomfield group facilities in the SIP four-factor analyses as requested by the NPS during New Mexico's source selection process. The NMED performed four-factor analyses for 24 individual units at the three facilities and is proposing some level of NO_x reduction for four of these units. The NPS appreciates and supports the need for additional NO_x reductions. However, the NPS recommends that greater NO_x reductions may be cost-effective and reasonable at the Bloomfield group units. The NPS recommends that NMED revise their cost analyses and reasonable progress determinations as described in Sections 3.1.1, 3.1.2, and 3.1.3 below. Addressing NO_x emissions at the three Bloomfield group facilities is important for the following reasons:

1) Along with ammonium sulfate, ammonium nitrate is one of the most important species contributing to visibility impairment at Mesa Verde National Park. Over the period of 2018–2022, ammonium nitrate was responsible for nearly 13% of impairment at Mesa Verde National Park on the 20% most impaired days.[6] In the winter months, ammonium

[4] San Juan Basin Gas Plant is owned and operated by ConocoPhillips Company and belongs to the Standard Industrial Classification (SIC) Major Group 13 (Oil & Gas Extraction)). Blanco A Compressor Station is owned and operated by El Paso Natural Gas Company and belongs to SIC Major Group 49. The Blanco C & D Compressor Station is owned by Enterprise Field Services, LLC and operated by Enterprise Products Operating, LLC and belongs to SIC Major Group 49.

[5] From the New Mexico statement of basis for a 2014 significant revision to the NSR permit: The NSR permit was issued jointly because Conoco (San Juan Gas Plant) had relied on reductions in boiler emissions from EPNG-Blanco to net out of the PSD Program. For Conoco to take credit for the emissions reduction at the EPNG-Blanco, common control of both plants had to be established. "Any separation of "THIS PLANT" into independent NSR permits would require an examination of PSD implications [EPA R6].

[6] See composition data, MEVE1 (2018-2022) available at: https://views.cira.colostate.edu/fed/Reports/Aqrv/BextComposition.aspx

nitrate is often the greatest contributor to haze at Mesa Verde National Park, comprising up to 40% of total impairment on individual most impaired days.[7]

2) Based on the WRAP WEP-AOI results, the Bloomfield group facilities are significant contributors to nitrate impairment at Mesa Verde National Park. The NPS sorted and ranked WRAP WEP-AOI data to evaluate the importance of individual facilities for Mesa Verde National Park[8] and found that:
    a) When considered individually, the Bloomfield group facilities are ranked among the top ten facilities contributing to nitrate impairment at Mesa Verde National Park. Individually, Blanco Compressor Station A is ranked number six, Blanco C & D Compressor Station is ranked number four, and San Juan Basin Gas Plant is ranked number five.[9]
    b) When considered cumulatively as a single facility (consistent with the NSR permit), the Bloomfield group is ranked the number two facility contributing to nitrate impairment at Mesa Verde National Park.[10]

For these reasons, the NPS requests that NMED reconsider the reasonable progress determinations for the Bloomfield group facilities in consideration of the NPS analyses provided below.

3.1.1 Blanco Compressor Station A

Blanco Compressor Station A (BCSA) is a natural gas compressor station located near Bloomfield, New Mexico, approximately 39.8 miles southeast of Mesa Verde National Park. The primary NO_x emission units at BCSA include 14 identical two-stroke lean-burn (2SLB) reciprocating internal combustion engines (RICE), each rated at 943 HP (units A01-A14). All 14 engines were manufactured by Cooper Bessemer and were installed in August of 1953.

The NMED evaluated the cost of installing Low Emission Combustion (LEC) controls at various levels as well as the cost of replacing each engine with a newer, low emission unit. The NMED identified cost-effective controls for units A11 and A13 and determined that engine replacement is necessary to make reasonable progress for these units.

The NPS appreciates NMED's well-documented analysis and agrees that engine replacement is likely the most stringent and cost-effective option for these aging emission units, which were installed over 70 years ago. However, the NPS recommends that NMED consider replacement costs based on facility-wide utilization rates rather than a unit-specific basis. This approach

[7] See the most impaired days, by sample day for MEVE1 (2022), available at: https://www.nps.gov/subjects/air/park-conditions-trends.htm?tabName=composition&parkCode=MEVE&paramCode=Visibility&startYr=2013&endYr=2022&monitoringSite=MEVE1%20(IMPROVE)&timePeriod=10-year

[8] See spreadsheet MEVE_POINT_RANK_NOX_NPS_WEPAOI.xlsx in NPS Attachment 2.

[9] This ranking removes the San Juan Generating Station (SJGS) from the overall rankings because it ceased operations in 2022 and is no longer a concern for Mesa Verde National Park. SJGS was previously ranked the number 2 impacting facility for this park.

[10] This ranking removes the San Juan Generating Station (SJGS)—see footnote 5.

indicates that replacing all 14 engines would be cost-effective. This approach is recommended the following reasons:

- There is significant annual variation in utilization rates for the individual engines (e.g., unit A01 ran nearly 7,000 hours in 2016 but zero hours in 2021), making it difficult to develop utilization and emission assumptions on a per-engine basis.
- NPS analysis demonstrates that the average facility-wide utilization is relatively consistent at approximately 25% annual utilization facility-wide (2016–2021 average). The recent maximum occurred in 2019 at 29% utilization. See Table 1.
- Likewise, estimated annual NO_x emissions for individual engines vary widely from year-to-year, but facility-wide emissions are relatively consistent, averaging approximately 200 tons/year.[11]

Table 1: Annual Operating Hours and Utilization Rates/Capacity Factors for BCSA (2016-2021)[12]

Unit No.	2016 Op. Hours	2017 Op. Hours	2018 Op. Hours	2019 Op. Hours	2020 Op. Hours	2021 Op. Hours	2016 Capacity Factor	2017 Capacity Factor	2018 Capacity Factor	2019 Capacity Factor	2020 Capacity Factor	2021 Capacity Factor
A01	6,728	5,123	579	3,787	2,500	0	0.77	0.58	0.07	0.43	0.29	0.00
A02	2	14	4	2,199	5,652	2	0.00	0.00	0.00	0.25	0.65	0.00
A03	5,012	5,953	3,182	5,182	225	108	0.57	0.68	0.36	0.59	0.03	0.01
A04	99	2	2	511	5,055	7,980	0.01	0.00	0.00	0.06	0.58	0.91
A05	281	5	9	3	0	1	0.03	0.00	0.00	0.00	0.00	0.00
A06	56	5,567	2,155	2	0	1	0.01	0.64	0.25	0.00	0.00	0.00
A07	5,964	6,666	1,371	3,691	2,547	1,946	0.68	0.76	0.16	0.42	0.29	0.22
A08	1	1	1	2	0	0	0.00	0.00	0.00	0.00	0.00	0.00
A09	2,499	183	866	3,141	2,144	5,007	0.29	0.02	0.10	0.36	0.24	0.57
A10	1	1	6	2	0	1	0.00	0.00	0.00	0.00	0.00	0.00
A11	4,404	3,239	7,450	6,581	7,642	7,076	0.50	0.37	0.85	0.75	0.87	0.81
A12	1	2	3,560	3	0	218	0.00	0.00	0.41	0.00	0.00	0.02
A13	7,490	6,827	6,108	7,130	998	1,033	0.86	0.78	0.70	0.81	0.11	0.12
A14	1	1	7,312	3,259	0	1	0.00	0.00	0.83	0.37	0.00	0.00
Facility-wide*	32,539	33,584	32,605	35,493	26,763	23,374	27%	27%	27%	29%	22%	19%

*Average Facility-wide Utilization 2016–2021 = 25% (See NPS workbook[13] in Attachment 2)

[11] NMED's assumed future actual emissions were developed using "representative" baseline utilization rates (2016-2021) for each engine. NMED notes that the SIP analysis conservatively adjusted reported emission factors to 100 percent load to represent worst-case emissions. The NPS assessment used NMED's adjusted emission factors but calculated representative emissions using the reported annual utilization rates for each unit (rather than representative emissions), summed emissions for each unit for each year to get the facility-wide annual emissions and then took the average of facility-wide emissions from 2016 to 2021. See NPS workbook "Blanco.Compressor.Station.A-NPS_CFs-emission _assumptions.xlsx" in Attachment A.

