July 10, 2020

Attn: Sandra Ely, Michael Baca, Mark Jones, and Kerwin Singleton

New Mexico Environment Department
Harold L. Runnels Building
1190 St. Francis Drive, Suite N4050
Santa Fe, New Mexico 87505
Re: Comments responding to 4-factor analysis submittals from identified oil & gas operators

Dear Ms. Ely, Mr. Baca, Mr. Jones, and Mr. Singleton,

We applaud the New Mexico Environment Department for welcoming public input and engagement throughout the development of its Regional Haze State Implementation Plan (SIP). We encourage the agency to require robust measures in its forthcoming SIP that will result in clearer skies and better air quality in our state and region's Class 1 Airsheds and communities.

We submit the attached expert comments on the four-factor analyses submitted by oil and gas facilities in New Mexico prepared by consultants Megan Williams and Vicki Stamper.

The report identifies numerous errors in operators' 4-factor analyses, including overestimation of interest rate and underestimation of life of controls, high capital estimates, failure to annualize costs in some cases, failure to provide emissions data that reflect a reasonable estimate of current and future actual operations, failure to document sources of emissions data and/or claims made regarding feasibility of controls, and failure to analyze available control options, including electrification.

We value NMED's inclusion of the 20 oil and gas facilities in the state's four-factor list and encourage the state to consider the contents of the attached report. We also request NMED assess control options applicable to source categories within the oil and gas sector from facilities that were excluded from its four-factor list. We urge the state to pursue electrification across the sector and in the alternative ask the state to apply category-wide requirements that would result in effective reductions in visibility-impairing pollution.[1]

We re-emphasize our request that NMED require electrification of engines as an overarching control option. As detailed in our May 22, 2020 cover letter accompanying a report on SCR feasibility at Lean Burn engines, electrification is ultimately the best option for reducing or eliminating emissions of NOx and all other air pollutants from gas-fired engines, thereby better reducing visibility and public health-harming emissions while helping New Mexico achieve its climate goals.

NPCA, Western Environmental Law Center, and other allies across the state are committed to working with the agency, operators, and utilities to identify solutions to overcome spatial and regulatory questions regarding oilfield electrification. We believe a harmonized framework is within reach to aggregate emissions and load, and generate power as a collective instead of operating as a dispersed set of points. Acknowledging the structural questions of oilfield electrification, we urge NMED to move forward on a parallel track with emission-limiting requirements necessitating electrification. Public lands and our communities deserve no less than a forward-looking regional haze plan that will effectively curb existing burdens and mitigate future impacts to air quality.

[1] We refer NMED back to the March 2020 NCPA Oil and Gas Four-Factor Report for consideration of effective control options for oil and gas source categories.

Notwithstanding the above, we offer the following summary takeaways from the attached assessment.

Summary of Effective Controls for Emission Units at New Mexico Oil and Gas Facilities

Combustion Turbines: Based on the revised and additional cost analyses provided in the report, SCR is cost effective for most combustion turbines at the New Mexico Gas Plants evaluated, with the few exceptions potentially being units that limit operating hours (for example, Kutz Canyon Unit 4 appears not to operate much based on its reported NOx emissions in 2016, should limited operations be enforceable, SCR would not be considered cost effective). While several operators summarily dismissed SCR as a feasible pollution control, they failed to support their claims, failing to provide site details or vendor proposals for claims of site constraints or other claimed retrofit difficulties. Although the attached report did not evaluate SCR cost effectiveness for the turbines at Kutz Canyon, Indian Basin or South Carlsbad due to lack of the needed inputs to utilize EPA's SCR cost spreadsheet, based on the other SCR cost analyses that are provided in the report for several similar combustion turbines, SCR should be considered the most cost effective, and most effective in terms of NOx reductions, for all combustion turbines operating more than ~1,000 hours per year. Beyond superior emission-reducing capabilities, SCR is also preferable as water use is not an adverse impact from use of the technology. We further note that SCR combined with SoLoNOx or other dry low-NOx combustion techniques may be the more fitting control option at some units because it would achieve the greatest reduction in NOx emissions.

Lean Burn Engines: As found in NPCA's March 2020 Oil and Gas Four-Factor Report, LEC has been required for retrofit controls—and has been deemed cost effective—for Lean Burn RICE units of a wide size range (e.g., down to 50 hp).[1] In many cases when considering LEC as a potential control, operators failed to specify achievable emission rates, often greatly underestimating the reductions that might be achieved and therefore underestimating the cost effectiveness of the technology. In the accompanying comments on four-factor analyses for oil and gas facilities in New Mexico, LEC is shown to be cost effective for most engines except for those that consistently operate a limited number of hours per year. However, it's important to note that, for some engines, operation may be limited in one year but that may not hold true for the same unit for other years. For example, Targa indicated that "[w]ith regards to the engine usage, Targa attempts to use its engines uniformly but this does not mean equally on a calendar year basis."[2] So, when looking at the cost effectiveness of LEC control for RICE it's important to consider how the engine will be used, on average, over the life of controls rather than just looking at one year that may or may not be representative of that engine's usage in other years. Generally, LEC is cost effective for the specific engine models analyzed operating over 1,000 per year and can achieve 80–90% NOx reduction and reduce NOx emission rates to 2 g/hp-hr and lower. In addition, SCR is shown to be cost effective for Lean Burn engines at the two plants that evaluated SCR for such engines (Roswell Compressor Station No. 9 and Jal No. 3 Gas Plant). Based on those cost analyses as revised in the attached report, SCR should also be considered a cost effective control, with the capability to achieve 90% NOx reduction and reduce NOx emission rates to 1 g/hp-hr.

Rich Burn Engines: As with Lean Burn RICE, control of NOx emissions from Rich Burn RICE has been widely required for retrofit controls—and deemed exceedingly cost effective—for a wide range of units (e.g., down to 50 hp). Specifically, the Rich Burn RICE units at Targa's Saunders Gas Plant NSCR was shown to be extremely cost effective—at under $300 per ton of NOx reduced—based on Targa's own analysis. No other New Mexico facilities submitted cost analyses for Rich Burn RICE but, given that NSCR is often extraordinarily cost effective, NMED should assess the Rich Burn units at the facilities that submitted four-factor analyses, even if those units have NOx emissions that fall below NMED's original cutoffs of 10 lb/hr or 5 tpy; cumulatively, control of NOx emissions from these emissions units using NSCR would be a very cost effective way to achieve additional, meaningful NOx reductions.

Amine Units/Acid Gas Flaring: For amine units and associated acid gas flares at gas sweetening plants, an acid gas injection well with a backup electric acid gas compressor is the minimum level of control of SO2 that should be required. In fact, NMED has required this suite of controls in some settlement agreements, according to information provided in the Targa Eunice Gas Plant and Monument Gas Plant four-factor analyses. For those locations at which an acid gas injection well may not work effectively, then a sulfur recovery unit (SRU) along with an incinerator *and* acid gas scrubber should be used to most effectively control SO2 emissions. Alternatively, a facility could employ both an acid gas injection well and a sulfur recovery unit, as is implemented at the Jal No. 3 amine unit, although improvements should be made at that facility, such as adding an acid gas scrubber to the SRU or routing the acid gas stream from the SRU to the acid gas injection well.   Any maintenance or upset that requires the flaring of the acid gas stream from an amine unit can be a significant source of SO2 emissions and thus redundancy of controls is key for reducing/eliminating SO2 emissions associated with amine units at gas sweetening plants.

In a 2018 presentation from the Air Resources Division of the National Parks Service, entitled "Source Attribution Using Volatile Organic Compound Measurements to Assess Air Quality Impacts at Five National Parks in the Western US," data is shown confirming that Carlsbad is impacted by VOCs from oil and gas activity in the Permian. This further warrants the implementation of the strongest suites of controls at amine units and associated gas flares.

NOx is a visibility-impairing pollutant of interest: We urge the agency to dispel the claim made by several operators that SO_2, not NOx, is the contaminant of interest for visibility impairment in various Class 1 Airsheds. Both pollutants contribute to visibility impairment and emissions of nitrogen oxides must be mitigated to make reasonable progress toward the national goal of restoring natural air quality conditions. Some operators claim that NOx emissions from these pieces of equipment are inconsequential for regional haze purposes, while numerous federal agencies and groups have maintained that reducing NOx is necessary for best reducing visibility-reducing haze.

Colorado State's IMPROVE website makes available a Particulate Matter and Haze Composition Browser (available at http://vista.cira.colostate.edu/Improve/pm-and-haze-composition/), in which there is a map of all Class I areas, with associated 2018 data of PM composition by day. The recent data found in this IMPROVE resource reinforces the importance of controlling NOx in improving visibility in Class 1 airsheds impacted by oil and gas – particularly as this industrial activity has been accelerating greatly in the past several years. As shown in the data for 2018 for Carlsbad Caverns (Figure 1), nitrates are a significant contributor to PM in the winter months.

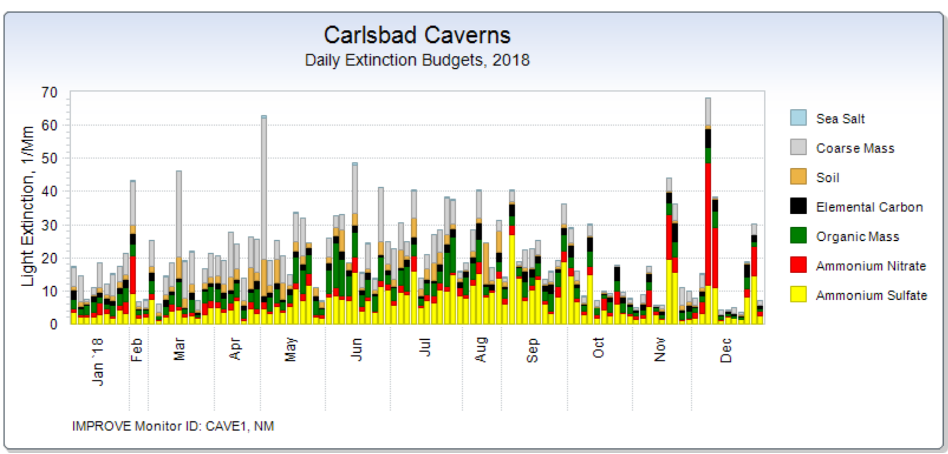

Figure 1.

Moreover, EPA's 2019 Regional Haze Guidance specifies that a state may use a number of screening tools and New Mexico's Q/d approach is a recognized screening methodology that reflects emissions of both SO2 and NOx.

Additional facilities that warrant reduction requirements: The agency's 10 lb/hr and 5 tpy criteria leaves out a wide array of facilities and equipment which contribute significantly to regional haze. In some cases, the agency did not require four-factor analysis for all units at a plant that had PTE greater than these thresholds (such as Units 7 and 8 at Kutz Canyon Gas Plant) - even though the company submitted other four-factor analyses for other units at the same facility.

NPCA has analyzed facilities not identified by NMED as being required to submit four-factor analyses (Figure 2). We have detailed the findings below, including the number of like sources and emissions and emission rate equivalents. In all, we assessed 62 additional facilities, with NOx emissions greater than 50 tpy. The NOx emissions from these 62 additional facilities total 10,711 tons per year according to the 2019 emissions NMED data. Within these 62 facilities, are 209 Lean Burn RICE units (Figure 3):

- 134 Lean Burn RICE units have NOx limits that equate to values greater than 1.0 gr/hp-hr.
- 69 Lean Burn RICE units have NOx limits that equate to values greater than 1.5 gr/hp-hr.
- 17 Lean Burn RICE units have NOx limits that equate to values greater than 2.0 gr/hp-hr.

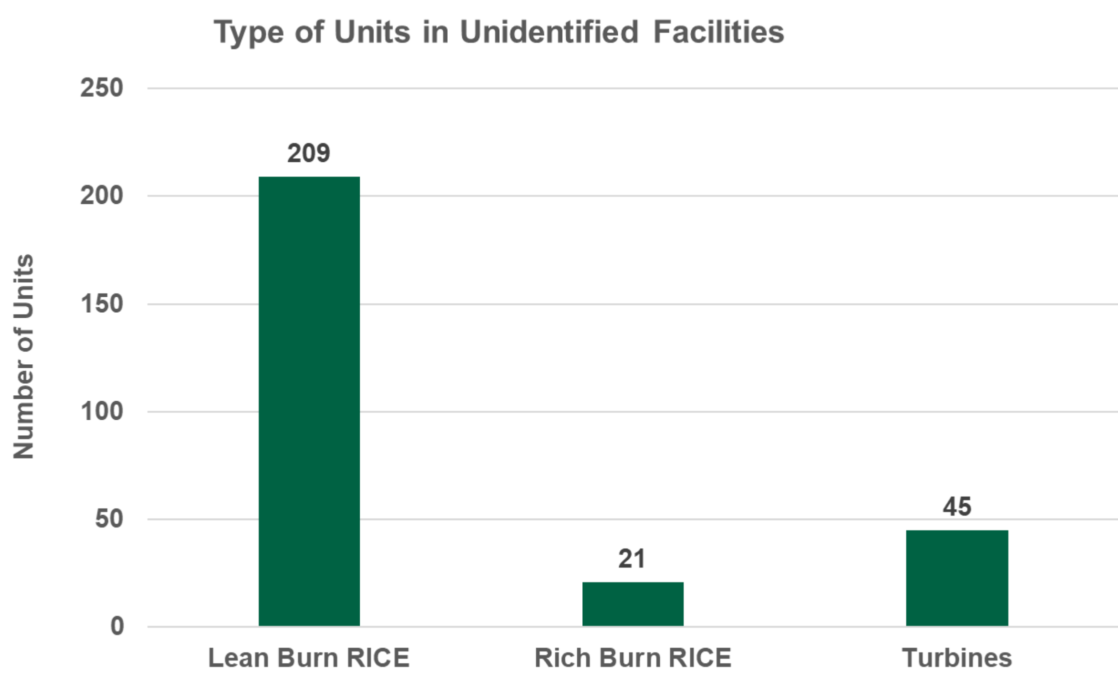

Figure 2.

As discussed above, emission reduction controls such as LEC and SCR are cost effective controls and can be used at these units to achieve NOx limits that equate to 0.15 to 2 g/hp-hr. with a NOx removal efficiency ranging from 87% to 95%. NPCA recommends NMED require a four-factor analysis of any Lean Burn RICE with equivalent NOx emission rates greater than 1.0 gr/hp-hr.