[12] Data Source: Appendix C: Four-Factor Analyses and Control Measures Determinations Technical Support Document, Section C.4.5.

[13] Blanco.Compressor.Station.A-NPS_CFs-emission _assumptions.xlsx

NPS Conclusions and Recommendations for Blanco Compressor Station A:

Given that the purpose of the facility is to provide natural gas compression, and that annual facility-wide utilization rates (i.e., compression needs) appear to be relatively consistent, the NPS recommends calculating replacement costs according to facility-wide utilization rather than on an individual engine basis. The NPS re-analyzed replacement costs for BCSA using:

1) NMED reported utilization rates,
2) NMED's cost metric of $3,227/hp (2020$) and
3) NMED reported emission factors.

This analysis found that replacing facility-wide compression needs is likely cost-effective. The results are summarized below (detailed calculations are provided in the NPS workbook[14] provided in Attachment 2):

- $7,320/ton (2023$) using the 2016–2021 average facility-wide utilization rate of 25% and average 2016–2021 emissions.
- $7,273/ton (2023$) using an assumed maximum facility-wide utilization rate of 30%. A capacity factor of 30% was selected to represent the maximum utilization year, 2019 at 29%, increased to 30% (or approximately 4,000 HP capacity). The facility-wide 2019 estimated emissions were used as the baseline emission rate in this scenario.
- NMED noted that their $3,227/hp metric is likely accurate to within ±30 percent.[15] The NPS facility-wide cost-effectiveness estimates are still below the NMED cost-effectiveness threshold of $10,000/ton when increased by 30%, at $9,516/ton (25% utilization) and $9,456/ton (30% utilization).

Finally, the NPS notes that the NMED online facility emissions report for Blanco Compressor station A, available through the air emission tool,[16] reports facility-wide 2019 NO_x emissions of 389 tons/year, which is higher than the estimates derived from the NMED emission factors and utilization rates reported for each of the 14 RICE in Appendix C to the SIP (i.e., 239 tons/year). It is not clear whether the emergency flare at the facility accounted for the additional 150 tons/year NO_x; however, the NO_x emission factors reported for several of the units seem inconsistent with the remaining units. This seems unusual given that the 14 units are identical size, vintage, make and model. For example, the NO_x emission factor reported for unit A04 is only 2.9 lb/hr, the NO_x emission factor reported for unit A03 is 8.4 lb/hr, and the NO_x emission factor reported for unit A02 is 9.1, whereas the emission factors reported for the remaining units

[14] Blanco.Compressor.Station.A-NPS_revisions_Replacement_Cost_Evaluation.xlsx
[15] From Appendix C: "EPNG provided a Total Capital Investment (TCI) cost metric of $3,227/hp (2020$) for the installation of new, replacement RICE at BCSA. The cost metric was developed by Kinder Morgan's Cost Estimating Group based on its extensive industry experience. NMED reviewed several publicly available resources along with information provided by other companies with similar units that could be used to estimate the TCI of a replacement RICE, and determined that the Kinder Morgan metric was reasonable. NMED understands that the use of this metric is likely accurate to within ±30 percent, but also recognizes that various preliminary vendor quotes are often caveated with a similar degree of accuracy."
[16] Available at: https://eatool.air.net.env.nm.gov/aqbeatool/facility-report?year=2019&sourceData=NMED&facilityId=1147

are 11.6 lb/hr (8 units), 12.1 lb/hr (1 unit) and 18.1 lb/hr (2 units) respectively. The NPS requests that NMED verify the reported emission factors, particularly for unit A04, and address the discrepancy between facility-wide emission estimates derived from the four-factor analysis assumptions and the NMED emission inventory.

3.1.2 San Juan Basin Gas Plant

The San Juan Basin Gas Plant (SJBGP) is a natural gas processing facility located near Bloomfield, New Mexico, approximately 39.6 miles southeast of Mesa Verde National Park. The facility consists of 7 NG-fired combustion turbines listed in Table 2.

Table 2: Description of SJBGP Units Selected for Four-Factor Analysis

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
1	Turbine	Rolls Royce Avon 1535	1985/1986 (1)	15,000 hp
2	Turbine	Rolls Royce Avon 1535	1985/1986 (1)	15,000 hp
3	Turbine	Rolls Royce Avon 1535	1985/1986 (1)	15,000 hp
4	Turbine	Solar Centaur T4501	1986	3,735 hp
5	Turbine	Solar Centaur T4501	1986	3,735 hp
6	Turbine	Solar Centaur T4501	1986	3,735 hp
7	Turbine	Solar Centaur T4501	1986	3,735 hp

The NMED determined that dry low-NO_x (DLN) represents reasonable progress for units 4, 5, 6, and 7. The NMED rejected SCR due to an "inadequate margin of safety" for all seven units, even though SCR costs were at or below NMED's CETV of $10,000/ton for each of the turbines.

NPS Conclusions and Recommendations for SJBGP

The NPS estimates that applying SCR to all seven turbines could reduce 437 tons/year of NO_x emissions versus the 159 tons/year reduction achieved under NMED's proposal to install DLN on turbines 4–7. The NPS recommends that NMED reconsider their control determinations and require SCR for the seven combustion turbines at SJBGP, which is cost-effective relative to NMED's CETV of $10,000/ton.

As discussed in Section 2.6, NMED's "margin of safety" effectively assumes a retrofit factor of two, which represents an difficult and unusual retrofit situation that would require extensive justification and documentation. As such, the NPS finds that NMED's "margin of safety" is likely overstating the retrofit costs for SCR at individual sites.

The NMED summarized its cost-effectiveness estimates for SCR in Appendix C to the SIP but deleted them from the SCR spreadsheet calculations for SJBGP. Because of this, the NPS re-ran the SCR cost analyses to verify NMED's estimates for SJBGP. The NPS generally used NMED's analysis assumptions, including representative operating hours and emissions, cost year, and interest with the following exceptions:

- The NPS used a higher ammonia reagent cost that is reflective of 2023 commodity values ($0.529/gal).

- The NPS used a higher catalyst replacement cost ($9,000/m^3) that is reflective of more recent commodity values based on a 2022 Sargent and Lundy update to the SCR cost calculations prepared in support of EPA's Good Neighbor proposal.
- The NPS used the Chemical Engineering Plant Cost Index (CEPCI) (797.9) to escalate to 2023$ which is slightly higher than the Consumer Price Index (CPI) method used by NMED.
- The NPS assumed a 25-year equipment life. The CCM notes that the equipment lifetime of an SCR system is typically assumed to be 20 to 25 years for industrial boilers. The NPS uses the higher end of this range for combustion turbines firing natural gas, as it is anticipated the equipment life would be longer than for industrial boilers firing coal or oil.

Despite these differences, NPS estimates are similar to NMED's cost estimates for SCR and are below NMED's $10,000/ton CETV for turbines 1–7:

Table 3: Summary of NPS SCR Cost-effectiveness Values for SJBGP vs. NMED SCR and DLN Cost-effectiveness Values

SJBGP Unit No.	Baseline Actual NO_x Emissions (ton/yr)	NMED Proposed Reduction (ton/yr)	NPS Estimated Reductions SCR (ton/yr)	NPS Estimated Cost Effectiveness SCR 2023$ ($/ton)	NMED Estimated Cost Effectiveness SCR 2023$ ($/ton)	NMED Estimated Cost Effectiveness DLN 2023$ ($/ton)
1	83	0	75	$9,691	$10,000	$365,000
2	90	0	81	$9,117	$9,000	$247,000
3	83	0	75	$9,488	$10,000	-$5,195,000 (1)
4	56	38	50	$5,791	$7,000	$10,000
5	55	38	50	$5,839	$7,000	$10,000
6	61	43	55	$5,309	$6,000	$8,000
7	57	40	51	$5,680	$7,000	$9,000
Total	485	159	437			

In addition, both the NPS and NMED SCR cost-effectiveness values are lower than NMED's DLN estimates. The NPS encourages NMED to reconsider the reasonable progress determination for SJBGP and require SCR for turbines 1 through 7.

3.1.3 Blanco C&D Compressor Station

Blanco Compressor Station C & D (BCSCD) is a natural gas compressor station located near Bloomfield, New Mexico, approximately 40 miles southeast of Mesa Verde National Park. The facility includes three natural gas-fired combustion turbines selected for analysis (Table 4).

Table 4: Description of BCSCD Units Selected for Four-Factor Analysis

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
T-C01	Turbine	General Electric 5221W	<June 1989	22,280 hp
T-C02	Turbine	General Electric 5221W	<June 1989	22,280 hp
T-D01	Turbine	General Electric M5322B	<October 1987	32,550 hp

The NMED's four-factor analysis did not identify any cost-effective controls for BCDCS Units T-C01, T-C02, and T-D01and determined that reasonable progress does not require new controls on any of these units. The NMED completely dismissed SCR from consideration at BCSCD due to concerns over "space constraints."

NPS Conclusions and Recommendations for BCSCD

The NPS recommends that NMED reconsider their control determinations and require SCR for units T-C01 and T-C02 and consider SCR for unit T-D01 at BCSCE, as described below. In their review of the four-factor analysis submittal, NMED accepted Enterprise Field Service's demonstration that there is insufficient space to accommodate an SCR. Enterprise Field Service's demonstration consists of an aerial photograph of the site, with rough overlays of "SCR dimensions" and identified the assumed "area available for SCR" (see Figure 1). The materials provided in Appendix D to the SIP (NMED workbook *2024-05-20_NMED's Draft Cost Evaluation for Blanco C&D Compressor Station [External Review Copy].xlsx*, *SCR* tab) note:

> *Enterprise indicated in its initial 2019 FFA submittal, 2020 follow-up and 2023 update that there is insufficient space to accommodate SCR. In support of its assertion, it indicated (2020 follow up) that CECO-Peerless stated that "an area of approximately 40' x 20' is required for an SCR unit" and a copy of the correspondence was provided. An aerial map of the facility was provided in the 2020 follow up which suggests that new buildings (or substantial extensions of the existing building) would be required to house an SCR. The associated costs of building construction coupled with corresponding exhaust system modifications would be costly. Considering the calculated cost effectiveness of SCR for other CTs in New Mexico, it is reasonable to conclude that SCR is cost prohibitive for the Blanco C/D units.*

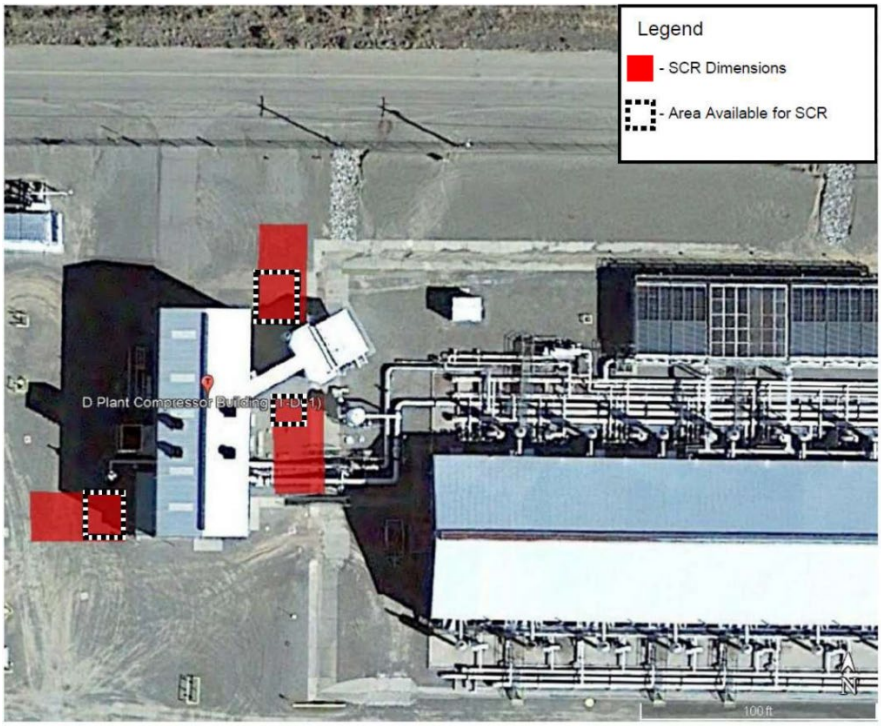


Figure 1: Aerial View of Blanco Compressor Station C & D

As discussed in Section 2.6, NMED and Enterprise did not address why the SCR would need to be housed within the building or the costs associated with building construction. The aerial photograph provided illustrates that the facility is located on a large gravel pad with ample additional space. As noted in Section 2.5, many of the retrofit costs, including exhaust system modifications, are incorporated into the CCM TCI calculations for retrofits. If excessive building costs are necessary, this should be well documented and included in the overall cost estimates. Given the lack of documentation regarding specific space constraints and building costs, the NPS estimated the costs of SCR for the three turbines located at BCSCD.

Based on NPS estimates, installation of SCR on all three turbines could reduce 420 tons/year of NO_x emissions. The NPS recommends that NMED reconsider their control determinations and require SCR for units T-C01 and T-C02 and consider SCR for unit T-D01 at BCSCE. The NPS estimates demonstrate that SCR controls for turbines T-C01 and T-C02 are very cost-effective relative to NMED's CETV of $10,000/ton at $7,458/ton and $5,411/ton, respectively. Costs for unit T-D01 were slightly above NMED's CETV of $10,000/ton, but still below the $14,000/ton breakpoint identified in NMED's revised CETV analysis. As discussed in Section 2.5, the NPS recommends that NMED consider additional controls that are estimated to be right at or just above the New Mexico $10,000/ton CETV. This recommendation is consistent with the NMED finding that incremental NO_x reductions are consistent (and may be cost-effective) up to $14,000/ton. It is also consistent with EPA guidance which recommends that control costs are typically estimated at an accuracy level of plus or minus 30%.

Table 5: Summary of NPS SCR Cost-effectiveness Values for BCSCD

Blanco C & D Unit No.	Baseline Actual NO_x Emissions (ton/yr)	NMED Proposed Reduction (ton/yr)	NPS Estimated Reductions SCR (ton/yr)	NPS Estimated Cost Effectiveness SCR 2023$ ($/ton)
T-C01	140	0	126	$7,458
T-C02	195	0	176	$5,411
T-D01	132	0	118	$11,398
Total	466	0	420	

3.2 Linam Ranch Gas Plant

Linam Ranch Gas Plant is a natural gas processing facility located 7 miles west of Hobbs in Lea County, New Mexico. The shortest distance to the boundary of the nearest Class I Area, Carlsbad Caverns National Park, is approximately 72.7 miles. The facility has a total potential to emit of 973.5 tons per year of NO_x and 87.1 tons per year of SO_2. The SIP reports baseline emissions of 272 tons NO_x/year.

The Linam Ranch plant includes six two-stroke lean-burn (2SLB) RICE engines, two of which are no longer operational (Units 8 and 9), and four turbines.

Table 6. Linam Ranch emissions units.

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
6	2SLB RICE	Clark TLA-6	1974 or before	2,000 hp
7	2SLB RICE	Clark TLA-6	1974 or before	2,000 hp
8	2SLB RICE	Clark HBA-6	1951	1,267 hp
9	2SLB RICE	Clark HBA-6	1951	1,267 hp
10	2SLB RICE	Clark HBA-6	1951	1,267 hp
11	2SLB RICE	Clark HBA-6	1951	1,267 hp
29	Turbine	Solar Taurus T-70	1995	10,702 hp
30	Turbine	Solar Taurus T-70	1995	9,900 hp
31	Turbine	Solar Centaur T-4700	1995	4,700 hp
32B	Turbine	Solar Centaur T-4000	1979	3,961 hp

The four-factor analysis in the SIP evaluated potential options for reducing NO_x emissions from the engines. The NMED concluded that SCR, SNCR, and NSCR are not technically feasible options for the two-stroke engines at Linam Ranch, but LEC retrofit and unit replacement are feasible options. The resulting cost-effectiveness estimates were all above the $10,000/ton cost threshold, and NMED determined that new controls are not required on these engines to meet reasonable progress goals.