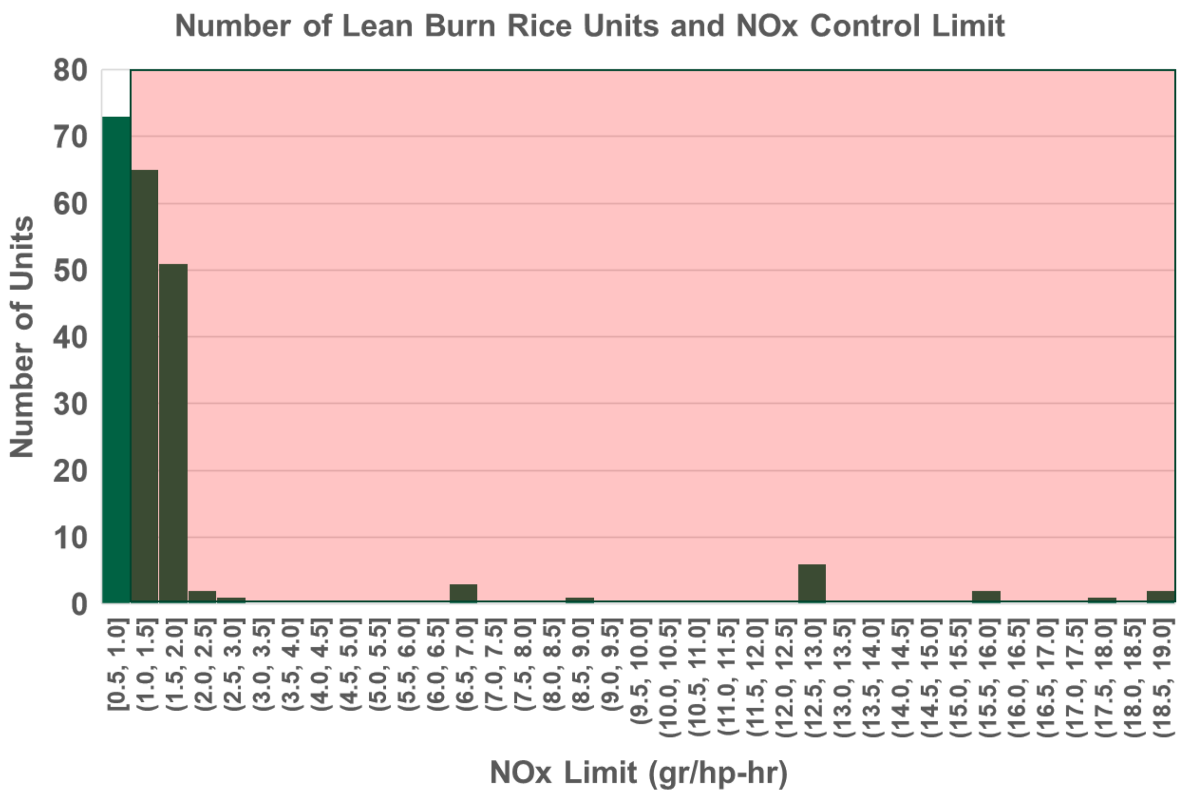

Figure 3.

In addition, we identified 21 Rich Burn RICE units at the 62 facilities not selected by NMED for a four-factor analysis. Of these Rich Burn RICE units, 17 have NOx limits that equate to 1.0 gr/hp-hr (Figure 4). Controlled NOx emission rates from 0.3 to 1.6 g/hp-hr. can be achieved using NSCR with a NOx removal efficiency ranging from 90% to 98%. Given the extremely favorable cost effectiveness of NSCR, NPCA recommends NMED require a four-factor analysis for any Rich Burn RICE with equivalent NOx emission rates greater than 1.0 gr/hp-hr.

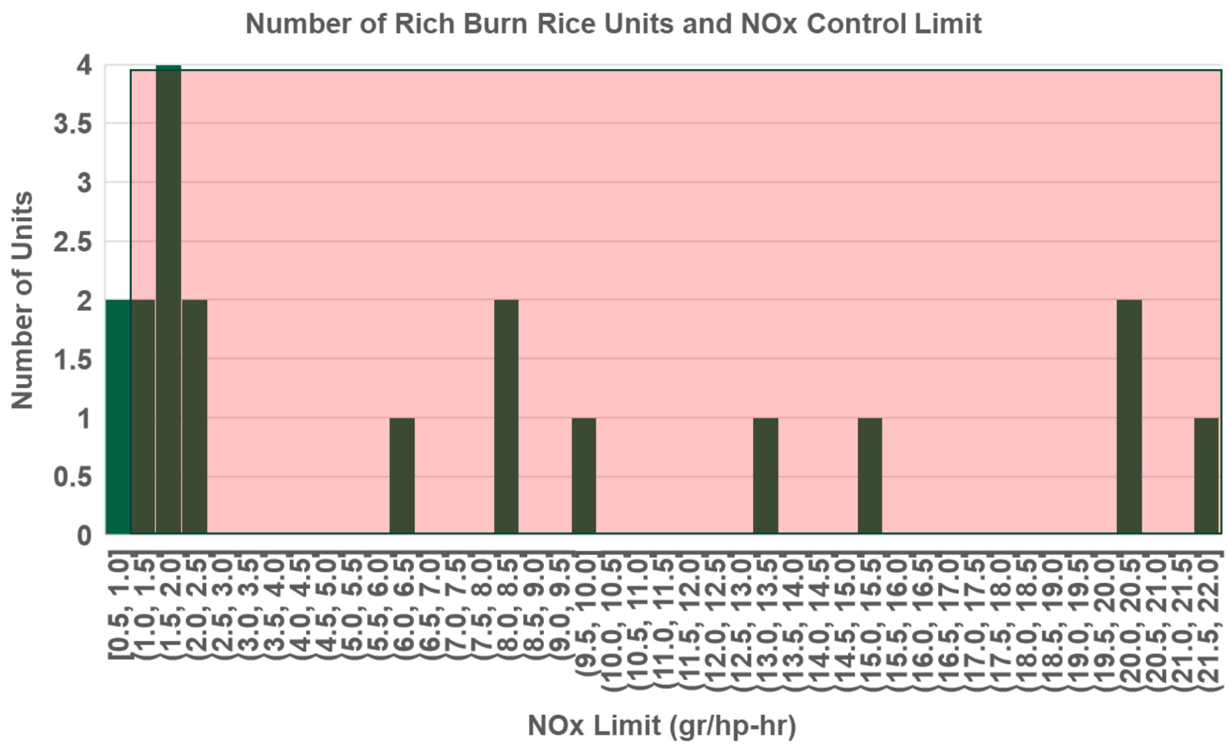

Figure 4.

Lastly, NPCA identified 45 turbines at compressor stations not selected for a four-factor analysis by NMED. Of them, 43 turbines have NOx limits higher than 15 parts per million (ppm) (~0.06 lb/MMBtu) (Figure 5), which reflects a controlled NOx emissions rate achievable with Dry Low NOx Combustors (DLNC) such as SoLoNOx or with SCR. NPCA recommends NMED require a four-factor analysis of these 45 gas turbines with equivalent NOx emission rates greater than 15 ppm.

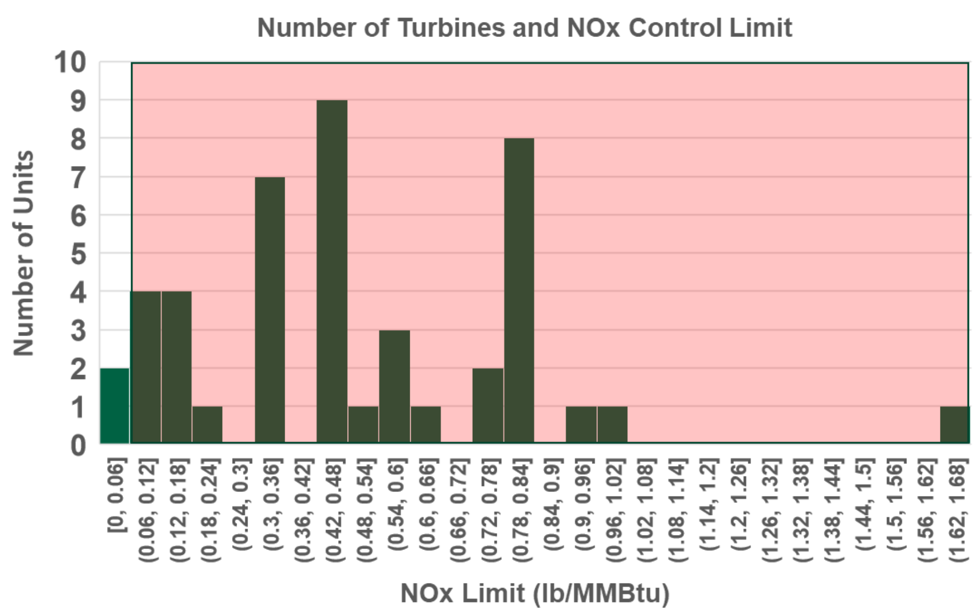

Figure 5.

In closing, we greatly appreciate the opportunity to work with New Mexico Environment Department, and welcome any questions and discussion regarding the attached comments and next steps to ensure the New Mexico Regional Haze Plan results in significant improvements to the visibility at our treasured Class I landscapes and across our communities.

Thank you,

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Assessment of Cost Effectiveness Analyses for Controls Evaluated Four – Factor Analyses for Oil and Gas Facilities For the New Mexico Environment Department's Regional Haze Plan for the Second Implementation Period

July 2, 2020

Prepared for National Parks Conservation Organization

Prepared by:

Vicki Stamper & Megan Williams

Executive Summary

In a March 2020 report on reasonable progress controls for several sources in the oil and gas sector, the authors provided general four-factor analyses of regional haze pollution control options for five source categories in the oil and gas industry, including natural gas-fired engines, combustion turbines, boilers, heaters, diesel-fired engines, and flaring and incineration.[1] That report identified regional haze pollution control options that are cost-effective and have been required by state and local air pollution control agencies through adaptation of emission limitations requiring retrofit of pollution controls for most of these source categories. For example, the report showed that, for natural gas-fired reciprocating internal combustion engines (RICE), cost effective controls include replacing engines with electric compressors, use of nonselective catalytic reduction (NSCR) at rich burn RICE, and use of low emissions combustion (LEC) or selective catalytic reduction (SCR) at lean burn RICE.[2] For natural gas-fired combustion turbines, the report found that the installation of dry low NOx combustion or the use of SCR (or in combination with dry low NOx combustion) is cost effective.[3] And for natural gas-fired heaters and boilers, the use of ultra-low NOx burners and/or SCR were found to be cost effective.[4] We refer the New Mexico Environment Department (NMED) to the March 2020 NCPA Oil and Gas Four-Factor Report for consideration in deciding the pollution controls to require of the New Mexico oil and gas sources for which NMED requested four-factor analyses.

In this document, we provide more specific comments on the cost of controls in the four-factor analyses submitted by oil and gas companies to NMED. The document is organized to provide comments on the facilities' four-factor analyses in order of magnitude of each facilities' "Q/d" value based on 2014 emissions. In the last sections of this document, we provide comments on two additional sources for which NMED did not request four-factor analyses but for which NPCA requested that NMED evaluate based on the facilities' Q/d—the Corona Compressor Station and the Empire Abo Gas Plant. And in the very last section, we provide comments on the four-factor analyses and control options for SO_2 emissions from amine units and flaring including startup, shutdown, malfunction emissions. Specifically, this report provides comments on the company cost analyses and/or provides cost analyses on the listed emission units at the following gas compressor stations and gas processing plants in New Mexico.

[1] *See* National Parks Conservation Association (NPCA) Report Entitled Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, and Flaring and Incineration, prepared by Vicki Stamper and Megan Williams, March 6, 2020 {hereinafter referred to as March 2020 NPCA Oil and Gas Four-Factor Report"].

[2] *Id.* at 10-57.

[3] *Id.* at 61-90.

[4] *Id.* at 116-146.

Emission Units and Facilities Evaluated in this Report

Plant	Units	Type of Emission Unit
Enterprise Chaco Gas Plant	17, 18, 35, 36, & 37	Gas Turbines
	12, 13, 14	2SLB RICE
DCP Eunice Gas Plant	17A, 18A, & 19A, 25A & 26A	Gas Turbines
	31	Amine Unit/SRU incinerator
IACX Bitter Lake Compressor Station	C-891 & C-893	2SLB RICE
Targa Eunice Gas Plant	C-01 thru C-07, & C-09 thru C-12	2SLB RICE
	B-01 & B-02	Gas-fired Boiler
Targa Monument Gas Plant	C-01, C-02, C-04 through C-06, & C-28	2SLB RICE
	AM-01/F-03	Amine Unit/Flare
Targa Saunders Gas Plant	C-01 thru C-09	2SLB RICE
	G-01 thru G-03	4SRB RICE
	AM-10/I-01	Amine Unit/Incinerator
Artesia Gas Plant		Flares
Harvest Four Corners Kutz Canyon Gas Plant	1 thru 6, 19, & 20	Gas Turbines
	16, 17, & 18	2SLB RICE
EPNG Pecos River Compressor	A-01, A-02, & A-03	Gas Turbines
DCP Linam Ranch Gas Plant	29, 30, 31, & 32B	Gas Turbines
	6 thru 11	2SLB RICE
ETC Texas Pipeline Jal No. 3 Gas Plant	4A & 5A	2SLB RICE
Davis Gas Processing Denton Gas Plant	007	Amine Unit/Flare
El Paso Natural Gas Co Washington Ranch Storage Facility	A-01 & B-01	2SLB RICE
Enterprise Blanco C&D Compressor	T-C01, T-C02, & T-D01	Gas Turbines
Harvest Pipeline San Juan Gas Plant	1 thru 7	Gas Turbines
Oxy USA WTP Indian Basin Gas Plant	ES-06/07, 08/09, & 10/11	Gas Turbines
		Amine Units
Enterprise South Carlsbad Compressor	1 & 2	Gas Turbines
El Paso Natural Gas Co Blanco Compressor Station A	A1 thru A14	2SLB RICE
Transwestern Roswell Compressor Station No. 9	903 & 904	4SLB RICE
Transwestern Mountainair Compressor	701, 702, & 703	4SLB RICE
Transwestern Corona Compressor Station	801 & 802, 821 & 822	2SLB RICE
	821 & 822	4SRB RICE
Empire Abo Gas Plant		Sulfur Recovery/Incinerator

RICE Notes: 2SLB: Two-Stroke Lean Burn; 4SLB: Four-Stroke Lean-Burn; 4SRB: Four-Stroke Rich-Burn

In general, the facilities' four-factor analyses are addressed in the order given in the above table, except that amine units and acid gas flares are addressed collectively in Section XXIII at the end of this report.

One overarching control option that NMED should give serious consideration to for lean burn RICE is the electrification of these engines. As was demonstrated in the March 2020 NCPA Oil and Gas Four-Factor Report, electrification of RICE units used for gas compression can be very cost effective just considering the NOx removal benefits, in the range of $1,200-$2,800/ton of NOx removed.[5] And several other pollution control benefits would occur with electrification of engines. From the regional haze perspective, replacing fossil fuel-fired RICE with electric engines would also reduce other visibility-impairing pollutants formed by the engines including volatile organic compounds (VOCs) and, for diesel-fired engines, particulate matter and sulfur dioxide (SO_2). Further, there would be reduced emissions of VOCs from compressor blowdowns. In addition, electric engines would require less maintenance time and have fewer upsets, which would not only reduce high NOx emissions that occur due to startups, shutdowns, and malfunctions, but would also reduce flaring of gas during compressor engine downtime which will reduce VOCs, NOx and, if the gas is sour gas, SO_2. And, of course, the additional significant co-benefit of the reduction in fossil fuel-firing and the reduction in upsets/less maintenance is that greenhouse gases will be greatly reduced. As stated in the NPCA Oil and Gas Report, replacing five RICE engines at a compressor station with electric compressors could eliminate approximately 16,000,000 cubic feet per year of fugitive methane emissions, which along with the greenhouse gas reductions from not burning natural gas in the engines would reflect a reduction of about 12,000 tons per year of carbon dioxide (CO_2) equivalent emissions.[6]

While the analysis of the costs to electrify units in the March 2020 NCPA Oil and Gas Four-Factor Report did not include any costs to upgrade electricity to a facility if needed, there are options that NMED should consider to reduce costs of power upgrades. For example, if more than one facility is located nearby each other, the facilities could partner to bring and/or upgrade electricity to the facilities. In a review of permits for midstream oil and gas facilities on NMED's Emissions Analysis Tool website,[7] there are at least five natural gas processing plants with electric engines in the New Mexico portion of the Permian Basin: 1) Targa -Eunice Gas Processing Plant, 2) Transwestern - Roswell Compressor No. 9, 3) Occidental- South Hobbs Reinjection Compression Facility, 4) DCP – Zia II Gas Plant, and 5) Durango Midstream – Maljammer Gas Plant. NMED should explore whether there are options for these plants to either electrify more engines and/or partner with nearby facilities to enable any necessary electric utility upgrades to electrify currently gas-fired engines. In the northwest part of New Mexico, there are three facilities that are co-located and are actually considered to be one source for Title V purposes despite having different owners: Blanco A Compressor Station,

[5] *Id.* at 44.
[6] *Id.* at 45-46.
[7] https://eatool.air.net.env.nm.gov/aqbeatool/.