The SIP four-factor analysis also evaluated NO_x reduction options for the four turbines at Linam Ranch. The NMED considered retrofitting the turbines with dry low-NO_x (DLN) technology and adding SCR as a post-combustion control. The facility operator has already upgraded Units 29,

30, and 31 with DLN to comply with the state's ozone precursor rule. The NMED's cost effectiveness estimates for DLN and SCR on turbine 32B were below its cost threshold of $10,000/ton, at $9,217/ton NO_x removed for DLN and $7,774/ton for SCR. Despite the lower cost effectiveness estimate, SCR was rejected due to an inadequate "margin of safety." As discussed in detail in Section 2.6, the NPS disagrees with applying a default "margin of safety" to SCR cost-effectiveness estimates. The NMED determined that DLN is cost-effective for Unit 32B and necessary to make reasonable progress.

The NPS used the CCM SCR calculation workbook to complete its cost-effectiveness estimate for SCR, documented in a workbook[17] included in Attachment 2. The NPS workbook includes some differences from NMED's approach. As discussed in Section 2.6, NMED added an extra operator cost that is not included in the NPS estimate. In addition, NPS used an expected lifetime of 25 years rather than 20 years as NMED used in its analysis. The SCR workbook notes that for industrial boilers, the typical equipment life is between 20 and 25 years. The longer lifetime is appropriate for a gas-fired turbine. Finally, the NPS used the CEPCI index to adjust costs to 2023$ rather than the CPI. This resulted in a cost-effectiveness estimate for SCR on turbine 32B of $7,098/ton NO_x removed. While the difference in NO_x emissions removed between SCR and DLN is not large, the cost analysis suggests that SCR may be more cost-effective to reduce NO_x emissions from this turbine.

3.3 Kutz Canyon Processing Plant

Kutz Canyon is a natural gas processing facility located approximately 43.2 miles from the nearest Class I area, Mesa Verde National Park. The SIP evaluated eight Solar Centaur turbines at the facility for potential NO_x emissions reductions; three four-stroke rich-burn RICE engines originally identified for four-factor analysis have shut down. Baseline NO_x emissions for the turbines are shown in the following table.

Table 7. Kutz Canyon turbine baseline emissions.

Unit No.	Adjusted Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual Emissions (ton/yr)
1	16.7	6940	58.0
2	17.7	5375	47.5
3	12.6	5175	32.5
4	14.1	6257 (1)	46.1
5	11.9	6924	41.2
6	11.8	8224	48.4
19	15.6	4812	37.6
20	15.6	3884	30.3

(1) Unit 4 has not operated since 2018, skewing its 2016-21 average operating hours. Therefore, the average 2016-21 average operating hours of identical Units 1, 2, 3, 5, and 6 were used as a surrogate for Unit 4.

[17] Linam_Ranch_A02_32B.xlsm

The four-factor analysis evaluated both DLN and SCR to reduce NO_x emissions from the eight turbines. The NMED's cost-effectiveness estimates for DLN were below the threshold of $10,000/ton for units 1–6 and 19. The SCR retrofit cost estimates were also below NMED's threshold for Units 1, 2, 4, 5, 6, and 19. The NMED rejected SCR for units 1, 2, 6, and 19 due to insufficient "margin of safety" and determined that DLN is required for Units 1–5 and 19. As discussed in detail in Section 2.6, the NPS disagrees with applying a default "margin of safety" to SCR cost-effectiveness estimates. The four-factor analysis estimates that application of DLN to these six engines will reduce the facility's NO_x emissions by 172.8 tons/year.

The NPS used the CCM SCR calculation workbook to estimate costs for retrofitting the turbines with SCR, documented in workbooks[18] included in Attachment 2. The NPS workbooks include some differences from NMED's approach. As discussed in Section 2.6, NMED added an extra operator cost that is not included in the NPS estimates. In addition, NPS used an expected lifetime of 25 years rather than 20 years as NMED used in its analysis. The SCR workbook notes that for industrial boilers, the typical equipment life is between 20 and 25 years. The longer lifetime is appropriate for a gas-fired turbine. Finally, the NPS used the CEPCI index to adjust costs to 2023$ rather than the CPI. The resulting NPS estimates are shown in the following table.

Table 8. NPS SCR cost-effectiveness estimates.

Unit	NO_x tons removed	Cost effectiveness ($/ton)
1	52	$5,243
2	43	$6,284
3	29	$9,179
4	42	$6,481
5	37	$7,370
6	44	$6,275
19	34	$6,782
20	27	$8,329

The NPS cost-effectiveness estimates suggest that SCR is cost-effective for all eight turbines, which could reduce NO_x emissions by 280.2 tons/year. The NPS recommends that NMED consider requiring SCR for all eight turbines, as this would reduce NO_x by an additional 108 tons/year compared to the application of DLN to six of the eight turbines.

3.4 Chaco Gas Plant

The Chaco plant is a natural gas processing facility approximately 49.8 miles from the boundary of the nearest Class I area, Mesa Verde National Park. The NMED selected eight emissions units

[18] *Kutz_A01_SCR.xlsm* through *Kutz_A20_SCR.xlsm*

for evaluation, including three two-stroke RICE engines and five turbines. Baseline emissions for these units are shown in Table 9.

Table 9. Chaco Gas Plant baseline emissions.

Unit	Description	Make & Model	Permitted Capacity	Baseline NO_x Emissions (ton/yr)
12	2SLB RICE	Clark TLA-10	3,400 hp	88.7
13	2SLB RICE	Clark TLA-10	3,400 hp	41.8
14	2SLB RICE	Clark TLA-10	3,400 hp	131.2
17	Turbine	General Electric Frame 5	19,500 hp	75.3
18	Turbine	General Electric Frame 5	19,500 hp	80.9
35	Turbine	Solar Mars T-15000	15,000 hp	98.0
36	Turbine	Solar Mars T-15000	15,000 hp	92.5
37	Turbine	Solar Mars T-15000	15,000 hp	82.2

The four-factor analysis states that the three RICE engines are already equipped with LEC, but that it is feasible to upgrade these engines to meet a 0.5 g/hp-hr NO_x emissions rate. The NMED concluded that only Unit 14 is cost-effective to upgrade and is requiring it only for this unit.

The NMED did not consider SCR to be a technically feasible option to reduce NO_x emissions from the turbines due to a lack of space. This conclusion was based upon an aerial image with measurement overlays. As discussed in more detail in Section 2.6, the analysis should include a detailed, site-specific analysis, justification, and cost estimate to support the decision to exclude SCR from consideration. In the absence of this justification, the NPS recommends NMED analyze the cost-effectiveness of retrofitting the turbines with SCR.

3.5 South Carlsbad Compressor Station

The South Carlsbad Compressor Station is located 2.8 miles northwest of Loving in Eddy County, New Mexico and approximately 16.2 miles from the nearest Class I area, Carlsbad Caverns National Park. The NMED evaluated potential NO_x controls for two gas-powered Solar Centaur T-4702 4,328 hp turbine engines. Emissions for these units are shown in Table 10.

Table 10. South Carlsbad baseline emissions.

Unit No.	Adjusted NO_x Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_x Emissions (ton/yr)
1	18.1	8524	77.2
2	18.2	8467	76.9

The NMED evaluated DLN for NO_x control and found it to be cost-effective at $4,000/ton. The NMED determined DLN is necessary for both turbines to make reasonable progress. Anticipated NO_x reductions are shown in the following table.

Table 11. Expected NO_x emissions reductions at South Carlsbad.

Unit No.	Control Measure	Estimated NO_X Reductions (ton/yr)
1	DLN	61.9
2	DLN	61.5

The NMED also determined that SCR is technically feasible for these turbines but dismissed it from consideration due to a lack of space. The NPS suggests SCR could achieve a NO_x reduction efficiency of 90%, vs an expected 80% reduction for DLN. The operator asserted there is insufficient space to accommodate SCR and provided an aerial image with measurement overlays of buildings to house the units. As discussed in more detail in Section 2.6, the analysis should include a detailed, site-specific analysis, justification, and cost estimate to support the decision to exclude SCR from consideration. In the absence of this justification, the NPS recommends NMED analyze the cost-effectiveness of retrofitting the turbines with SCR and select the cost-effective control that achieves the greatest reduction in emissions.

3.6 Washington Ranch Storage Facility

The Washington Ranch Storage Facility is a natural gas storage facility located 9.1 miles southwest of Whites City in Eddy County, New Mexico. The nearest Class I area is Carlsbad Caverns National Park, which is approximately 3.4 miles away. The facility's total potential to emit is 243.6 tons per year of NO_x and 4.8 tons per year of SO_2.

The four-factor analysis evaluated NO_x control options for two two-stroke RICE engines. Average operating hours and baseline emissions for these units are shown in the following table.

Table 12. Washington Ranch baseline emissions.

Unit No.	Adjusted NO_X Emissions (lb/hr @ 100% load)	Representative Annual Operating Hours (hr/yr)	Baseline Actual NO_X Emissions (ton/yr)
1	7.3	2675	9.7
2	4.2	2607	5.5

Both units already have LEC installed, resulting in controlled NO_x emission rates of 0.5 and 0.8 g/hp-hr, respectively. The NMED determined that engine replacement is technically feasible and would achieve a NO_x emissions rate of 0.3 g/hp-hr but concluded that this option is not cost-effective. Given the relatively low baseline emissions and potential for emissions reduction, the NPS agrees that replacement costs would likely exceed the $10,000/ton threshold. The NPS supports NMED's determination that continued use of the existing controls on these units is necessary for reasonable progress.

3.7 Indian Basin Gas Plant

The Indian Basin Gas Plant (IBGP) is a natural gas processing facility located near the city of Carlsbad in Eddy County, New Mexico, approximately 21.2 miles north of Carlsbad Caverns National Park. The facility is owned and operated by Oxy and currently operates under Title V

Operating Permit No. P103-R3. The facility units selected for four-factor analysis include three NG-fired combustion turbines:

Table 13: Description of IBGP Units Selected for Four-Factor Analysis

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
ES-06/07	Turbine	Solar Centaur 40	1980	4,000 hp
ES-08/09	Turbine	Solar Centaur 40	1980	4,000 hp
ES-10/11	Turbine	Solar Centaur 40	1980	4,700 hp

The NMED evaluated DLN, SCR, and replacement for the three turbines located at IBGP. The NMED determined that DLN represents reasonable progress for each of the three units. The NMED did not select SCR due to estimated cost effectiveness that was over the identified CETV.

NPS Conclusions and Recommendations for IBGP

The NPS supports NMED's decision to implement controls at IBGP. The NPS cost estimates for SCR were much lower than NMED's estimates and were below NMED's $10,000/ton CETV for all three turbines at IBGP. The NPS cost-effectiveness estimates for SCR were also below NMED's estimates for DLN. However, there is minimal difference in the potential NO_x emission reductions between NMED's proposal to require DLN versus the NPS estimated reductions with SCR. Given this, the NPS supports implementation of either DLN or SCR for these units. However, if utilization were to increase in the future, SCR may be a better option to maintain NO_x emission reductions.

A summary of NPS analysis results is provided in Table 14. The NPS generally used NMED's analysis assumptions, including representative operating hours and emissions, cost year, and interest rates with the following exceptions:

- The NPS used a higher ammonia reagent cost that is reflective of 2023 commodity values ($0.529/gal).
- The NPS assumed a 25-year equipment life. The CCM notes that the equipment lifetime of an SCR system is typically assumed to be 20 to 25 years for industrial boilers. The NPS uses the higher end of this range for combustion turbines firing natural gas, as it is anticipated the equipment life would be longer than for industrial boilers firing coal or oil.
- The NPS used the CEPCI cost index to escalate to 2023$ which is slightly higher than the CPI used by NMED.

Table 14. Summary of NPS SCR Cost-effectiveness Values for IBGP vs. NMED SCR and DLN Cost-effectiveness Values

IBGP Unit No.	Baseline Actual NO_x Emissions (ton/yr)	NMED Proposed Reduction (ton/yr)	NPS Estimated Reductions SCR (ton/yr)	NMED Proposed NO_x Reductions DLN (ton/yr)	NPS Estimated Cost Effectiveness SCR 2023$ ($/ton)	NMED Estimated Cost Effectiveness DLN 2023$ ($/ton)	NMED Estimated Cost Effectiveness SCR 2023$ ($/ton)
ES-06/07	49	0	44	37	$6,714	$8,000	$12,000
ES-08/09	47	0	43	35	$7,486	$8,000	$12,000
ES-10/11	43	0	39	29	$8,845	$9,000	$14,000
Total	140	0	126	101			

Not only is the average cost-effectiveness of adding SCR to each of the combustion turbines reasonable, the incremental cost-effectiveness of SCR relative to DLN is also very reasonable, shown in Table 15.

Table 15. Summary of NPS SCR Incremental Cost-effectiveness Values for IBGP vs. NMED SCR and DLN Cost-effectiveness Values

IBGP Unit No.	NPS TAC for SCR	NMED TAC for DLN	Incremental Costs	Removed SCR	Removed DLN	Incremental Removal	Incremental Cost-Effectiveness ($/ton)
	($/yr)			(tons/yr)			
ES-06/07	$295,416	$296,000	($584)	44	37	7	$ (83)
ES-08/09	$321,898	$280,000	$41,898	43	35	8	$ 5,237
ES-10/11	$344,955	$261,000	$83,955	39	29	10	$ 8,396

The NPS recommends considering addition of SCR to each of these three combustion turbines to reduce NO_X emissions by about 126 tons/year.

3.8 Artesia Gas Plant

Artesia Gas Plant (AGP) is a natural gas processing facility located near Artesia in Eddy County, New Mexico, approximately 39.8 miles from Carlsbad Caverns National Park. The NMED evaluated the amine treatment system (ATS) at AGP for potential SO_2 control measures but did not evaluate NO_x emissions for the facility. Based on the permit documents and national emission inventory information, it appears this facility has 17 RICE, (five 4SLB and twelve 4SRB) [19] and two natural gas-fired boilers.[20] Facility-wide potential to emit is 476 tons/year of

[19] These include units 10-17, units 25-27, units 30-34 and unit 39.
[20] These include units 20 & 28.

NO_x and reported actual emissions for 2019 were 181 tons/year NO_x.[21] The NMED did not address NO_x emissions associated with this facility in the four-factor analysis and did not include justification in SIP document materials. The NPS has two clarifying questions with respect to this facility:

1. Why did NMED screen NO_x emissions from four-factor analysis? Were the individual RICE and boiler unit emissions below NMED's screening criteria for individual units (i.e., PTE less than 10 tons/year)? The NPS notes that, based on the permit information, it appears the potential to emit falls below NMED's screening criteria. Please clarify this in the SIP.
2. Are the larger engines subject to NMED's Oil and Gas Sector – Ozone Precursor Pollutants Rule (NMAC 20.2.50.1)? If so, the NPS recommends summarizing any anticipated NO_x reductions in the SIP.

3.9 Cunningham Station Power Plant

Cunningham Station Power Plant (CSPP) is a 487 MW electric power plant owned and operated by Southwestern Public Service Company, a subsidiary of Xcel Energy. The CSPP is located 69.4 miles northeast of Carlsbad Caverns National Park.

Table 16. CSPP Emission Units

Unit No.	Description	Make & Model	Date of Manufacture	Permitted Capacity
1	Boiler	Combustion Engineering 9752	< 1957	82 MW
2	Boiler	Combustion Engineering 19813	< 1957	234 MW
3	Turbine	Westinghouse 501D5	< 1957	115 MW
4	Turbine	Westinghouse 501D5	< 1957	115 MW

3.9.1 NMED Determinations

- NMED determined that:
  - SCR is cost-effective for units 1 & 2.
  - No additional controls are cost-effective for units 3 & 4.
- Unit 1 appears to be shut down already based on EPA Clean Air Markets Program data. Xcel is seeking approval to extend the service life of Unit 2 to 2027 and retire it in 2027, which would preclude the installation of new controls.

3.9.2 NPS Conclusions and Recommendations

The NPS agrees with NMED's control determinations. In addition, the NPS recommends that CSPP be required to install and operate SCR on units 1 and/or 2 no later than January 1, 2031, if either unit operates beyond the December 31, 2027 end of the second planning period.