Blanco C&D Compressor Station, and San Juan Gas Plant.[8] These facilities are about 1 mile from the city of Bloomfield, so they are not very remote. There are several lean burn RICE that could be replaced with electric engines at these facilities. Given the significant regional haze benefits that could be realized with electrification of engines, NMED should consider these and other options to facilitate implementation of this highly effective control measure.

With respect to other, albeit less effective than electrification control measures that should be considered cost effective for the emission units in the above table, the revised and supplemental cost effectiveness analyses provided herein support the findings of the March 2020 NCPA Oil and Gas Four-Factor Report. First, nonselective catalytic reduction (NSCR) is extremely cost effective for rich burn RICE. Given how cost effective NSCR is and how effective the control is for reducing NOx emissions, NMED should request analyses for all rich burn RICE at the facilities that submitted four-factor analyses, even if those units have NOx emissions that fall below NMED's emission thresholds of 10 pounds per hour (lb/hr) or 5 tons per year (tpy). Installation of NSCR could be a very cost effective way to achieve additional, meaningful NOx reductions at midstream facilities in New Mexico.

With respect to lean burn RICE, low emissions combustion (LEC) and, where evaluated, selective catalytic reduction (SCR), is generally cost effective for lean burn RICE that are operated greater than 500-1,000 hours per year. While several of the four-factor submittals to NMED had very high cost effectiveness values for LEC, those cost effectiveness analyses were often improperly inflated for the reasons discussed herein, including the assumption of low baseline emissions by focusing on a single year of baseline emissions. A single year of operational data of a lean burn engine used in a gas processing facility may not reflect how the unit will operate on average over its lifetime. For example, Targa, indicated that "[w]ith regards to the engine usage, Targa attempts to use its engines uniformly but this does not mean equally on a calendar year basis."[9] If an engine operates less than 1,000 hours per year—consistently, from year to year—LEC may not be cost effective. However, generally, LEC is cost effective for the specific engine models analyzed and can achieve 80–90% NOx reduction and reduce NOx emission rates to 2 g/hp-hr and lower. In addition, SCR is also shown below to be cost effective for lean burn engines at the two plants that evaluated SCR for such engines (Roswell Compressor Station No. 9 and Jal No. 3 Gas Plant). Based on those cost analyses provided herein, SCR should also be considered a cost effective control for lean burn engines, with the capability to achieve 90% NOx reduction and NOx emission rates of 1 g/hp-hr. With respect to claims made about whether SCR can be effectively used at lean burn engines, we refer NMED to the May 21, 2020 report "Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines" that NPCA provided to NMED via a May 22, 2020 letter.

[8] *See* 2/16/2015 Title V Operating Permit No. P048-R3 for Blanco Compressor Station A at 3.

[9] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 6.

For gas-fired combustion turbines, combustion controls and SCR have been required as best available control technology for new gas-fired turbines that power compressors at compressor stations.[10] In addition, combustion controls and SCR have been retrofit to numerous combustion turbines in numerous instances, primarily at electric utility combustion turbines. In revised and supplemental cost analyses presented herein, SCR is shown to be cost effective for most of the combustion turbine evaluated. While several companies made claims of space constraints and retrofit difficulty for SCR, the fact that SCR has been retrofit to numerous existing combustion turbines, coal-fired boilers, refineries, and other emissions sources that were not originally designed with space for SCR indicates that retrofit difficulties can and have been overcome. NMED should not allow a company to ignore evaluation of SCR based on purported retrofit difficulty claims without getting a vendor analysis of retrofit options for this highly effective control. The revised and supplemental cost effectiveness analyses provided herein show that SCR is cost effective for most of the combustion turbines evaluated in the New Mexico oil and gas facility four-factor analyses, unless the turbine has consistently low levels of operation and a low level of baseline emissions (in which case NMED should consider capping operations or emissions as a regional haze control).

For amine units and associated acid gas incineration or flaring, an acid gas injection well with, at the minimum, a backup electric acid gas compressor is the minimum level of control of SO2 that should be required. In fact, NMED has required this suite of controls in some settlement agreements, according to information provided in the Targa Eunice Gas Plant and Monument Gas Plant four-factor analyses. For those locations at which an acid gas injection well may not work effectively, then a sulfur recovery unit along with an incinerator and acid gas scrubber should be used to most effectively control SO2 emissions. Any maintenance or upset that requires the flaring of the acid gas stream from an amine unit can be a significant source of SO2 emissions and thus redundancy of controls is key for reducing/eliminating SO2 emissions associated with amine units at gas sweetening plants.

Below, we provide comments on the cost analyses in the company submittals made to NMED and provide revised and/or supplement cost analyses for the emission units analyzed.

[10] *See*, e.g., January 9, 2019 Registration No. 21599 for Buckingham Compressor Station, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.

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I. Enterprise Field Services Chaco Gas Plant

The Enterprise Field Services (Enterprise) Chaco Gas Plant is a natural gas processing plant. NMED has described the plant process as follows:

> The function of the facility is to receive field natural gas, process the gas through removal of water, then extraction/separation of natural gas liquids (NGL) through a cryogenic process. NGL recovered are then treated to remove carbon dioxide and hydrogen sulfide. Recovered NGL is delivered to a pipeline for transport to fractionation facilities downstream. The facility compresses/pumps residue and sales natural gas for distribution through mainline natural gas pipelines.

3/1/2019 Statement of Basis for Title V Permit Significant Modification (Permit Nos. 1555-M6 (revisions through M6R2) and P116-R2M1 at 1.

According to the permit, the plant includes several 2-stroke and 4-stroke lean-burn RICE, several natural gas-fired turbines, a diesel generator, flares, and a heater.[11] In Enterprise's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- General Electric (GE) Frame 5 Turbines: Units 17 and 18
- Solar Mars T-15000 Turbines: Units 35, 36, and 37
- Clark TLA-10 2SLB SI-RICE Engines: Units 12, 13, and 14.[12]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tons per year (tpy), which is the criteria established by NMED to identify sources subject to four-factor analyses.[13] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

Enterprise used an 8.38% interest rate in the cost analyses for all the controls evaluated in its 4-factor analyses.[14] This is an unreasonably high interest rate for cost effectiveness analyses. EPA's Control Cost Manual indicates that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[15] The current bank prime rate is 3.25%.[16] The highest

[11] Title V Operating Permit P116-R2M1 for Chaco Natural Gas Processing Plant at A6 to A8.
[12] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 1-2.
[13] *Id.*
[14] *Id.* at Section 8.0 Supporting Documentation.
[15] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at:

the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[17] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. However, in a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[18] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. Enterprise's use of an 8.38% interest rate is unreasonably high and overstates the cost effectiveness of pollution controls evaluated in the four-factor analyses.

B. GE Frame 5 Turbines: Units 17 and 18.

Units 17 and 18 at the Chaco Gas Plant are 19,500 horsepower natural gas-fired turbines that were constructed in 1970 and 1971.[19] The units each have a NOx emissions limit of 78.5 lb/hr and 344 tpy.[20] For these units, Enterprise identified water or steam injection as viable combustion controls for NOx but claimed that dry low NOx combustors were not available for retrofit to these types of gas turbines.[21] Enterprise claimed that SCR installation was not possible for these gas turbines, due to the size estimates of the SCR.[22] Presumably, Enterprise is claiming issues of retrofit difficulty. There is no question that SCR is technically feasible for natural gas-fired combustion turbines, including those used at compressor stations.

1. Evaluation of Baseline NOx Emissions.

According to the company's cost analysis for water/steam injection, Unit 17 has an actual NOx emission rate of 29.15 lb/hr (54.7 ppm) and Unit 18 has an actual NOx emission rate of 29.15 lb/hr (48.7 ppm) based on 2016 stack test data.[23] These actual emission rates are much lower than the units' 78.5 lb/hr allowable NOx emission rates, so either the 2016 stack test data was not performed while the engines were operating at maximum capacity, or the allowable NOx

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https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

[16] https://www.federalreserve.gov/releases/h15/.

[17] https://fred.stlouisfed.org/series/DPRIME.

[18] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

[19] Title V Operating Permit P116-R2M1 for Chaco Natural Gas Processing Plant at A6 to A8.

[20] *Id.* at A10.

[21] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant, Part 3 of zipped file available on NMED's Emission Analysis Tool, at pdf page 11.

[22] *Id.* at 2-4.

[23] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 82- to 8-3.

emission rates have been set unreasonably high. NMED should present information on the 2016 stack test data so the circumstances of the stack tests can be reviewed. In addition, NMED and Enterprise should review other stack tests for these units to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. For example, in the November 2007 Title V renewal application for the Chaco Gas Plant, the actual emission test results were listed for Unit 17 as 49.22 lb/hr when the unit was operating at 83% load and was listed for Unit 18 as 69.8 lb/hr when the unit was operated at 89% load.[24] In addition, test data from 1995 was also included in the November 2007 permit application which shows Unit 17 with a NOx emission rate of 78.7 ppm @15% oxygen (O_2) and 90.6 ppm @ 15% O_2 and Unit 18 with a NOx emission rate of 93.4 ppm @ 15% O_2 and 109.5 ppm @15% O_2.[25] Clearly, these actual emission rates from Enterprise's 2007 Title V permit application are significantly higher than the 29.15 lb/hr (48.7-54.7 ppm) NOx emission rates that the company's four-factor cost effectiveness analysis is based upon. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on an estimate of emissions expected in 2028 pursuant to EPA's regional haze guidance for the second implementation period.[26]

2. Evaluation of Water Injection and Steam Injection for NOx Control

As a result of assuming what appears to be unreasonably low NOx emission rates for current emissions from the GE Frame 5 turbines, Enterprise also assumed an unreasonably low level of NOx reduction in its cost effectiveness analysis of water injection and steam injection. Specifically, Enterprise only assumed a 15% NOx reduction from water or steam injection.[27] While Enterprise cites EPA's AP-42 emission factor documentation for the 15% control with water or steam injection, EPA's AP-42 states that such controls can achieve 60% or higher NOx removal.[28] EPA's 1993 Alternative Control Techniques Document (ACT) for NOx emissions from Stationary Gas Turbines, cited in EPA's AP-42 emission factor documentation, states that NOx rates in the range of 25 to 42 ppmv can be achieved with water or steam injection as gas-fired combustion turbines.[29] For the Frame 5 turbines installed at the Chaco Gas Plant which, based on the 1978 year of manufacture indicated in the Title V permit, were presumably Model MS5001P,[30] EPA's 1993 Gas Turbine ACT listed the uncontrolled NOx emissions as 142 ppmv, dry, at 15% O_2.[31] Thus, a reduction to 25-42 ppm with water or steam injection would equate

[24] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf page 11.
[25] *Id.* at pdf pages 14 and 15.
[26] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation period, at 29.
[27] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-3.
[28] EPA, AP-42 Emission Factor Documentation, at 3.1-6.
[29] *See* EPA. Alternative Control Techniques Document – NOx Emissions form Stationary Gas Turbines, EPA-453/R-93-007, January 1993, at 2-5 [hereinafter EPA 1993 Gas Turbine ACT].
[30] *See* https://www.ccj-online.com/3q-2012/special-report-the-venerable-frame-5-gas-turbine/.
[31] *See* EPA. Alternative Control Techniques Document – NOx Emissions form Stationary Gas Turbines, EPA-453/R-93-007, January 1993, at 2-3.

to a 70% to 82% reduction in NOx emissions with water or steam injection from EPA's listed uncontrolled NOx rate of 142 ppmv. If the uncontrolled emissions of Units 17 and 18 are truly in the range of 48.7 to 54.7 ppm as indicated in Enterprise's 4-Factor analyses (assuming this is parts per million by volume at 15% oxygen, which NMED should confirm) and that is a reasonable projection of NOx emission rates into 2028 despite prior emission tests that were much higher than these levels, it seems very likely that the water or steam injection could reduce NOx down to at least 25 ppmv @ 15% O_2, which would be a reduction in emissions of 56% at Unit 17 and of 50.7% at Unit 18. Thus, NMED must require that Enterprise evaluate water or steam injection for Units 17 and 18 assuming a 25 ppmv @ 15% O_2 NOx rate could be achieved.

With respect to the life assumed of water or steam injection, Enterprise only assumed a 15-year life of these controls.[32] Enterprise did not provide any justification for assuming such a short life of water or steam injection. As discussed in NPCA's March 2020 report, the life of water or steam injection should be the life of the combustion turbines. In NPCA's March 2020 report, we assumed a 25-year life of water or steam injection.[33]

In terms of Enterprise's costs for water injection or steam injection, the company's capital costs seem very high for the size turbines, based on a comparison to the 1999 Department of Energy (DOE) report entitled "Cost Analyses of NOx Control Alternatives for Stationary Gas Turbines," which is cited in several EPA and State documents on the costs of NOx controls at gas turbines.[34] In that 1999 DOE report, the costs of water or steam injection for a slightly larger gas turbine, a GE LM2500 turbine which is of 22.7 megawatt capacity or about 30,400 hp, the capital cost in 1999 dollars of water injection was estimated to be $1,083,175.[35] Although EPA's Control Cost Manual advises against escalating costs more than five years because it can lead to inaccuracies in price estimation,[36] just using the Chemical Engineering Plant Cost Indices between 1999 and 2018, the DOE's 1999 costs of water injection for a larger GE LM2500 gas turbine would increase to $1.67 million.[37] Using a different cost index specific to oil refineries, the Nelson-Farrar index, the 1999 costs of water injection increase from $1.0 million to $1.88 million as of 2016 (the most recent annual Nelson-Farrer cost index found online).[38] Yet,

[32] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 6-1.
[33] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 64.
[34] Bill Major, ONSITE SYCOM Energy Corporation, and Bill Powers, Powers Engineering, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, prepared for U.S. Department of Energy, November 5, 1999, available at: https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf [hereinafter "1999 DOE Report"].
[35] *Id.*, Appendix A at A-4.
[36] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.
[37] Based on multiplying the 1999 cost estimate for water injection from the 1999 DOE report by the ratio of the CEPCI indices for 2018 to 1999 (603.1/390.6).
[38] Based on multiplying the 1999 cost estimate for water injection from the 1999 DOE report by the ratio of Nelson-Farrar indices for 2016 to 1999 (2598.7/1497.2).

Enterprise's capital cost estimate for water injection at Units 17 and 18 was $6.6 million, more than three times the escalated capital costs from the 1999 DOE report based on either the CEPCI index or the Nelson-Farrar index. Thus, Enterprise's capital cost estimate of water injection for a smaller capacity gas turbine at Units 17 and 18 seems very high. Further, the inspection and operating costs of water injection, which Enterprise stated would be $1,238,327 per year,[39] are not explained or documented and seem unreasonably high. NMED must request more details and support for these cost estimates of water injection and steam injection at Units 17 and 18.