[21] See NMEDs facility emission report, available at: https://eatool.air.net.env.nm.gov/aqbeatool/facility-report?year=2019&sourceData=NMED&facilityId=199

3.10 NPS Support for NMED Reasonable Progress Determinations

The NPS generally supports the following NMED reasonable progress determinations and encourages the agency to move forward with these decisions in the final regional haze SIP:

- PECOS RIVER COMPRESSOR STATION (PRCS): Located approximately 22.1 miles from Carlsbad Caverns National Park, PRCS has a potential to emit of 697.7 tons/year of NO_x and 5.6 tons per year of SO_2. The NMED performed a four-factor analysis for three turbines located at the facility (units A-01, A-02 and A-03). The NMED determined that SCR is cost-effective and necessary to make reasonable progress on units A-02 and A-03. The cost of SCR was above NMED's CETV for unit A-01 at $12,000/ton.
    - NPS SCR estimates are lower (likely for the reasons discussed in Section 2.5) and find that SCR would also be cost-effective and reasonable for unit A-01 at PRCS.[22]
- MOUNTAINAIR COMPRESSOR STATION (MACS) NO. 7: Located approximately 50 miles from Bosque del Apache Wilderness Area (WA), MACS has a potential to emit of 2,264 tons/year of NO_x. The NMED performed a four-factor analysis for three 4SLB RICE and two 4SRB RICE at MCS. The NMED determined that engine replacement is cost-effective and necessary to make reasonable progress for all five engines evaluated. The NPS is supportive of these determinations that will reduce 1,285 tons/year of NO_x emissions and agrees these measures are necessary to make reasonable progress.
- ROSWELL COMPRESSOR STATION (RCS) NO. 9: Located approximately 5.6 miles from Salt Creek WA, RCS has a potential to emit of 1,123 tons per year of NO_x and 0.8 tons per year of SO_2. The NMED performed a four-factor analysis for two 4SLB RICE at RCS. The NMED determined that replacement of both engines is cost-effective and necessary to make reasonable progress. The NPS is supportive of these determinations that will reduce 645 tons/year of NO_x emissions and agrees these measures are necessary to make reasonable progress.
- EUNICE GAS PROCESSING PLANT (EGPP): Located approximately 73.5 miles from Carlsbad Caverns National Park, EGPP has a potential to emit of 2,606 tons per year of NO_x and 482 tons per year of SO_2. The NMED performed a four-factor analysis for all technically feasible control options for two industrial boilers and seven 2SLB RICE at EGPP. The NMED determined that installation of Low NO_x Burners (LNB) on both boilers (B01 & B02) and replacement of all seven engines (C-01 through C-07) is cost-effective and necessary to make reasonable progress. The NPS is supportive of these determinations that will reduce 1,288 tons/year of NO_x emissions and agrees these measures are necessary to make reasonable progress.
- MONUMENT GAS PLANT (MGP): Located approximately 68.2 miles from Carlsbad Caverns National Park, MGP has a potential to emit of 1,013 tons/year of NO_x and 373 tons/year of SO2. The NMED performed a four-factor analysis for seven 2SLB RICE at MGP. The NMED determined that replacement of five engines is cost-effective and necessary to make reasonable progress (units C-01, C-02, C-05, C-06 & C-24). The NMED did not identify cost-effective controls for units C-04 and C-28. The NPS is

[22] See Spreadsheet in Attachment 2 *Pecos_river_SCR_CCM_spreadsheet_test_A03.xlsm*

supportive of these determinations that will reduce 409 tons/year of NO_x emissions and agrees these measures are necessary to make reasonable progress.

- The NPS notes that the utilization rates on units C-04 and C-28 are relatively inconsistent from year to year. Like the NPS recommendations for Blanco Compressor Station A, NMED may consider also looking at replacement costs on a facility-wide basis.

The NPS appreciates the thorough NMED review of sources and the proposed reductions that could be achieved at these sources. The NPS encourages NMED to move forward with additional recommended measures to reduce haze causing emissions. As NMED observes in the SIP *substantial reductions in emissions of NO_X and SO_2 will translate into visibility benefits*. These types of reduction measures (from many smaller sources) are particularly necessary in states like New Mexico, where numerous "small" oil and gas sources comprise a significant fraction of the statewide emissions inventory. Large emission sources are generally more cost-effective to control and often result in measurable improvement from individual facility reductions. Once these large emission sources are well-controlled, ongoing progress will require reductions from numerous smaller sources, where improvement may only be measurable in the aggregate. The NPS appreciates that NMED recognizes this fact in its CETV and overall approach to regional haze planning.

3.11 Oil and Gas Non-point Sources

In August 2022, NMED finalized the Ozone Precursor Pollutants Rule to address emissions from oil and gas sources located in areas that are with 95% of the ozone National Ambient Air Quality Standard (NAAQS).[23] The NPS applauds NMED's efforts to address the substantial emissions from the oil and gas source sector in New Mexico. This source sector contributes to both increased ozone levels and visibility impairment in New Mexico Class I areas. According to Table 5-11 in the SIP, oil and gas point sources emitted 31,244 tons/year of NO_x and oil and gas non-point sources emitted 50,064 tons/year of NO_x during the 2014–2018 timeframe. The NO_x reductions that will be achieved under NMED's Ozone Precursor Pollutant Rule are essential to addressing the significant air quality concerns in and near large oil and gas development basins in New Mexico and will help further reasonable progress in Class I areas.

The NPS has been supportive of these type of state rulemaking efforts. Consistent with NPS input provided during the NMED rulemaking hearing in September 2021 (EIB No. 21-27 (R))[24], the NPS continues to recommend that New Mexico implement additional rule requirements and further reduce NO_x emissions by (1) addressing smaller engine size classes and (2) requiring lower NO_x limits for various engine size classes/configurations.

[23] The final rule is codified in 20.2.50 NMAC Oil and Gas Sector – Ozone Precursor Pollutants, available at: https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2022/07/Oil-and-Gas-Sector-Ozone-Precursor-Polutants-Final-rule-20.2.50-NMAC-06Jul22.pdf

[24] See Appendix 2: *NPS comments oil and gas rule Exhibit B.pdf*

The earlier NPS recommendations were based on rules implemented in other states, including Texas, Pennsylvania, and California. Since the NMED rulemaking, the Colorado Department of Public Health and Environment (CDPHE) issued final oil and gas rules to reduce NO_x emissions from engines statewide. The CDPHE rules address stationary engines 500 HP or larger, as well as pre-production drilling and completion activities located in the Colorado front range nonattainment area.[25] The NPS is including the final Colorado rules adopted by the state's Air Quality Control Commission in December 2023 for reference in Attachment 2 (note: these rule versions are the redline strike out versions issued by Colorado to highlight the final adopted rule changes). The NPS now recommends NMED also consider the CDPHE model for reducing ozone emissions from oil and gas area sources.

[25] See Colorado REGULATION NUMBER 26 Control of Emissions from Engines and Major Stationary Sources 5 CCR 1001-30 and REGULATION NUMBER 7 Control of Emissions from Oil and Gas Emissions Operations 5 CCR 1001-9.

Appendix G: Proposed Rule 20.2.68 NMAC - Regional Haze Requirements

TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 68 REGIONAL HAZE REQUIREMENTS

20.2.68.1 ISSUING AGENCY: Environmental improvement board.
[20.2.68.1 NMAC – N, 07/01/2025]

20.2.68.2 SCOPE: All geographic areas within the jurisdiction of the environmental improvement board.
[20.2.68.2 NMAC – N, 07/01/2025]

20.2.68.3 STATUTORY AUTHORITY: Environmental Improvement Act, Sections 74-1-1 to 74-1-18 NMSA 1978, including specifically Paragraph (4) of Subsection A of Section 74-1-8 NMSA 1978, and Air Quality Control Act, Sections 74-2-1 to 74-2-17 NMSA 1978, including specifically Paragraph (1) of Subsection D of Section 74-2-5 NMSA 1978.
[20.2.68.3 NMAC – N, 07/01/2025]

20.2.68.4 DURATION: Permanent.
[20.2.68.4 NMAC – N, 07/01/2025]

20.2.68.5 EFFECTIVE DATE: July 1, 2025, except where a later date is cited at the end of a section.
[20.2.68.5 NMAC – N, 07/01/2025]

20.2.68.6 OBJECTIVE: The objective of this Part is to establish enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress during the second regional haze implementation period, and provisions to make these measures practicably enforceable, including averaging times, monitoring requirements, and recordkeeping and reporting requirements.
[20.2.68.6 NMAC – N, 07/01/2025]

20.2.68.7 DEFINITIONS: In addition to the terms defined in 20.2.2 NMAC – Definitions, as used in this Part, the following definitions apply:

A. "Agency interest number" or "AI #" means the unique identification number assigned to every facility that is regulated by the department.