We addressed just some of these issues to revise Enterprise's cost effectiveness analyses to reflect 1) a 4.7% interest rate (instead of 8.38%), 2) a 25-year life of water or steam injection (instead of an assumed 15-year life), 3) a controlled NOx rate with water or steam injection of 25 ppmvd at 15% O_2, and 4) revising Enterprise's baseline emissions to reflect EPA's NOx rate for uncontrolled GE Frame 5 gas turbines of 142 ppmvd[40] and a controlled NOx rate of 42 ppmvd. With the revisions listed in items 1 through 3 above, Enterprise's cost effectiveness of water or steam injection reduction from approximately $107,000 to $149,000/ton of NOx removed to $24,500- $38,692/ton, and it is important to note that no changes were made to Enterprise's own seemingly high estimates for capital and operating costs of water or steam injection. Revising Enterprise's cost estimates to use EPA's uncontrolled NOx rate for the turbine models of 142 ppmvd and a controlled NOx rate of 42 ppmvd with water or steam injection (the least stringent NOx emission rate that EPA indicates can be met with the control), reduces cost effectiveness of these controls to $7,300-$10,500/ton. Again, these revisions do not reflect any changes to Enterprise's seemingly high capital and operating costs for water or steam injection.

In its identification of energy and non-air quality environmental impacts of compliance, Enterprise did not list water use as an adverse environmental impact, but it is an issue to be concerned with for water injection.[41] That is why dry low NOx combustion, if available (which Enterprise claims is not available for the Unit 17 and 18 turbine models) or SCR are more preferable choices for NOx control from gas-fired turbines in New Mexico.

[39] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 8-2 to 8-3.
[40] *See* EPA. Alternative Control Techniques Document – NOx Emissions form Stationary Gas Turbines, EPA-453/R-93-007, January 1993, at 2-3.
[41] *See* March 6, 2020 NPCA Oil and Gas Four-Factor Report at 67-68.

3. Evaluation of SCR for Units 17 and 18 Gas Turbines.

Enterprise did not evaluate SCR for the Units 17 and 18 gas turbines, stating that it was "not possible to install these units at the Chaco facility" due to "the amount of buffer space needed to maintain accessibility to equipment and to avoid compromising worker safety."[42] While the facility and gas turbines may not have been originally designed to have space to accommodate SCR, that is typically the case with most SCR retrofits. As such, there have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints. For example, for many large coal-fired power plants, SCR reactors have been elevated above the air preheaters. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new foundations to make way for the SCR reactor.[43] Thus, before NMED accepts a very brief claim of retrofit difficulty of SCR at any emissions unit being evaluated for reasonable progress controls, it is imperative that NMED ask Enterprise for a site plan and photos that show whatever space constraints are being claimed, and that NMED asks Enterprise to consult with SCR vendors for options for SCR installation at the gas turbines of Units 17 and 18. For Unit 18, a schematic of the unit provided in the 2007 Title V permit application shows an oil heat recovery unit labeled as "out of commission."[44] Perhaps extracting that heat recovery unit out of the unit would enable for the relocation of the stack and space for the SCR. Unit 17 is also shown as being equipped with a heat recovery unit[45] and it is not clear if that is still operating or whether it could also be removed to make room for an SCR installation. In addition, there may be other options for the location of the SCR system. Depending on the proximity of the gas turbines, it is possible that one SCR reactor could be used by both Units 17 and 18, which would reduce costs and potentially be easier to install at the site. NMED must require all possibilities for SCR installation be evaluated and documented by Enterprise. The state must not simply discount this highly effective NOx control based on a claim of some retrofit difficulty.

In terms of the costs of SCR control, NPCA's March 2020 Oil and Gas Four-Factor Report showed the cost effectiveness in 1999 dollars for SCR achieving about 90% NOx reductions would range from $2,000/ton to $3,400/ton for a 5 MW combustion turbine (~6800 hp engine) depending on the operating capacity factor, and costs decrease for larger turbines like Units 17 and 19 which are approximately 19,500 hp engines.[46] For much larger combustion turbines of 75 MW

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[42] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-4.
[43] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, available at https://www.onepetro.org/conference-paper/SPE-66501-MS.
[44] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf page 16.
[45] *Id.*
[46] *See* NPCA March 2020 Oil and Gas Four-Factor Report at 75.

generating capacity (~100,500 hp), cost effectiveness of SCR was significantly lower in the range of $560-$850/ton depending on operating capacity factor.[47]

To get an idea of the costs for SCR at Units 17 and 18 in current dollars, one can use EPA's SCR cost spreadsheet made available as part of EPA's Control Cost Manual.[48] While the EPA SCR cost spreadsheet was not specifically designed for simple cycle gas combustion turbines, it can be modified to estimate SCR cost for gas-fired combustion turbines. It seems likely that this EPA cost spreadsheet for boilers will overestimate the cost of SCR for natural gas-fired combustion turbines. This is because gas turbines, particularly those used in power generation, are routinely equipped with SCR systems, and for simple cycle gas turbines, the SCR systems are typically placed in an enclosure attached to the combustion turbine exhaust.[49] Boilers are not as commonly equipped with SCR compared to natural gas combustion turbines, and the SCR placement is more complicated with its placement usually between the economizer and air preheater and upstream of pollution control equipment. This EPA SCR cost spreadsheet is based on cost assumptions from the Integrated Planning Model (IPM) and those costs are, in turn, based on actual SCR retrofit costs for boilers.[50] Because SCR systems are more commonly applied at gas combustion turbines, especially those used in power generation (including simple cycle turbines) and because SCR installation at a simple cycle combustion turbine is often more straightforward than at a boiler, the EPA SCR cost spreadsheet likely overestimates the cost of SCR for a natural gas-fired combustion turbine. Thus, to generate a more current cost estimate of SCR for the natural gas-fired combustion turbines of Units 17 and 18 at the Chaco Gas Plant, EPA's SCR cost spreadsheet was also used to estimate SCR cost effectiveness.

For this analysis, Enterprise's claimed baseline NOx emission rates of 54.7 ppm and 48.7 ppm for Units 17 and 18, respectively, were used. These are assumed to be reflective of ppm by dry volume at 15% oxygen. As previously discussed, NMED should ensure that this 2016 test data reflects operations at maximum operating capacity and ensure that these emission rates are a reasonable projection of NOx emissions as of 2028, especially given that past NOx emission rates have been identified as significantly higher than these NOx rates. The company's actual NOx rates were converted to lb/MMBtu emission rates using a conversion formula from EPA's

[47] *Id.*
[48] While this spreadsheet was not identified to be used with natural gas-fired combustion turbines, as EPA states that its use is for boilers fired by coal, fuel oil, or natural gas with heat input greater than 250 MMBtu/hr or generating capacity greater than or equal to 25 MW, the spreadsheet can be used to estimate SCR capital and operations costs for any fossil fuel-fired unit as long as the necessary input data is available. In fact, it has been utilized by several oil and gas facilities in their four-factor analyses to NMED.
[49] *See*, e.g., Managing the Catalysts of a Combustion Turbine Fleet, Power, April 30, 2012, under 2. Typical simple cycle SCR. Available at https://www.powermag.com/managing-the-catalysts-of-a-combustion-turbine-fleet/.
[50] *See* Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, SCR Cost Development Methodology, January 2017, at 1, available at https://www.epa.gov/airmarkets/ipm-v6-emission-control-technologies-attachment-5-3-scr-cost-development-methodology.

1993 Gas Turbine ACT.[51] Enterprise's ppm NOx baseline rates thus were converted to 0.22 lb/MMBtu for Unit 17 and 0.20 lb/MMBtu for Unit 18. With this data, the authors input unit-specific information into EPA's SCR cost spreadsheet to estimate cost effectiveness of SCR at Units 17 and 18, including the altitude of the site listed in the 2007 Title V permit application of 6,020 feet and the exhaust gas temperature of 766 degrees Fahrenheit.[52] Two different SCR control levels were assumed: approximately 70% control to achieve a 15 ppmvd NOx rate and a 90% control efficiency to achieve approximately a 5 ppmvd NOx emission rate. In an analysis of SCR cost effectiveness from an uncontrolled gas turbine, NESCAUM estimated that a 15 ppmvd NOx rate reflective of 90% NOx control (from uncontrolled NOx rates) could be achieved with SCR.[53] As stated above, the 2016 baseline emission rates assumed by Enterprise are much lower than worse case NOx rates, and a 15 ppmvd limit only reflects 70% control across the SCR, when such controls can achieve 90% or greater NOx reduction. Thus, two levels of NOx emission reduction were assumed to reflect a low and a high level of NOx reduction with the SCR. The heat value of the fuel and hourly heat input for Units 17 and 18 identified in Part 3 of Enterprise's 2007 Title V permit application (i.e., 1,245 Btu/standard cubic feet and 181 MMBtu/hr)[54] were assumed to reflect current operations at the units. With Enterprise's 2016 actual annual NOx emissions and its reported ppm NOx emissions and the reported heat value of the fuel, actual annual gas consumption rates were estimated for each unit for input into the SCR cost spreadsheet. Capital costs were annualized applying a cost recovery factor using a 4.7% interest rate and a 25-year life which EPA has identified as typical for SCR systems used at industrial boilers.[55] Last, two different reagent types were evaluated: 29% aqueous ammonia and 50% urea solution. Urea was evaluated due to concerns raised by Enterprise in the use of ammonia as a reagent because, with urea used as a reagent, the concerns from hazards of using pressurized ammonia do not apply. The results of these analyses are provided in Table 1 below.

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[51] *See* EPA, Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993, Appendix A which has conversion equations for natural gas-fired combustion turbines.
[52] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf pages 12 and 13.
[53] NESCAUM 2000 Status Report at III-21 through III-24 and at III-40 (see references 11, 16, 9, 14, and 15).
[54] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf pages 11-12.
[55] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

Table 1. Cost Effectiveness of SCR at Chaco Gas Plant Units 17 and 18 GE Frame 5 Gas Combustion Turbines, Using EPA's SCR Cost Calculation Spreadsheet for Boilers

Unit	Assumed NOx Removal Efficiency with SCR	Capital Cost of SCR (2018 $)	Annual O&M Costs with 29% Ammonia	Annual O&M Costs with Urea	NOx Removed from 2016 Baseline, tpy	Cost Effectiveness of SCR with Ammonia (2018 $), $/ton	Cost Effectiveness of SCR with Urea (2018 $), $/ton
17	72%	$5,725,135	$95,677	$125,129	79	$6,264	$6,638
17	90%	$5,725,135	$100,385	$137,200	98	$5,059	$5,433
18	70%	$5,725,135	$110,586	$144,582	91	$5,591	$5,965
18	90%	$5,725,135	$116,197	$159,905	117	$4,396	$4,771

The cost estimates of SCR based on EPA's boiler SCR cost spreadsheet project costs for SCR that are significantly lower than Enterprise's water or steam injection capital cost estimates, which were projected to range from $6.6 to $8.7 million, as well as the company's annual operating cost estimates, which ranged from $1.2 to $1.8 million per year.[56] Given that SCR can achieve much higher levels of control at much lower costs than water or steam injection, NMED must require Enterprise to more fully evaluate the ability to install SCR at Unit 17 and/or 18. Ninety percent control should be readily achievable with SCR at these units to meet a NOx emission rate of 5 ppmvd (0.02 lb/MMBtu). Before allowing Enterprise to dismiss SCR due to claims that it is not feasible to locate one or more SCR reactors at Units 17 and 18, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at Units 17 and 18, including any potential options for a shared SCR system between Units 17 and 18 if such options exist. SCR can be a very effective method for reducing NOx emissions from the Units 17 and 18 gas turbines and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for Units 17 and 18 at the Chaco Gas Plant.

C. Solar Mars T-15000 Turbines

Units 35, 36, and 37 at the Chaco Gas Plant are 15,000 horsepower natural gas-fired Solar Mars T-15000 combustion turbines that were constructed in 1996.[57] The units each have a NOx emissions limit of 76.2 lb/hr and 333.6 tpy.[58] For these units, Enterprise identified dry low NOx combustors made by the turbine manufacturer ("SoLoNOx") as a viable control technology, but claimed that SCR was not possible for these turbines due to retrofit difficulty; namely, due to the size estimates of the SCR.[59] As previously discussed, there is no question that SCR is

[56] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 8-1 to 8-3.
[57] Title V Operating Permit P116-R2M1 for Chaco Natural Gas Processing Plant at A7.
[58] *Id.* at A11.
[59] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-4.

technically feasible for natural gas-fired combustion turbines, including those used at compressor stations.

1. SoLoNOx at Units 35, 36, and 37

Enterprise evaluated SoLoNOx for the Solar Mars turbines of Units 35, 36, and 37, stating that it could reduce NOx concentrations down to 15 ppmv which reflects 85-88% NOx reduction efficiency from the 2016 stack test data that Enterprise assumed as baseline emissions.[60] NMED must ensure that the 2016 stack test data reflect actual emissions from the units and expected actual emissions from the units in 2028.

Enterprise's cost estimates for SoLoNOx at Units 35, 36, and 37 are based on vendor quotes from Solar Turbines.[61] Enterprise then determined cost effectiveness of SoLoNOx controls to meet a 15 ppmv NOx emissions rate, using an interest rate of 8.38% and an assumed life of controls of 20 years.[62] As previously discussed, a 4.7% interest rate is more reflective of current and likely near future interest rates. In terms of the life of SoLoNOx controls, the combustors should last the life of a combustion turbine, which is at least 25 years. Thus, to more accurately reflect cost effectiveness for the SoLoNOx controls at Units 35, 36, and 37, Enterprise's cost effectiveness calculations were revised to reflect a 4.7% interest rate and a 25-year life of controls. The revised costs are reflected in Table 2.

Table 2. Revised Cost Effectiveness of SoLoNOx at Units 35, 36, and 37 of the Chaco Gas Plant, to Reflect a 4.7% Interest Rate and a 25 Year Life

Unit	Enterprise's Total Annual Costs of SoLoNOx (at 8.38% Interest and 20-Year Life)	Enterprise's Cost Effectiveness at 8.38% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25-Year Life
35	$715,215	$6,800/ton	$512,744	$4,875/ton
36	$688,967	$6,668/ton	$495,494	$4,796/ton
37	$693,345	$9,434/ton	$498,371	$6,781/ton

Thus, SoLoNOx at Units 35, 36, and 37 should be considered much more cost effective than reflected in Enterprise's cost analysis.

[60] *Id.* at 2-2.
[61] *Id.* at 3-2.
[62] *Id.* at 8-4 through 8-6.

2. SCR at Units 35, 36, and 37

As with Units 17 and 18, Enterprise did not evaluate SCR for Units 35, 36, and 37, claiming it was "not possibly to install these units at the Chaco facility" due to "the amount of buffer space needed to maintain accessibility to equipment and to avoid compromising worker safety."[63] For the reasons discussed above in Section I.B.3, NMED must request more information and documentation before allowing Enterprise to dismiss SCR due to claims that it is not feasible to locate one or more SCR reactors at Units 35, 36, and 37. NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at Units 35, 36, and 37, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions from the Units 35-37 gas turbines and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for Units 35-37 at the Chaco Gas Plant.