B. "Calendar year" means a year beginning January 1 and ending December 31.

C. "CFR" means the Code of Federal Regulations.

D. "Continuous emission monitoring system" or "CEMS" means all of the equipment required to sample, condition (if applicable), analyze, and provide a record of emissions on a continuous basis.

E. "Environmental protection agency" or "EPA" means the United States environmental protection agency.

F. "g/bhp-hr" means grams per brake horsepower-hour.

G. "lb/hr" means pounds per hour.

H. "Operator" means the person or persons responsible for the overall operation of a stationary source.

I. "Owner" means the person or persons who own a stationary source or part of a stationary source.

J. "ppmvd" means parts per million by volume, dry.

K. "Reasonable progress unit" or "RP unit" means an emissions unit selected for an analysis of emission control measures during the second regional haze implementation period for which the department has determined an emission limitation or other measures are necessary to make reasonable progress.

L. "Rolling average" means the weighted average of all data, meeting this Part's quality assurance and quality control requirements, collected during the applicable averaging period. For reasonable progress units equipped with CEMS, a 30-operating-day rolling average is calculated by adding the hourly mass emissions over the previous 30 operating days and dividing that sum by the total operating hours during the same period.

M. "Rolling sum" means the sum of all data, meeting this Part's quality assurance and quality control requirements, collected during the applicable summation period. For reasonable progress units not equipped with CEMS and subject to a multi-unit emission limitation, a 12-month rolling sum is calculated by multiplying each individual unit's hourly mass emission rate by its total operating hours over the previous 12 months and summing the results for all units subject to the multi-unit limit.

[20.2.68.7 NMAC – N, 07/01/2025]

20.2.68.8 SEVERABILITY: If any provision of this Part, or the application of this provision to any person or circumstance is held invalid, the remainder of this Part, or the application of this provision to any person or circumstance other than those as to which it is held invalid, shall not be affected thereby.
[20.2.68.8 NMAC – N, 07/01/2025]

20.2.68.9 CONSTRUCTION: This Part shall be liberally construed to carry out its purpose.
[20.2.68.9 NMAC – N, 07/01/2025]

20.2.68.10 SAVINGS CLAUSE: Repeal or supersession of prior versions of this Part shall not affect administrative or judicial action initiated under those prior versions.
[20.2.68.10 NMAC – N, 07/01/2025]

20.2.68.11 COMPLIANCE WITH OTHER REGULATIONS: Compliance with this Part does not relieve a person from the responsibility to comply with other applicable federal, state, or local laws, rules or regulations, including more stringent controls.
[20.2.68.11 NMAC – N, 07/01/2025]

20.2.68.12 DOCUMENTS: Documents incorporated and cited in this Part may be viewed at the New Mexico environment department, air quality bureau.
[20.2.68.12 NMAC – N, 07/01/2025]
[As of September 2024, the air quality bureau is located at 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico 87505]

20.2.68.13-20.2.68.100 [RESERVED]

20.2.68.101 APPLICABILITY: This Part applies to reasonable progress units as defined in 20.2.68.7 NMAC.
[20.2.68.101 NMAC – N, 07/01/2025]

20.2.68.102 EMISSION LIMITATIONS AND COMPLIANCE DEADLINES:

A. The reasonable progress units listed in Table 1 of Subsection A of 20.2.68.102 NMAC shall not emit or cause to be emitted oxides of nitrogen (NO_x) in excess of the emission limitations shown. The emission limitations must be met as expeditiously as practicable, but in no event later than their respective compliance deadlines.

Table 1 – EMISSIONS LIMITATIONS AND COMPLIANCE DEADLINES

Facility	AI #	RP Unit	Emission Limitation	Compliance Deadline
Bitter Lake Compressor Station	14	C-891	3 g/bhp-hr	0 years
		C-893	3 g/bhp-hr	0 years
Blanco Compressor Station A	1147	A11	0.5 g/bhp-hr	3 years
		A13	0.5 g/bhp-hr	3 years
Blanco C&D Compressor Station	3552	T-C01	13.04 lb/hr	3 years
		T-C02	13.32 lb/hr	3 years
		T-D01	24.22 lb/hr	3 years
Chaco Gas Plant	1148	14	0.5 g/bhp-hr	2 years
Cunningham Station Power Plant	604	1	12.07 lb/hr	3 years
		2	30.05 lb/hr	3 years
Eunice Gas Processing Plant	609	B-01	9 ppmvd @ 3% O_2	2 years
		B-02	9 ppmvd @ 3% O_2	2 years
		C-01	0.5 g/bhp-hr	3 years
		C-02	0.5 g/bhp-hr	3 years
		C-03	0.5 g/bhp-hr	3 years

		C-04	0.5 g/bhp-hr	3 years
		C-05	0.5 g/bhp-hr	3 years
		C-06	0.5 g/bhp-hr	3 years
		C-07	0.5 g/bhp-hr	3 years
Indian Basin Gas Plant	197	ES 06/07	25 ppmvd @ 15% O_2	2 years
		ES 08/09	25 ppmvd @ 15% O_2	2 years
		ES 10/11	25 ppmvd @ 15% O_2	2 years
Kutz Canyon Processing Plant	1158	1	3.34 lb/hr	3 years
		2	3.54 lb/hr	3 years
		4	2.82 lb/hr	3 years
		5	2.38 lb/ hr	3 years
		6	2.36 lb/hr	3 years
		19	3.12 lb/hr	3 years
		20	3.12 lb/hr	3 years
Linam Ranch Gas Plant	589	29	15 ppmvd @ 15% O_2	0 years
		30	25 ppmvd @ 15% O_2	0 years
		31	25 ppmvd @ 15% O_2	0 years
		32B	25 ppmvd @ 15% O_2	1 year
Monument Gas Plant	610	C-01	0.5 g/bhp-hr	3 years
		C-02	0.5 g/bhp-hr	3 years
		C-05	0.5 g/bhp-hr	3 years
		C-06	0.5 g/bhp-hr	3 years
		C-24	0.5 g/bhp-hr	3 years
Mountainair Compressor Station No. 7	1569	701	44.74 ton/yr	3 years
		702		
		703		
		721	9 ppmvd @ 15% O_2	3 years
		722	9 ppmvd @ 15% O_2	3 years
Pecos River Compressor Station	194	A-02	7.28 lb/hr	3 years
		A-03	8.1 lb/hr	3 years
Roswell Compressor Station No. 9	10	903	29 ton/yr	3 years
		904		
San Juan Basin Gas Plant	1177	1	3.96 lb/hr	3 years
		2	4.24 lb/hr	3 years
		3	3.88 lb/hr	3 years
		4	2.78 lb/hr	3 years
		5	2.74 lb/hr	3 years
		6	3.04 lb/hr	3 years
		7	2.88 lb/hr	3 years
South Carlsbad Compressor Station	218	1	15 ppmvd @ 15% O_2	2 years
		2	15 ppmvd @ 15% O_2	2 years
Washington Ranch Storage Facility	220	1	3 g/bhp-hr	0 years
		2	3 g/bhp-hr	0 years

B. The compliance deadlines in Table 1 of Subsection A of 20.2.68.102 NMAC are expressed in years after approval of New Mexico's state implementation plan revision for the second regional haze implementation period by the environmental protection agency.

C. The emission limitation in Table 1 of Subsection A of 20.2.68.102 NMAC for reasonable progress units 701, 702, and 703 at Mountainair Compressor Station No. 7 is a multi-unit limit applicable to all three units combined. Similarly, the emission limitation in Table 1 of Subsection A of 20.2.68.102 NMAC for reasonable progress units 903 and 904 at Roswell Compressor Station No. 9 is a multi-unit limit applicable to both units combined. In the event compliance with either of these multi-unit limits is achieved by replacing the subject units, and the replacement ratio is not 1:1, the limit will apply to all of the replacement units combined, regardless of their number.