There are two options for the evaluation of cost effectiveness of SCR at Units 35, 36 and 37: One is to consider SCR as a control option without SoLoNOx installed. A second option is to consider SoLoNOx plus SCR as the maximum achievable reductions in NOx emissions. As discussed in the NPCA March 2020 Oil and Gas Four-Factor Report, SCR has recently been proposed to be installed at several compressor stations.[64] Once such compressor station is the Buckingham Compressor station to be located in Virginia. That compressor station was proposed to be constructed with Solar Mars combustion turbines equipped with SoLoNOx and SCR to achieve a NOx emission rate of 3.75 ppmv @ 15% oxygen.[65] SCR installed along with the SoLoNOx combustion control could achieve 96 to 97% reduction in NOx emissions from Units 35, 36, and 37. However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as best available control technology (BACT) or Lowest Achievable Emission Rate (LAER) for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[66]

To get an idea of the costs for SCR at Units 35, 36, and 37 in more current dollars, we used EPA's SCR cost spreadsheet made available as part of EPA's Control Cost Manual. Two different costs analyses were completed for these comments: 1) SCR plus SoLoNOx to achieve a 3.75 ppmv NOx rate and 2) SCR by itself to achieve 15 ppmv. The costs analyses were based on the

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[63] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-4.
[64] NPCA March 2020 Oil and Gas Four-Factor Report at 89.
[65] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.
[66] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.

use of a 50% urea solution as the reagent. As shown in Table 1 above, if a 29% aqueous ammonia reagent is used, the cost effectiveness will be lower than if urea is used – thus, these cost estimates reflect a worst case estimate. The company's actual NOx rates and the emission limits evaluated were converted to lb/MMBtu emission rates for input into EPA's SCR spreadsheet using a conversion formula from EPA's 1993 ACT for Gas Turbines.[67] With this data, unit-specific information was input into EPA's SCR cost spreadsheet to estimate cost effectiveness of SCR at Units 35-37, including the altitude of the site listed in the 2007 Title V permit application of 6,020 feet and the exhaust gas temperature of the turbines of 907 degrees Fahrenheit.[68] The heat value of the fuel and hourly heat input for Units 35-37 identified in Part 3 of Enterprise's 2007 Title V permit application (i.e., 900 Btu/standard cubic feet[69] and 91.2 MMBtu/hr)[70] were assumed to reflect current operations at the units. With Enterprise's 2016 actual annual NOx emissions and its reported ppm NOx emissions and the reported heat value of the fuel, actual annual gas consumption rates were estimated for each unit for input into the SCR cost spreadsheet. Capital costs were annualized applying a cost recovery factor using a 4.7% interest rate and a 25-year life which EPA has identified as typical for SCR systems used at industrial boilers.[71] To determine cost effectiveness of SoLoNOx plus SCR, the revised annualized costs of SoLoNOx at a 4.7% interest rate and a 25 year life were added to the costs of SCR to reduce NOx emissions from 15 ppmv to 3.75 ppmv. The results of these analyses are provided in Table 3 below.

Table 3. Cost Effectiveness of SCR Plus SoLoNOx at Chaco Gas Plant Units 35, 36, and 37 Solar Mars T15000 Turbines to Reduce NOx to 3.75 ppmv, Using EPA's SCR Cost Calculation Spreadsheet with Urea Reagent (2018 $)

Unit	Revised Total Annual Costs of SoLoNOx (at 4.7% Interest and 25-Year Life)	Capital Cost of SCR to Reduce NOx from 15 ppmv to 3.75 ppmv	Annual O&M Costs of SCR	Total Annual Costs of SCR	Total Annual Costs of SoLoNOx Plus SCR	NOx Reduced with SoLoNOx and SCR, tpy	Cost Effectiveness of SoLoNOx plus SCR, $/ton
35	$512,744	$3,666,834	$53,222	$308,349	$821,093	115.9	$7,082/ton
36	$495,494	$3,666,834	$53,361	$308,488	$803,982	114.2	$7,039/ton
37	$498,371	$3,666,834	$50,409	$305,536	$803,907	82.8	$9,704/ton

[67] *See* EPA, Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993, Appendix A which has conversion equations for natural gas-fired combustion turbines.
[68] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf page 24.
[69] Note that it is not clear that this reflects the high heating value of the fuel used at Units 35-37, especially given that the heat value of the fuel used at Units 17 and 18 was tested as having a much higher heat value of 1,245 Btu/scf. However, it is the heat value listed in the 2007 Title V permit application as specific to these units, so it is used here.
[70] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf page 24.
[71] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

Table 4. Cost Effectiveness of SCR at Chaco Gas Plant Units 35, 36, and 37 Solar Mars T15000 Turbines to Reduce NOx to 15 ppmv, Using EPA's SCR Cost Calculation Spreadsheet with Urea Reagent (2018 $)

Unit	Capital Cost of SCR	Annual O&M Costs	Total Annualized Costs of SCR	NOx Removed from 2016 Baseline, tpy	Cost Effectiveness of SCR, $/ton
35	$3,666,834	$104,172	$359,298	105.2	$3,416/ton
36	$3,666,834	$103,345	$358,472	103.4	$3,468/ton
37	$3,666,834	$85,814	$340,940	73.5	$4,642/ton

As shown by a comparison of Table 4 to Table 2, the costs of SCR to achieve the same level of NOx reduction as SoLoNOx at Units 35-37 is lower than the cost of SoLoNOx. As previously stated, costs were only provided for urea-based SCR. If aqueous ammonia was used as the reagent, the costs of SCR would be lower.

Clearly, SCR alone appears to be a more cost effective method to reduce NOx emissions from Units 35-37 by 85-88% control compared to SoLoNOx. Further, SCR used in combination with SoLoNOx can achieve the greatest reductions in NOx at these units. Thus, NMED must require further evaluation of the feasibility of installing SCR at Units 35, 36, and 37, including asking Enterprise to obtain vendor analyses of the site and feasibility of SCR retrofits.

D. Units 12, 13, and 14: Clark TLA-10 2-Stroke Lean Burn RICE

Units 12, 13, and 14 are two-stroke lean-burn RICE that were constructed in 1996, each with a capacity of 3,400 hp.[72] The units each have an hourly NOx limit of 49.7 lb/hr and an annual NOx limit of 218 tpy.[73] Enterprise states in its four-factor analysis that the NOx emissions from these units are calculated from stack test data from 4/18/1995.[74] This date seems possibly incorrect, or the permit is incorrect as it identifies the units as being constructed in 1/1/1996. Enterprise further states that the maximum hourly emission rate corresponds to a NOx exhaust concentration of 1,032 ppmv.[75] That is the extent of information provided on the actual NOx emissions from these units. NMED should request more information on the units' current hours of operation and actual NOx emissions.

[72] Title V Operating Permit P116-R2M1 for Chaco Natural Gas Processing Plant at A6.
[73] *Id.* at A10.
[74] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-5.
[75] *Id.*

1. Use of Low Emission Combustion Technology

Enterprise claims that the Clark TLA-10 engines are currently operating with "Clean Burn Technology (CBT)."[76] Yet, the stated maximum hourly NOx rate of 1,032 ppmv does not reflect the levels of NOx emissions typically expected with such low emission combustion (LEC) technology. This NOx concentration is equivalent to 14 grams per horsepower-hour (g/hp-hr).[77] Note, the hourly NOx permit limits for these units of 49.7 lb/hr, corresponding to a NOx limit of 7 g/hp-hr for each 3,400 hp engine.[78] And, in fact, the information provided as part of permit applications for the source, in 2007 and in 2016, indicate that these three units were initially retrofitted with the Controlled Rapid Burn (CRB™) systems from Diesel Supply Company, guaranteeing NOx emission rates of 7 g/hp-hr.[79] But even this controlled NOx emission level does not reflect the levels of NO_x emissions achievable with LEC technology. In order to effectively evaluate a company's assessment of LEC, a more precise definition of LEC technologies and associated achievable emission rates is needed.

EPA has examined source test data from large natural gas-fired lean burn engines and has affirmed that these data support an uncontrolled emission rate from these engines, generally, of 16.8 g/hp-hr.[80] More specifically, these source test data include individual data for three Clark TLA-10 engines with uncontrolled emission rates of 16 g/hp-hr and two Clark TLA-10 engines with uncontrolled emission rates of 7 g/hp-hr.[81] Even the permitted NOx limit of 7 g/hp-hr for the engines at the Chaco Gas Plant could therefore reflect an uncontrolled emission rate, although it appears these engines were retrofit with certain combustion modifications to reduce NOx emissions by 50% (i.e., CRB™ technology to reduce NOx emissions from 14 g/hp-hr to 7 g/hp-hr). Controlled NOx emission rates with LEC are typically much lower. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable

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[76] *Id.* at 2-7.

[77] Using the following EPA conversion factors for uncontrolled lean burn engines (73 ppmv = 1 g/bhp-hr) and lean-burn engines controlled with LEC technology (73 ppmv = 1 g/bhp-hr), NOx emission rates would be 13.8 g/bhp-hr (assuming LEC control) or 14.1 g/bhp-hr (uncontrolled). *See* EPA-457/R-00-001 *Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques,* September 2000, p. 2-1, *available at*: https://nepis.epa.gov/Exe/ZyPDF.cgi/P100V343.PDF?Dockey=P100V343.PDF [hereinafter referred to as "EPA 2000 RICE Update"]. NOTE: this emission rate of 14 g/hp-hr appears to represent the uncontrolled emission rate, prior to retrofits to the units that reduced NOx emission by 50% and reflected in the permitted 49.7 lb/hr limit for these 3,400 hp engines (14 g/hp-hr * 3,400 hp / 453.6 g/lb = 100 lb/hr; 7 g/hp-hr * 3,400 hp / 453.6 g/lb = 50 lb/hr).

[78] Title V Operating Permit P116-R2M1 for Chaco Natural Gas Processing Plant at A10.

[79] *See,* Chaco Title V Renewal Permit P-116 Part 3 November 2007 *and* Chaco Permit 1555-M5 Significant Revision Application January 2016 *Emissions Support Data, Clark TLA-10 Compressor Engines, Retrofit Units 12—14*.

[80] *See* EPA Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call (October 2003) at 5, *available at:* http://www.valleyair.org/workshops/postings/2011/8-18-11-rule4702/R4702%20APPF.pdf.

[81] *Id*. at 6 and 7.

with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[82]

For reference, the following additional sources of information regarding NOx emission rates specific to Clark TLA model engines – both uncontrolled and with LEC technology – are provided here:

- EPA's 2000 RICE Update includes NOx emissions test data for specific engines, including Clark Model TLA-6, 2-stroke, lean-burn, 2,000 hp RICE retrofitted with LEC. According to EPA, six engines retrofitted by a third-party vendor had NOx emission rates ranging from 0.8–1.4 g/bhp-hr, with a mean of 1.0 g/bhp-hr.[83]

- An evaluation by a technical group for the Pipeline Research Council International looked at three of the most representative make / models of 2-stroke lean-burn compressor engines: (1) 2,250 hp Cooper GMVH-10; (2) 2,000 hp Clark TLA-6; and (3) 2,500 hp Cooper GMW-10. According to a technical report by the Ozone Transport Commission (OTC) describing this evaluation, "[t]he evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring."[84]

- In 2002, EPA collected data on emission rates of lean burn engines that have been retrofitted with LEC, including data from several state agencies for specific engine models.[85] Test results for 20 Clark TLA engines ranged from 0.4 to 2.9 g/hp-hr, with an average controlled NOx rate of 1.5 g/hp-hr.[86]

More generally, the 2012 OTC Report suggests that, "combustion related modifications have the potential to achieve from 60% to 90% reduction in NOx emissions [or, "an approximate range of NOx emissions rate of 3.0 g/bhp-hr to 0.5 b/bhp-hr"] from two-stroke lean-burn spark ignited reciprocating engines, depending upon the make/model configuration of the engine." Specifically, the 2012 OTC Report discusses the use of "layered combustion controls"

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[82] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.
[83] EPA 2000 RICE Update at 4-8.
[84] Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, p. 24, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf [hereinafter referred to as "2012 OTC Report"].
[85] *See* EPA Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call (October 2003) at 15, *available at:* http://www.valleyair.org/workshops/postings/2011/8-18-11-rule4702/R4702%20APPF.pdf
[86] *Id.* Table 4.

in order to achieve emission rates at the lower end of this range, that include: improved airflow, improved fuel-air mixing, improved ignition, and upgraded controls.[87] According to the 2012 OTC Report, the higher emission rates in this range would tend to be more representative of situations where layered combustion controls packages have not been commercialized.[88]

More recently, EPA describes layered combustion (LC) as demonstrated control techniques for 2-stroke lean-burn engines, achieving a NOx emission rate of 0.5 g/hp-hr.[89] Specifically, EPA described LC as consisting of multiple combustion modifications, including: (1) high pressure fuel injection; (2) turbocharging; (3) a precombustion chamber; and (4) cylinder head modifications.[90]

Also, recently, EPA described LEC retrofit kits designed to achieve extremely lean air-to-fuel ratios – in order to minimize NOx emissions – as encompassing the following similar retrofit technologies:

- Redesign of cylinder head and pistons to improve mixing (on smaller engines)
- Precombustion chamber (on larger engines)
- Turbocharger
- High energy ignition system
- Aftercooler
- Air-to-fuel ration controller (AFRC)[91]

It is not entirely clear what specific combustion and LEC technologies are employed for the Clark TLA-10 engines at the Chaco Gas Plant. Enterprise states that these engines are currently operating with "Clean Burn Technology" and discusses that to generally mean the use of high energy ignition system, turbocharger, and AFRC technologies.[92] The Controlled Rapid Burn (CRB™) retrofit kits originally installed on Units 12–14 appear to include pre-chambers and high

[87] *Id.*
[88] *Id.*
[89] 2016 EPA Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS (Docket ID No. EPA-HQ-OAR-2015-0500), Appendix A at 5-5, *available at:* https://19january2017snapshot.epa.gov/sites/production/files/2015-11/documents/assessment_of_non-egu_nox_emission_controls_and_appendices_a_b.pdf [hereinafter referred to as "CSAPR TSD for Non-EGU NOx Emissions Controls"].
[90] *Id.* at 5-7.
[91] EPA, Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500-0508, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance, August 2016, Appendix A at 5-3, *available at:* https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0500-0508 [hereinafter referred to as "2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls"].
[92] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-7.

flow fuel valves.[93] However, the controls at these units are not achieving NOx emission levels commensurate with LEC.

EPA noted, in its 2000 Updated Information on NOx Emissions and Control Techniques for RICE, that "CleanBurn" is a trademark of Cooper Energy Systems, and that industry comments on its draft AP-42 emission factors for stationary internal combustion engines objected to a "clean burn" designation for that reason.[94] EPA's 1997 draft AP-42 section for stationary internal combustion sources defined "clean burn" engines as separate engine families (*i.e.*, distinct from other 2-stroke and 4-stroke lean-burn engines), equipped with "LEC precombustion chamber technology" and identified the following NOx emission factors for these distinct LEC-equipped "engine families":

(1) 1.1 g/bhp-hr (2-stroke clean-burn engines); and

(2) 0.5 g/bhp-hr (4-stroke clean-burn engines).[95]

EPA's 2000 RICE Update notes that, "[t]oday, many engine manufacturers refer to their engines equipped with precombustion chambers simply as "lean-burn engines"."[96] And EPA's final AP-42 section on natural gas-fired reciprocating engines clarified the term, as follows:

> Some lean-burn engines are characterized as clean-burn engines. The term "clean-burn" technology is a registered trademark of Cooper Energy Systems and refers to engines designed to reduce NOx by operating at high air-to-fuel ratios.[97]

A recent Interstate Natural Gas Association of America (INGAA) Report provides some information on Clark TLA engine stock components and retrofit modification / upgrade options.[98] Examples from this report include: upgrading stock turbocharger and stock intercooler systems; upgrading stock low pressure direct fuel systems to high pressure fuel injection and control systems; and upgrading controls for the stock fuel system.[99] Based on the

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[93] *See* 5/12/95 Bid from Diesel Supply Company to El Paso Natural Gas Company for "converting your Clark TLA-10 engines at your CHACO plant." This bid is included in the Chaco Title V Renewal Permit P-116 Part 3 November 2007 *and* Chaco Permit 1555-M5 Significant Revision Application January 2016 *Emissions Support Data, Clark TLA-10 Compressor Engines, Retrofit Units 12—14*. *Also, see:* https://www.dieselsupply.com/.
[94] EPA 2000 RICE Update at p. 4-8.
[95] *Id. See discussion at* 3-9.
[96] *Id.* at 4-8.
[97] EPA AP-42 Chapter 3, Section 3.2 (July 2000) at 3.2-2, *available at:* https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf.
[98] INGAA, Report No. 2016-6, *Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOx Control for Natural Gas Transmission and Storage Compressor Drivers* (December 2017), *available at:* https://www.ingaa.org/File.aspx?id=33789.
[99] *Id. See, e.g.,* Table 6 at 18.

information in this report, Clark TLA model engines come equipped with a single turbo, an intercooler system, and a low pressure direct fuel system. The INGAA report evaluated controls for various regulatory scenarios that would achieve NOx emission levels in the 1–3 g/hp-hr range.[100]

LEC retrofit costs specific to Clark TLA model engines are reported in the INGAA report, ranging from $300–$600 per hp, for upgrades to the scavenging, intercooler, and fuel systems.[101] The INGAA report doesn't specify what year the cost data are from so we assume it reflects the timeframe of the report, or 2017$. Using these cost data, we can estimate the cost effectiveness of retrofitting Units 12, 13, and 14 at the Chaco Gas Plant. Retrofit costs for each 3,400 hp unit using INGAA's cost data would range from $1.02–$2.04 million, in 2017$. Using the Chemical Engineering Plant Cost Indices, these costs could increase to $1.08–$2.17 million, in 2018$.[102] It's not clear if operating costs are included in these estimates; to be conservative, annual operating costs of the LEC controls are assumed to be 15% of capital costs.[103]

The cost effectiveness of retrofitting these engines with LEC to meet a 2 g/hp-hr NOx emissions rate, based on the units' uncontrolled emission rate, is presented in the table below. The original retrofits to these units resulted in controlled NOx emission rates of 7 g/hp-hr possibly employing some of the upgrades associated with LEC. This analysis shows the cost effectiveness of an LEC retrofit that can achieve an emission level between 1–3 g/hp-hr based on current technologies and costs. The operating schedule for these engines at the Chaco Gas Plant is unknown but we present cost effectiveness for 8,000 operating hours per year since annual facility NOx emissions indicate that the units operated near capacity in 2016.[104] Note, this analysis uses an interest rate of 4.7%, reflective of current and likely near future interest rates.[105] Further note, the LEC controls are assumed to last 25 years, consistent with other cost effectiveness analyses submitted to NMED for LEC controls.[106]

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[100] *Id.* at 23.

[101] *Id.*

[102] Based on multiplying the cost estimate from the 2017 INGAA report by the ratio of the CEPCI indices for 2018 to 2017 (603.1/567.5).

[103] This assumption is consistent with cost data provided for the October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, however it results in much higher O&M costs than those used in Targa's (Eunice, Monument, and Saunders Gas Plants) and Harvest Four Corners' (Kutz Canyon Gas Plant) four-factor analyses—which ranged from $40,000/yr to $100,000/yr—and than those used for ETC Texas Pipeline's Jal No. 3 Gas Plant, which assumed O&M costs would be 13% of capital costs.

[104] *See* NMED's Emissions Analysis tool, which reports 2016 NOx emissions of 2,258.9 tons per year, compared to total annual NOx PTE for the units evaluated in Enterprise's four-factor analysis for the Chaco Gas Plant of 2,342.8 tons per year (*see* Table 1 of the November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 1-1).

[105] As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

[106] *See* 2019 Four-Factor Analyses for Roswell Compressor No. 9 and Jal No. 3..

Table 5. Cost Effectiveness of LEC at Uncontrolled Chaco Gas Plant Units 12, 13, and 14 to Reduce NO_x Levels to 2 g/hp-hr, Assuming a 4.7% Interest Rate and a 25-Year Life, 2018 $

Unit	Capital Cost of LEC to Reduce NOx from the Uncontrolled rate of 14 g/hp-hr	Annual O&M Costs (assume 15% of Capital Costs)	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (~85% NOx Reduction)	NOx Removed, tpy operating 8,000 hr/yr	Cost Effectiveness of LEC operating 8,000 hr/yr, $/ton
12	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	360	$659/ton–$1,319/ton
13	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	360	$659/ton–$1,319/ton
14	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	350	$659/ton–$1,319/ton

LEC at Units 12, 13, and 14 would be even more cost effective than what is shown if retrofits at these engines could meet even lower NOx emission levels, less than 2 g/hp-hr. Note, an analysis of individual upgrades at the units at the Chaco Gas Plant is not possible without knowing which specific LEC technologies are already employed to meet the permitted emission rate of 7 g/hp-hr and which additional possible upgrades could be installed to achieve even greater emissions reductions. NMED must ask for a list of specific LEC technologies employed at Units 12–14 and an evaluation of additional applicable LEC technologies for these units. NMED should require additional LEC retrofit techniques be evaluated in order to assess the cost effectiveness of further reducing NOx emissions from these engines to a level more in line with current LEC technology – i.e., emission levels in the 0.5–2 g/hp-hr range.

2. Use of SCR.

Enterprise did not evaluate SCR for Units 12, 13, and 14, primarily because it claimed that it was not possible to install SCR at these units due to space limitations.[107] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at Units 12, 13, and 14, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for Units 12-14

[107] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-6.

at the Chaco Gas Plant, particularly because Enterprise has not evaluated any other NOx reduction strategy for these units.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[108]

If Clean Burn or other low emissions technology is not a viable or cost-effective control for lean burn engines, SCR could possibly be a more cost-effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[109] In Section XX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[110] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

II. DCP Midstream – Eunice Gas Plant

The DCP Midstream Eunice Gas Plant is a natural gas processing plant located in Lea County, New Mexico. A NMED Statement of Basis for the plant's Title V permit describes the plant as follows: "The Eunice plant consists of an Inlet Receiving System, Amine Treater, Sulfur Recovery Plant, Inlet Compression, Dehydration, Cryogenic/Turbo Expansion Plant with External Propane Refrigeration, and product sales for Residue Gas, NGLs, and Condensate. Supporting systems and operations at the plant include Fuel Gas Systems, Instrument and Starting Air Systems, a Heat Medium (Hot Oil) System, Cooling Towers, Process Flare, Acid Gas Flare, and Drain Systems. Processing operations at the plant include chemical reaction processes, thermodynamic processes, and physical processes."[111] The plant separates heavier hydrocarbons that can be condensed into liquids (called "Natural gas liquids or NGLs" and removes impurities from the natural gas such as water, hydrogen sulfide (H2S) gas, and carbon dioxide gas.[112]

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[108] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.

[109] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.

[110] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[111] NMED Statement of Basis – Narrative, Title V Permit, for Permit Nos. 0044-M-10-M10R6 and P086-R3, at 1.

[112] *Id.*

According to the permit, the plant includes several four-stroke lean-burn RICE, several natural gas-fired turbines, boilers, a heater, gas sweetening equipment (amine unit, sulfur recovery unit (SRU) incinerator, acid gas and SRU flares), and other emission units.[113] In DCP Midstream's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Solar Centaur Turbines: Units 17A, 18B, 19A, 25A, and 26A
- Amine Unit controlled by SRU Incinerator: Unit 31
- Startup, Shutdown, Malfunction (SSM).[114]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[115] The following provides a review of the company's four-factor analyses for the turbines. The analysis for the amine unit and SSM emissions is addressed in Section XXIII. below.

A. Interest Rate Used in Cost Analyses.

DCP Midstream used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[116] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[117] The current bank prime rate is 3.25%.[118] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[119] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[120] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable

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[113] Title V Operating Permit P086-R3 for DCP Eunice Gas Plant at A6 to A8.
[114] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Eunice Gas Plant at 1-2.
[115] *Id.*
[116] *Id.* at Section 8.0 Supporting Documentation.
[117] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[118] https://www.federalreserve.gov/releases/h15/.
[119] https://fred.stlouisfed.org/series/DPRIME.
[120] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

B. Solar Centaur Natural Gas-Fired Combustion Turbines (Units 17A, 18B, 19A, 25A, and 26A).

The combustion turbines evaluated at the Eunice Gas Plant are Solar combustion turbines, model T-4002 of 3329 hp capacity (Units 17A, 25A, and 26A) and model T-4502 (Units 18B and 19A) of 3372 hp capacity.[121] These units were constructed between 1974 and 1986.[122] Units 18A and 19A are subject to a NOx emission limit of 165.85 ppmv at 15% O_2 and Units 25A and 26A are subject to a NOx limit of 158.76 ppmv at 15% O_2, pursuant to 40 C.F.R. Part 60, Subpart GG.[123] Under the terms of the permit, the units are also subject to the following hourly and annual emission limits of NOx.

Table 6. Limits from DCP Midstream Title V Permit for the Eunice Gas Plant Combustion Turbines[124]

Combustion Turbine Unit ID	NOx limit, lb/hr	NOx limit, tpy
17A	18.5	81.0
18B	23.0	100.9
19A	23.0	100.9
25A	18.5	81
26A	18.5	81

DCP Midstream evaluated two control options for these combustion turbines: Solar's SoLoNOx combustion system and SCR.

1. Baseline Emissions for Units 17A, 18B, 19A, 25A, and 26A.

DCP Midstream did not provide any specific data on actual emissions for the Solar Centaur combustion turbines in its four-factor analysis of controls. The company did state that its cost effectiveness analyses for SoLoNOx and SCR were based on 2016 turbine operating hours multiplied by the permitted potential to emit rate (lb/hr).[125] However, the company did not provide the operating hours or this calculation of 2016 emissions in its four-factor analysis. The company also provided analyses of cost effectiveness of controls "[u]sing the actual emissions testing data (NSPS KKKK) for these turbines, rather than [potential to emit]."[126] Yet, the company provided no data in its four-factor analyses as to what the actual emission testing results were. Further confusing the matter is that, based on a review of the permit, the turbines are not subject to NSPS KKKK. Instead, all of the units except Unit 17A are subject to

[121] Title V Operating Permit P086-R3 for DCP Eunice Gas Plant at A6 to A7.
[122] *Id.*
[123] *Id.* at A10.
[124] *Id.* at A9.
[125] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Eunice Gas Plant at 3-10, fn 13.
[126] *Id.*

NSPS Subpart GG, and the Title V permit does not identify Unit 17A as subject to either NSPS Subpart GG or Subpart KKKK.[127] A review of Title V permit application data for the Eunice Gas Plant on the NMED's Emissions Analysis Tool did not find any other emissions testing data available for these units.[128]

NMED must make available whatever test data is being relied on to reflect actual emissions of these five combustion turbines if NMED intends to rely on the cost effectiveness analyses provided in a footnote of DCP Midstream's four-factor analysis. NMED should present information on the test data so the circumstances of the stack tests can be reviewed. According to DCP Midstream's four-factor analysis, its 2016 emission inventory is based on its actual operating hours multiplied by its hourly NOx emission limit.[129] Given that this is how DCP Midstream reports actual emissions for the combustion turbines to NMED and in the absence of testing documentation to ensure that the test data DCP relies on for its alternative baseline analysis reflects actual emissions at all levels of operation of the combustion turbines, it seems most appropriate to use the data that DCP has been using for its emission inventory. NMED should require that DCP identify the operating hours of each unit that it has assumed for the combustion turbines.

2. Evaluation of SoLoNOx for Turbines at Units 17A, 18B, 19A, 25A, and 26A.

DCP Midstream states that SoLoNOx can achieve an "overall reduction efficiency of 70-80%...for the turbines located at this facility using this technology in comparison to permitted [potential to emit]."[130] NMED should request that DCP Midstream identify the NOx rate that Solar Turbines guarantees for each of the five turbines at Eunice Gas Plant. Specifying a NOx emission rate that can be met with SoLoNOx also would provide for a clear benchmark for comparison to SCR.

Based on assuming 70 to 80% reduction with SoLoNOx from the permitted ppmv NOx emission limits, it appears that DCP Midstream evaluated SoLoNOx to achieve NOx emission rates in the range of 31 ppmv to 50 pppmv at 15% O_2 at Units 17A, 18B, 19A, 25A, and 26A.[131] These seem like high emission rates expected with SoLoNOx, based on a review of emission limit data for combustion turbines in the EPA's RACT/BACT/LAER Clearinghouse which indicates SoLoNOx limits in the range of 15-25 ppmv. As another comparison, Enterprise evaluated SoLoNOx for the Solar Mars turbines at the Chaco Gas Plant and stated that SoLoNOx could reduce NOx concentrations down to 15 ppmv. Although Section 8.0 of DCP Midstream's four-factor analysis

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[127] Title V Operating Permit P086-R3 for DCP Eunice Gas Plant at A5, Table 103.A.

[128] While Section 8.0 of the four-factor analysis for the Eunice Gas Plant has specific baseline NOx emission rates for the Linam Ranch Gas Plant combustion turbines, it does not have baseline NOx rates for the Eunice Gas Plant combustion turbines.

[129] *Id.* at 3-11.

[130] *Id.* at 2-4.

[131] This range of controlled ppmv NOx emission rates is based on assuming 70 to 80% reduction from the 158.76 ppmv NOx emission limit that Units 17A, 25A, and 26A and from the 165.85 ppmv NOx limit that Units 18B and 19A are subject to.

has cost data sheets for SoLoNOx indicating a NOx guarantee from Solar of 15 ppm, those cost data sheets pertain to the Linam Ranch Gas Plant rather than for the combustion turbines at the Eunice Gas Plant. For these reasons as well as completeness of the four-factor analysis of emissions controls for these units, NMED must collect more specific information on the NOx emission rates that DCP Midstream used in its SoLoNOx cost effectiveness analysis for the combustion turbines.

In terms of the life of SoLoNOx controls in the cost effectiveness analyses, DCP's analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[132] In the table below, we revised DCP Midstream's cost effectiveness analyses of SoLoNOx to take into account a longer lifetime of controls and a lower 4.7% interest rate.

Table 7. Revised Cost Effectiveness of SoLoNOx at Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant

Unit	DCP's Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	DCP's Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25-Year Life
17A	$264,731	$4,909/ton	$244,277	$4,530/ton
18B	$264,154	$3,578/ton	$243,700	$3,301/ton
19A	$264,154	$3,618/ton	$243,700	$3,338/ton
25A	$264,731	$5,186/ton	$244,277	$4,785/ton
26A	$264,731	$6,005/ton	$244,277	$5,542/ton

Thus, the cost effectiveness of SoLoNOx at Units 17A, 18B, 19A, 25A, and 26A are in the range of $3,300/ton to $5,542/ton to achieve 70-80% NOx reduction. However, if SoLoNOx can achieve 15-25 ppmv NOx emission rates at these units as has been permitted for other Solar turbine units with SoLoNOx, and as has been proposed in several four-factor analyses before NMED, then the NOx removal expected with SoLoNOx would be 84 to 91% and the controls would be even more cost effective than shown in the above table. The table below provides an estimate of the cost effectiveness of SoLoNOx if the controls could achieve 25 ppmv (~85% control) and 15 ppmv (~90% control).

[132] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

Table 8. Estimated Cost Effectiveness of SoLoNOx at Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant to Meet 25 ppmv NOx Rates and to Meet 15 ppmv NOx Rates.

Unit	Revised Total Annual Costs of SoLoNOx	Estimated NOx Reduced to Achieve 25 ppmv NOx Rate (~85% Reduction), tpy	Estimated NOx Reduced to Achieve 55 ppmv NOx Rate (~90% Reduction), tpy	Cost Effectiveness to Meet 15 to 25 ppmv NOx limit, $/ton
17A	$244,277	68.8	72.9	$3,352 - $3,549/ton
18B	$243,700	85.7	90.8	$2,684 - $2,842/ton
19A	$243,700	84.8	89.8	$2,714 - $2,874/ton
25A	$244,277	65.2	69.0	$3,541 - $3,749/ton
26A	$244,277	56.3	59.6	$4,100 - $4,341/ton

If SoLoNOx at Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant could meet more typical NOx limits with SoLoNOx of 15-25 ppmv, then the SoLoNOx controls would be even more cost effective than shown in DCP Midstream's four-factor analysis.