D. The owner or operator of a reasonable progress unit that complies with the emission limitations in Table 1 of Subsection A of 20.2.68.102 NMAC using an emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to 15 percent oxygen. [20.2.68.102 NMAC – N, 07/01/2025]

20.2.68.103 OTHER MEASURES: The reasonable progress units listed in Table 2 of 20.2.68.103 NMAC have been retired and removed from their facilities' respective construction permits (or were located at a facility that has permanently ceased operations and closed its construction permit) and shall not be reauthorized as a regulated emission source in any future construction permit modification issued by the department without a new analysis of the emission control measures necessary to make reasonable progress and an EPA-approved regional haze state implementation plan revision.

Table 2 – RETIRED UNITS PROHIBITED FROM REAUTHORIZATION

Facility	AI #	RP Unit	Date Removed from Permit or Permit Closed
Denton Gas Plant	568	005	February 4, 2022
		007	February 4, 2022
Eunice Gas Plant	595	17A	November 5, 2021
		18B	November 5, 2021
		19A	November 5, 2021
		25A	November 5, 2021
		26A	November 5, 2021
		Amine-01	November 5, 2021
		31	November 5, 2021
		111	November 5, 2021
		113	November 5, 2021
Eunice Gas Processing Plant	609	C-08	August 20, 2024
		C-09	May 31, 2024
		C-10	May 31, 2024
		C-11	May 31, 2024
		C-12	May 31, 2024
		C-13	May 31, 2024
Jal #3 Gas Plant	569	4A	November 7, 2022
		5A	November 7, 2022
Kutz Canyon Processing Plant	1158	16	May 11, 2021
		17	May 11, 2021
		18	May 11, 2021
Prewitt Escalante Generating Station	911	S111	June 16, 2021
San Juan Generating Station	1421	S301/E301	December 27, 2022
		S304/E304	December 27, 2022
Saunders Gas Plant	612	C-01	May 31, 2024
		C-02	May 31, 2024
		C-03	May 31, 2024
		C-04	May 31, 2024
		C-05	May 31, 2024
		C-06	May 31, 2024
		C-07	May 31, 2024
		C-08	May 31, 2024
		C-09	May 31, 2024
		G-01	May 31, 2024
		G-02	May 31, 2024
		G-03	May 31, 2024
		A-01	May 31, 2024
		F-01	May 31, 2024

		F-03	May 31, 2024
		I-01	May 31, 2024

[20.2.68.103 NMAC – N, 07/01/2025]

20.2.68.104 MONITORING REQUIREMENTS: Compliance with the emission limitations in Table 1 of Subsection A of 20.2.68.102 NMAC shall be demonstrated as follows.

A. For reasonable progress units one and two at Cunningham Station Power Plant, compliance shall be determined on a 30-operating-day rolling average basis within seven days of the end of each 30-operating-day period, and shall be demonstrated using data from a NO_x continuous emission monitoring system complying with the performance requirements in 40 CFR 75.

B. For reasonable progress units 701, 702, and 703 at Mountainair Compressor Station No. 7 and reasonable progress units 903 and 904 at Roswell Compressor Station No. 9, compliance shall be determined on a 12-month rolling sum basis within seven days of the end of each month, and shall be demonstrated by monitoring operating hours and conducting annual emissions tests using a portable analyzer or EPA reference methods in accordance with the requirements of Subsection D of 20.2.68.104 NMAC. The results of the most recent annual emissions test shall be used to calculate the 12-month rolling sum used to determine compliance.

C. For all other reasonable progress units, compliance shall be demonstrated by conducting annual emissions tests using a portable analyzer or EPA reference methods in accordance with the requirements of Subsection D of 20.2.68.104 NMAC. The arithmetic mean of the results from three separate test runs shall be used to determine compliance pursuant to Paragraph (5) of Subsection D of 20.2.68.104 NMAC.

D. The following requirements apply to annual emissions testing used to demonstrate compliance with the emission limitations in Table 1 of Subsection A of 20.2.68.102 NMAC:

(1) For units with g/bhp-hr emission limits, load shall be calculated using the following equation:

$$\text{Load (hp)} = \frac{\text{Fuel consumption (scf/hr) x Measured lower heating value of fuel (btu/scf)}}{\text{Manufacturer's rated brake-specific fuel consumption (btu/bhp-hr) at 100\% load or best efficiency}}$$

If the manufacturer's rated brake-specific fuel consumption is not available, an alternative load calculation methodology based on available data may be used.

(2) Emissions testing shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. The load and the parameters used to calculate it shall be recorded to document operating conditions at the time of testing and shall be included with the test report.

(3) Emissions testing utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D6522. If a portable analyzer has met a previously approved department criterion, the analyzer may be operated in accordance with that criterion until it is replaced.

(4) The default time period for a test run shall be at least 20 minutes.

(5) An emissions test shall consist of three separate runs, with the arithmetic mean of the results from the three runs used to determine compliance with the applicable emission limitation.

(6) During emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing EPA reference method 19. This information shall be included with the test report.

(7) Stack gas flow rate shall be calculated in accordance with EPA reference method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (btu/scf). The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months before the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using EPA reference methods one through four or through the use of manufacturer provided fuel consumption rates.

(8) Emissions testing shall be conducted at least once per calendar year. Emissions testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subparts ZZZZ or DDDDD of 40 CFR 63, may be used to satisfy the emissions testing requirements of this Part if it meets the requirements of 20.2.68.104 NMAC and is conducted at least once per calendar year.

[20.2.68.104 NMAC – N, 07/01/2025]

20.2.68.105 RECORDKEEPING REQUIREMENTS:

A. For reasonable progress units one and two at Cunningham Station Power Plant, the owner or operator shall maintain records of all NO_x CEMS data. The owner or operator shall also maintain records of periods that the CEMS are inoperative and of all CEMS performance test measurements, performance evaluations, calibration checks, adjustments, and maintenance.

B. For all other reasonable progress units, the owner or operator shall maintain records of all annual emissions tests and operating data used to determine compliance with the emission limitations in Table 1 of Subsection A of 20.2.68.102 NMAC. The records shall include:

(1) make, model, and serial number for the tested engine, turbine, or boiler;

(2) the date and time stamp(s), including GPS of the location, of any monitoring event, including sampling or measurements;

(3) date analyses were performed;

(4) name of the person(s) and the qualified entity that performed the analyses;

(5) analytical or test methods used;

(6) results of analyses or tests;

(7) calculated emissions of NO_x in lb/hr, g/bhp-hr, or ppmvd as appropriate; and

(8) operating conditions at the time of sampling or measurement, including load and the parameters used to calculate it.

C. All records required to be maintained pursuant to Subsections A and B of 20.2.68.105 NMAC shall be kept for a period of at least five years.

[20.2.68.105 NMAC – N, 07/01/2025]

20.2.68.106 REPORTING REQUIREMENTS:

A. Test reports for annual emissions tests required by Subsections B and C of 20.2.68.104 NMAC shall be submitted to the department no later than 30 days after completion of the test.

B. If a 30-operating-day rolling average for reasonable progress units one and two at Cunningham Station Power Plant, a 12-month rolling sum for reasonable progress units 701, 702, and 703 at Mountainair Compressor Station No. 7 or reasonable progress units 903 and 904 at Roswell Compressor Station No. 9, or the results of an annual emissions test for any other reasonable progress unit reveals NO_x emissions in excess of the emission limitations in Table 1 of Subsection A of 20.2.68.102 NMAC, the owner or operator shall submit reports of excess emissions in accordance with Subsection A of 20.2.7.110 NMAC. Reports of excess emissions shall be submitted by the means and in the format specified by the department.

C. The owner or operator of a reasonable progress unit shall respond within three business days to a request for information by the department under this Part. The response shall provide the requested information for each reasonable progress unit subject to the request by the means and in the format specified by the department in its request. If the department requests information pertaining to reasonable progress units at multiple facilities with the same owner or operator, additional time will be given as appropriate.

[20.2.68.106 NMAC – N, 07/01/2025]

HISTORY OF 20.2.68 NMAC: [RESERVED]