3. Evaluation of SCR for Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant.

Unlike Enterprise in its four-factor analysis of controls for the combustion turbines at the Chaco Gas Plant, DCP Midstream evaluated SCR as a technically feasible control option for the Solar Centaur gas combustion turbines of Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant. DCP Midstream used EPA's SCR cost spreadsheet made available with EPA's Control Cost Manual.[133] While the company presented printouts of the EPA SCR cost spreadsheet in Section 8.0 of its four-factor analysis, the printouts appear to be for the Linam Ranch Gas Plant and not the Eunice Gas Plant. NMED should request a printout of the pages of the SCR cost spreadsheet for Units 17A, 18B, 19A, 25A, and 26A of the Eunice Gas Plant so the inputs to the spreadsheet can be reviewed.

DCP Midstream only assumed 70% control could be achieved with SCR at Units 17A, 18B, 19A, 25A, and 26A, even though the company indicated that SCR could achieve up to 90% control.[134] As presented NPCA's Oil and Gas Four-Factor Report, NESCAUM assumed 90% control with SCR in its 2000 Status Report to control small gas turbines down to 15 ppmv.[135] Analyses of EPA's SCR cost spreadsheet for combustion turbines of similar size to Units 17A, 18B, 19A, 25A, and 26A shows that the spreadsheet's calculation of capital cost does not vary based on the NOx control efficiency assumed for the SCR, but that the direct operational expenses increase by

[133] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Eunice Gas Plant at 3-11.
[134] *Id.* at 2-6.
[135] NPCA March 2020 Oil and Gas Four-Factor Report at 74-75. *See also* NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15), available at http://www.nescaum.org/documents/nox-2000.pdf/view.

about 17.7%. Using this assumption, we revised DCP Midstream's SCR cost estimate to reflect the costs to achieve 90% NOx reduction, reflective of approximately a 15 ppmv NOx emission rate, along with using a longer life of the SCR of 25-years[136] and a 4.7% interest rate (instead of DCP's assumed 20-year life of SCR and 5.5% interest rate). The table below provides an estimated cost effectiveness of SCR to achieve 90% control at Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant.

Table 9. Estimated Cost Effectiveness of SCR to Achieve 90% Reduction (~15 ppmv NOx Rate) at Units 17A, 18B, 19A, 25A, and 26A (at 4.7% interest rate and 25-year life)

Eunice Gas Plant Unit #	DCP's Capital Cost of SCR	DCP's Annual Operational Costs of SCR[137]	Estimate of Revised DCP Annual Operational Costs of SCR to Reflect 90% Control[138]	Revised Annual Cost of SCR to Achieve 90% Control	NOx Emission Reductions at 90% Control, tpy	Cost Effectiveness of SCR to Achieve 90% Control
17A	$1,500,000	$149,435	$136,663	$239,914	72.87	$3,292/ton
18B	$1,500,000	$148,858	$138,195	$241,446	90.78	$2,660/ton
19A	$1,500,000	$148,858	$137,979	$241,230	89.79	$2,686/ton
25A	$1,500,000	$149,435	$135,696	$238,947	68.99	$3,463/ton
26A	$1,500,000	$149,435	$123,938	$227,189	59.58	$3,813/ton

A comparison of Table 9 to Tables 7 and 8 above shows that SCR at the Eunice Gas Plant Units 17A, 18B, 19A, 25A, and 26A is actually more cost effective than SoLoNOx at DCP's assumed 70-80% control or even assuming SoLoNOx can achieve 15 ppmv. SCR could be even more cost effective if there are opportunities to share an SCR between two or more combustion turbines. Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[139] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15%

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[136] EPA's Control Cost Manual indicates that SCR at industrial units has a life of 25-years. *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

[137] This was calculated from DCP Midstream's Total Annual Cost of SCR by subtracting the product of DCP's capital cost of SCR and a cost recovery factor reflective of DCP's assumed 5.5% interest rate and 20-year life.

[138] Estimated by multiplying DCP's annual operational costs of SCR by a factor of 1.177.

[139] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.

oxygen.[140] NMED should require DCP Midstream to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

III. IACX Roswell – Bitter Lake Compressor Station

The IACX Roswell, LLC Bitter Lake Compressor Station is located 13 miles northeast of Roswell, New Mexico and identified by NMED as contributing to regional haze at the Salt Creek WA Class I area.[141] NMED has described the facility processes as follows:

> The function of the facility is to compress and dehydrate field natural gas for transport in underground pipelines, to extract natural gas liquids, and to recover helium.[142]

According to the permit, the plant includes two Cooper-Bessemer 2-stroke lean-burn RICE, a glycol dehydrator with two associated reboilers, a refrigeration unit, and three tanks.[143] In IACX's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Cooper-Bessemer 2SLB RICE GMVH-10C: Units C-891 and C-893.[144]

The selection of these two engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[145] The following provides a review of the company's four-factor analyses.

A. Units C-891 and C-893: Cooper-Bessemer GMVH-10C 2-Stroke Lean Burn RICE

Units C-891 and C-893 are two-stroke lean-burn RICE that were constructed in the 1980s, each with a capacity of 2,250 hp.[146] The units each have an hourly NOx limit of 20 lb/hr and an annual NOx limit of 87.6 tpy.[147] That is the extent of information provided on the actual NOx emissions from these units. NMED should request more information on the units' current hours of operation and actual NOx emissions.

[140] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.
[141] November 2019 Regional Haze Four-Factor Analysis for IACX Roswell, LLC Bitter Lake Compressor Station at 3.
[142] Title V Operating Permit P047-R3 for Bitter Lake Compressor Station at A4.
[143] Title V Operating Permit P047-R3 for Bitter Lake Compressor Station at A6–A7.
[144] November 2019 Regional Haze Four-Factor Analysis for IACX Roswell, LLC Bitter Lake Compressor Station at 4.
[145] *Id.*
[146] Title V Operating Permit P047-R3 for Bitter Lake Compressor Station at A7.
[147] *Id.* at A8.

1. Use of Low Emission Combustion Technology

IACX claims that the Cooper-Bessemer GMVH-10C engines are currently operating with turbochargers and efficient combustion air intercoolers and describes these as "Clean Burn Technology (CBT)."[148] And IACX states that, "[b]ased on manufacturer guidance, the addition of these clean burn technologies allows the engines to range from 1.74 to 3.04 g/hp-hr, which allows for 25% to 57% reduction in NOx emissions; thus, no further assessment of these control practices is included in this report."[149] Yet, the permitted maximum hourly NOx emission rate of 20 lb/hr does not reflect the levels of NOx emissions claimed by IACX in its four-factor analysis. This hourly NOx emission rate is equivalent to 4 g/hp-hr for a 2,250 hp engine. A recent permit application supplied an uncontrolled NOx emission rate of 4 g/hp-hr, based on "engine manufacturer data."[150] This NOx emission level does not reflect the levels of NOx emissions achievable with LEC technology. In order to effectively evaluate a company's assessment of LEC a more precise definition of LEC technologies, and associated achievable emission rates, is needed.

NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).

For reference, the following additional sources of information regarding NOx emission rates specific to Cooper-Bessemer GMV model engines – both uncontrolled and with LEC technology – are provided here:

- EPA's 2000 RICE Update includes NOx emissions test data for specific engines, including Cooper-Bessemer GMV-10C, 2-stroke, lean-burn, 1,100 hp RICE retrofitted with LEC. Tested at 0.61 g/bhp-hr.[151]

- An evaluation by a technical group for the Pipeline Research Council International looked at three of the most representative make / models of 2-stroke lean-burn compressor engines: (1) 2,250 hp Cooper GMVH-10; (2) 2,000 hp Clark TLA-6; and (3) 2,500 hp Cooper GMW-10. According to a technical report by the OTC describing this evaluation, "[t]he evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring."[152]

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[148] November 2019 Regional Haze Four-Factor Analysis for IACX Roswell, LLC Bitter Lake Compressor Station at 7.
[149] *Id.*
[150] Bitter Lake Compressor Station permit application P047R3 (8/17/2016) Section 6, Page 2.
[151] EPA 2000 RICE Update at 4-8.
[152] Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, p. 24, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf [hereinafter referred to as "2012 OTC Report"].

EPA describes LEC retrofit kits designed to achieve extremely lean air-to-fuel ratios – in order to minimize NOx emissions – as encompassing the following retrofit technologies:

- Redesign of cylinder head and pistons to improve mixing (on smaller engines)
- Precombustion chamber (on larger engines)
- Turbocharger
- High energy ignition system
- Aftercooler
- Air-to-fuel ration controller (AFRC)[153]

So, in addition to the turbochargers and upgraded intercooler systems already employed at these Cooper-Bessemer engines, NMED should request that the company evaluate the cost effectiveness of retrofitting these engines with additional LEC technologies – e.g., precombustion chambers, high energy ignition systems, AFRCs, etc. – to further reduce NOx emissions from these engines– e.g., to achieve emission levels as low as 0.5 g/hp-hr. Without data on actual NOx emissions from these engines it's not possible to know if, in fact, the current "clean burn technologies" employed at these units are achieving the emission levels of 1.74 to 3.04 g/hp-hr (that are based on manufacturer guidance) identified in the company's four-factor analysis. NMED should ask for test data reflective of actual operations at maximum operating capacity and ensure that these emission rates are a reasonable projection of NOx emissions in 2028.

2. Use of SCR

IACX did not evaluate SCR for Units C-891 and C-893, primarily because it claimed that the two engines run on ongoing variable loads and an SCR system may not function effectively at variable loads.[154] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly if it could achieve greater NOx emissions reductions from these units cost effectively.

[153] EPA, Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500-0508, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance, August 2016, Appendix A at 5-3, *available at:* https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0500-0508 [hereinafter referred to as "2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls"].

November 2019 Regional Haze Four-Factor Analysis for IACX Roswell, LLC Bitter Lake Compressor Station at 7.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[155]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[156] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[157] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

IV. Targa Eunice Gas Processing Plant

The Targa Midstream Services, LLC Eunice Gas Plant is a natural gas processing plant identified by NMED as potentially contributing to regional haze at the Carlsbad Caverns National Park Class I area.[158] NMED has described the facility processes as follows:

> The function of the facility is to receive field natural gas, perform dehydration and removal of carbon dioxide and hydrogen sulfide, and separate natural gas liquids (NGL). The products (natural gas and NGL) are compressed or pumped to sales pipelines for distribution.[159]

According to the permit, the plant includes 21 reciprocating internal combustion engines (RICE), two boilers, an amine still, three electric compressors, backup diesel generators, flares, glycol dehydrator sources, heaters, and storage tanks.[160] In Targa's four-factor submittal, the company evaluated air pollution controls for the following emission units:

- Clark 2SLB RICE BA-8: Units C-01, C-02, C-03, C-04, C-05, C-06, C-07, C-09

[155] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[156] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[157] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[158] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 1-1.
[159] Title V Operating Permit P109-R3 for Eunice Gas Processing Plant at A3.
[160] *Id.* at A7-A9.

- Clark 2SLB RICE HBA-8: Units C-10, C-11, C-12
- Clark 2SLB RICE HBA-T8: Unit C-13
- Wickes/Type A Boiler: Units B-01, B-02.[161]

The selection of these sources for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hr or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[162] The following provides a review of the company's four-factor analyses.

A. Units C-01 through C-07, C-09 through C-13: Clark Natural Gas-Fired 2-Stroke Lean-Burn RICE

Units C-01 through C-07 and C-09 are Clark BA-8 two-stroke lean-burn RICE that were constructed in 1984, each with a capacity of 1,200 hp.[163] Units C-01 through C-07 each have an hourly NOx limit of 53.6 lb/hr and an annual NOx limit of 234.8 tpy.[164] Unit C-09 is restricted to 500 hours per year operation and has an hourly NOx limit of 53.6 lb/hr and an annual NOx limit of 13.4 tpy.[165]

Units C-10 through C-12 are Clark HBA-8 two-stroke lean-burn RICE that were constructed in 1984, each with a capacity of 1,600 hp.[166] The units each have an hourly NOx limit of 77.2 lb/hr and an annual NOx limit of 19.3 tpy.[167] These units are restricted to 500 hr/yr operation.[168] Unit C-13 is a Clark HBA-T-8 two-stroke lean-burn RICE that was constructed in 1984, with a capacity of 2,050 hp.[169] This unit has an hourly NOx limit of 61.1 lb/hr and an annual NOx limit of 267.5 tpy.[170]

1. Evaluation of Baseline NOx Emissions

Targa's four-factor submittal includes unit-specific operating hours based on 2016 emission inventory calculations or based on permit limits of 500 hr/yr for some units (C-09 through C-12). Uncontrolled NOx emission rates (g/hp-hr) in Targa's original four-factor analysis are, for all but one unit, based on a single performance test conducted in July 2015. The NOx emission rate for the one unit without performance test data, Unit C-03, is noted as, "from client."[171] Targa's February 2020 Addendum includes a corrected uncontrolled NO_x emission rate for C-03,

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161 November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 2-7.
162 *Id.* at 1-3.
163 Title V Operating Permit P109-R3 for Eunice Gas Processing Plant at A7.
164 *Id.* at A10.
165 *Id.* and NSR Permits 067-M8R1.
166 Title V Operating Permit P109-R3 for Eunice Gas Processing Plant at A7.
167 *Id.* at A10.
168 *Id*. at A12 and NSR Permits 067-M8R1 and 067-M7.
169 Title V Operating Permit P109-R3 for Eunice Gas Processing Plant at A7.
170 *Id.* at A11.
171 November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant. *See, e.g.,* Appendix B Unit C-03.

based on a 2015 performance test, of 14.192 g/hp-hr.[172] The actual emission rates for these units, based on the July 2015 testing, and the allowable NOx emission rates are shown in the table below.[173]

Table 10. Targa Eunice Gas Processing Plant 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Actual Emissions from April 2015 Test Data [g/hp-hr]
C-01	1,200	53.6	20.3	13.165
C-02	1,200	53.6	20.3	9.226
C-03	1,200	53.6	20.3	14.192
C-04	1,200	53.6	20.3	11.742
C-05	1,200	53.6	20.3	9.285
C-06	1,200	53.6	20.3	13.261
C-07	1,200	53.6	20.3	13.787
C-09	1,200	53.6	20.3	17.249
C-10	1,600	77.2	21.9	11.401
C-11	1,600	77.2	21.9	16.265
C-12	1,600	77.2	21.9	9.838
C-13	2,050	61.1	13.5	13.654

As shown, the actual emission rates for most of these units—with the exception of unit C-13—are lower than these units' allowable NOx emission rates, with some less than 50% of allowable levels. So, either the 2015 performance test data was not conducted while the engines were operating at maximum capacity or the allowable NOx emission rates have been set unreasonably high. NMED should present information on the 2015 test data so the circumstances of the tests can be reviewed. Targa's February 2020 Addendum included the results from portable

analyzer testing conducted over a few days in August 2016 for the engines at the Saunders Gas Plant, which presumably are the tests used in determining baseline emissions for the four-factor analysis for that source.[174] NMED and Targa should review performance tests based on EPA Reference Methods for the Eunice Gas Plant to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. Citing variability in test data, Targa admits that these data are only a snapshot in time and only provide potential emissions based on that snapshot.[175] If testing is only done sporadically and is not done using EPA Reference Methods then it is questionable that such test data truly

[172] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 7.
[173] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant Appendix B.
[174] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 18-62.
[175] *Id.* at pdf page 6.

reflect an accurate projection of emissions expected over the lifetime of the controls being evaluated.

According to the source's Title V permit application, the allowable NOx emissions for these units are based on performance test data. Specifically, in the April 2018 Title V renewal application for the Eunice Gas Processing Plant, permitted rates for units C-01 through C-07 and C-09 of 53.6 lb/hr (equivalent to 20 g/hp-hr) are based on "stack data."[176] Note, stack test-based emissions are included for units C-09 through C-11, which are from the 2008 Title V renewal application, and are more in line with the emission rates used in the four-factor analysis (i.e., the Title V application lists "stack test-based emissions" for unit C-09 of 44.6 lb/hr (16.9 g/hp-hr) and for units C-10 and C-11 of 60 lb/hr (17.0 g/hp-hr), compared to the emission rates in the four-factor analysis of 17.249, 11.401, and 16.265 g/hp-hr for units C-09, C-10, and C-11, respectively).[177] However, the "current permitted rates (based on stack data)" for Units C-01 through C-07 that are listed in Targa's 2018 Title V permit application are equivalent to 20 g/hp-hr and are significantly higher than the NOx emission rates that the company's four-factor cost effectiveness analysis is based upon, meaning NOx reductions estimates for the various control options considered may be underestimated. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on a more comprehensive estimate of emissions expected in 2028.

2. Use of Low Emission Combustion Technology

Targa describes the LEC control technologies for these 2SLB engines as "Clean Burn Technology (CBT)."[178] Targa determined that this LEC technology is a technically feasible option for the 2SLB RICE units at the Eunice Gas Plant and the cost analysis provided in its four-factor analysis indicates this control is cost effective, especially for the engines that operate without restriction (i.e., Units C-01 through C-07 and C-13). Despite this, Targa concludes these retrofits would be uneconomical.[179]

The cost analysis in Targa's four-factor submittal doesn't support this claim, and the cost effectiveness of controls may be even more favorable than what is presented by Targa.

In its original November 2019 submittal, Targa presents cost effectiveness of controls for units C-01 through C-07 and for unit C-13 that range from $900–$6,000 per ton. The capital cost estimates are based on "manufacturer specification" and the annual operating and maintenance costs were provided by Targa.[180] Note, these annual operating and maintenance costs are higher than what was provided by other companies for LEC retrofits for similar

[176] *See* April 2018 Title V Permit Application for Eunice Gas Processing Plant at pdf page 50.
[177] *Id.* at 47 and 48.
[178] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 2-9.
[179] *Id.* at 7-1.
[180] *Id.* Appendix B. Note, Targa stated, on pdf page 8 of its February 2020 Addendum, that "the O&M cost included in the analyses were based on Targa's experience operating similar control devices at other sites for expected maintenance and repair."

engines.[181] Targa's February 2020 Addendum included a revised control cost analysis, with costs effectiveness ranging from $3,331–$121,892 per ton, based on much higher cost estimates, and based on higher controlled NOx emission rates.[182] The capital investment for the Clean Burn Technology in the original submittal totaled just under $1 million per engine, compared to over $5 million in the Addendum.[183] The original capital cost estimates are in line with other capital cost estimates for LEC controls at other similar engines, at less than $140/hp,[184] whereas the capital cost estimates in Targa's Addendum are significantly higher, at up to $400/hp. It appears that the revised costs include $3 million—per engine—for electrical power, which Targa indicated in its original submittal could cost between $1–$3 million but would require an engineering assessment in order to know the full cost of this upgrade.[185] Note, even without these electrical upgrades, the other capital costs reach over $200/hp which is still significantly higher than the Targa's original estimates of less than $140/hp.

In its original submittal Targa stated that the Clean Burn Technology upgrades would either include turbochargers or externally driven blowers, with the electrical upgrades only necessary if blowers are used.[186] Even assuming the need for blowers and the highest cost estimate for upgrading the electrical substation (i.e., $3 million instead of $1 million), the cost effectiveness of these LEC controls is as low as $3,300—$5,600/ton for frequently-operating engines.[187] Assuming the electrical upgrades would cost $1 million instead of $3 million or that electrical upgrades aren't needed would obviously result in much more favorable cost effectiveness of these controls.

Note that Targa's submittal for the Saunders Gas Plant includes an analysis of the exact same LEC controls for the 2SLB RICE at that facility—e.g., requiring turbochargers or externally driven blowers—and the capital costs for that analysis are in line with the original cost estimates for the Eunice Gas Plant, at <$140/hp. And Targa's February 2020 Addendum for the Eunice, Monument, and Saunders gas plants did not include higher cost estimates for increased electricity needs at the Saunders Gas Plant. It's true that there are on-site electrical generation capabilities at the Saunders Gas Plant (e.g., units G-01 through G-04) but Targa's analysis for this facility does not appear to reflect a measurable increase in capital cost expenditures

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[181] *See, e.g.,* November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant, which assumed O&M costs of $40,000/yr for Clark HRA-8 engines.

[182] *See* February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 7 and 83—95.

[183] Note, these original capital cost estimates are in line with other company analyses for similar engines, e.g., Harvest Four Corners Kutz Canyon Gas Processing Plant's analysis for Clark HBA-8 engines used capital cost estimates of $1,000,000. Also, EPA's 2000 RICE Update (p. 5-2) included capital cost estimates for third-party retrofit of a Clark Model HSRA, 2SLB 1,000 hp 8-cylindar engine at a pipeline station of $710,000.

[184] *See, e.g.*, November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant cost data for Clark engines at just under $140/hp.

[185] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 2-10 and 3-2.

[186] *Id.*

[187] E.g., cost effectiveness of C-13 at 7,560 hr/yr is $3,331/ton, C-06 at 8,123 hr/yr is $5,465/ton, C-03 at 7,275 hr/yr is $5,430/ton, C-01 at 8,009 hr/yr is $5,600/ton.

associated with the externally driven blowers that may be required at this site for LEC controls at the 2SLB RICE. And at any rate, any cost analysis associated with upgrades to a power substation that serves the Eunice Gas Plant should be considered separately, as part of a facility-wide assessment of the cost effectiveness of electrifying additional sources that could further reduce NOx emissions from the plant (e.g., electrification of additional engines).

In Targa's original submittal, its cost effectiveness analysis assumes controlled NOx emission rates of 2 g/hp-hr based on "information provided by the engine control vendor."[188] The corresponding NOx emissions reductions in Targa's original four-factor analysis for these units range from 61% to 88%.[189] Note, greater emissions reductions would result from control of units that are operating at levels closer to permitted levels (which are, again, based on test data for the units according to the source's Title V permit application) would mean that the LEC controls would be even more cost effective than what is shown in the original four-factor analysis. Targa specifically describes the control technology for these engines as able to reduce NOx emissions between 70% and 90%.[190] Subsequently, Targa's Addendum includes a new analysis of the cost effectiveness of reducing NOx emissions to levels of 4 g/hp-hr and 5 g/hp-hr, reflecting NOx emissions reductions of only 46–77%.[191]

In addition, as a result of assuming what could be unreasonably low NOx emission rates for current uncontrolled emissions from some of the 2SLB engines, i.e., emission rates based on performance test data that show much lower rates than the permitted limits for these units (that, according to Targa's Title V permit application, are based on stack data),[192] Targa then also potentially further underestimates the magnitude of potential NOx reductions for these units in its cost effectiveness analysis. The permitted hourly NOx emission rates, based on stack test data, are as follows: 20 g/hp-hr (units C-01 through C-07 and C-09); 23 g/hp-hr (units C-10 through C-12); and 14 g/hp-hr (unit C-13).[193] The permitted rate for unit C-13 is in line with the performance test data from 2015 used in the four-factor analysis but the other units' emission rates are significantly lower in the four-factor analysis than the stack test based rates in the source's Title V permit application. Therefore, the potential emissions reductions achieved by retrofitting units C-01 through C-07 and C-09 through C-12 could be much greater than what the four-factor analysis shows for these units. For uncontrolled permitted emission rates around 20 g/hp-hr, controlled rates of 2 g/hp-hr would achieve 90% reduction in NOx emissions.

[188] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 3-3.
[189] *Id.* at Appendix B.
[190] *Id.*at 2-9.
[191] *See* February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 83—95.
[192] *See* April 2018 Title V Permit Application for Eunice Gas Processing Plant at pdf page 50.
[193] *Id.* at pdf pages 48-51.

With respect to the life assumed for LEC control, Targa assumed a 20-year period.[194] Targa appears to base this on EPA's guidance default for SCR.[195] It's possible that LEC controls can last 25 years, as stated in other cost effectiveness analyses submitted to NMED for LEC controls.[196]
Also, Targa uses an interest rate of 5.5% which is likely high and therefore underestimates annualized costs of control for these engines. As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

Revising Targa's cost effectiveness analyses to address some of these issues, including assuming: 1) a 4.7% interest rate (instead of 5.5%), 2) a 25-year life of LEC (instead of an assumed 20-year life), and 3) emissions reductions of 90% based on potential operation at permitted levels (based on stack test data), improves the cost effectiveness of these controls even further, as shown in the table below. Note, this revised analysis uses Targa's original capital investment costs, since these are more in line with the cost analysis for its Saunders Gas Plant and with other capital cost estimates for LEC technology for similar engines; additional capital investments related to electrical capacity upgrades at the facility should be assessed, in more detail, as a separate broader analysis. Further note, this revised analysis assumes a slightly lower NOx emissions reductions estimate for unit C-13 of 85%, based on this unit's actual emission rate, since this emission rate is in line with permitted emissions for this unit.

[194] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant Appendix B.
[195] *Id.*
[196] *See* 2019 Four-Factor Analyses for Roswell Compressor No. 9 and Jal No. 3.

Table 11. Cost Effectiveness of LEC at Uncontrolled Eunice Gas Plant Units C-01 through C-07 and C-09 through C-13 to Reduce NO_x Levels to 2 g/hp-hr, Assuming 90% Reductions in NOx Emissions, at 4.7% Interest Rate, and a 25-Year Life of Controls, 2019 $

Unit	Size [hp]	Capital Cost of LEC to Reduce NOx from the Uncontrolled rate of 20 g/hp-hr	Annual O&M Costs	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (90% NOx Reduction)	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC, $/ton
C-01	1,200	$950,000	$100,000	$165,392	8,009	191	$867/ton
C-02	1,200	$950,000	$100,000	$165,392	4,271	102	$1,626/ton
C-03	1,200	$950,000	$100,000	$165,392	7,275	173	$955/ton
C-04	1,200	$950,000	$100,000	$165,392	5,996	143	$1,159/ton
C-05	1,200	$950,000	$100,000	$165,392	7,684	183	$904/ton
C-06	1,200	$950,000	$100,000	$165,392	8,123	193	$855/ton
C-07	1,200	$950,000	$100,000	$165,392	6,476	154	$1,073/ton
C-09	1,200	$950,000	$100,000	$165,392	500*	12	$13,893/ton
C-10	1,600	$950,000	$100,000	$165,392	500*	16	$10,420/ton
C-11	1,600	$950,000	$100,000	$165,392	500*	16	$10,420/ton
C-12	1,600	$950,000	$100,000	$165,392	500*	16	$10,420/ton
C-13	2,050	$950,000	$100,000	$165,392	7,560	203**	$814/ton

* These units are limited to 500 hr/yr operation in NSR Permits 067-M8R1 and 067-M7.
** Emissions reductions for Unit C-13 are based on controlling NOx emissions from the unit's actual emission rate of 14 g/hp-hr to 2 g/hp-hr (i.e., assuming NOx emissions reductions of 85%, instead of the 90% reduction assumed for all other units).

In Targa's original submittal it specifically describes the LEC modifications for these engines as including pre-combustion chambers and fuel systems to significantly lean the combustion mixture.[197] And Targa notes that the modifications will, "need turbochargers or externally driven blowers added as well."[198] Regarding the possibility of externally driven blowers, Targa points out the following:

> If a 2SLB engine does need an externally driven blower, this will be an electric blower and require electricity to operate. At this time, Eunice Gas Plant would have to significantly upgrade the power substation at the plant to operate blowers associated with these controls. The cost provided in Section 3 of this report does not include the cost to upgrade the electrical substation at the facility. An engineering design assessment would need to be completed before a total cost for the upgrade can be provided but is estimated at $1 million to $3 million.

[197] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 2-9.
[198] *Id.* at 2-10.

> Even with the power concerns, Targa has determined that this method of NOx control is feasible for the 2SLB engines at the facility.[199]

In Targa's Addendum, it more specifically describes the technologies included in its updated analysis, including adding a pre-combustion chamber with power cylinder heads, modifications to the fuel system, adding a turbocharger system, and various upgrades to the intercooler system.[200]

As Targa acknowledges, it's not clear to what degree – and at what cost – additional upgrades to the power substation would be required. And Targa has stated that these LEC controls are feasible regardless of power concerns. So any claim that electrical power upgrades would render this control infeasible must be more carefully evaluated based on more specific data (e.g., energy needs in kW and the costs of those energy needs) in order to be able to assess the cost effectiveness of the additional electricity usage that would be required to power any blowers, or any other potential electrified sources, as determined from a full engineering assessment.

3. Use of SCR.

Targa did not evaluate SCR for these units, primarily because it claimed that, "most 2SLB engines have a poor air-to-fuel ratio that will not support the SCR control."[201] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly because Targa does not consider LEC to be economical.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[202]

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[199] *Id.*

[200] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 7.

[201] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 2-11.

[202] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[203] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[204] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

B. Natural Gas-Fired Boilers (Units B-01 and B-02)

Targa also evaluated controls for the Units B-01 and B-02 natural gas-fired boilers. These boilers are Wickes Type A boilers, each with a permitted capacity of 100 MMBtu/hr that were manufactured in 1972.[205] The units each are subject to allowable NOx emission limits of 20.6 lb/hr and 90.0 tpy.[206]

Targa states that the two boilers already are using good combustion practices and have low NOx burners. Targa states that ultra-low NOx burners are available but would be technically infeasible at times for the Eunice Gas Processing Plant boilers because of the age of the boilers and the vendors' concerns with the higher Btu content of the fuel.[207] Targa also found SCR to be technically infeasible for the boiler claiming the significant power requirements would require the power at the plant to be significantly upgraded and redesigned. In addition, Targa found the selective non-catalytic reduction (SNCR) was not technically feasible due to concerns about how low loads will impact the temperature profile and optimal operating temperature of the control. Targa's dismissal of all three of these controls as technically infeasible only provides brief claims of technical infeasibility with no details specific to the Unit B-01 and B-02 boilers design or operation that make the particular control technically infeasible for the units. Further, issues of cost do not make a control technically infeasible. Instead, the costs of any requirements to alter a boiler to be able to operate with ultra-low NOx burners or to upgrade electricity to power SCR needs to be costed out and considered in the cost effectiveness analysis. NMED must require more information from Targa to exclude these controls as technically infeasible, particularly ultra-low NOx burners and SCR, especially given that Targa's

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[203] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.

[204] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[205] 11/29/2019 Title V Operating Permit For Targa Eunice Gas Processing Plant at A7.

[206] *Id.* at A11.

[207] November 2019 Four-Factor Analysis for Targa Eunice Gas Processing Plant at 2-13.

research of RACT/BACT/LAER Clearinghouse entries shows that these controls are commonly required for natural gas-fired industrial boilers.[208]

The only NOx control evaluated by Targa for the boilers is flue gas recirculation (FGR). Targa assumed that FGR would reduce NOx to 45 ppm, which would be 50% control from the base NOx emissions rate of 90 ppm.[209] At least one boiler manufacturer, Cleaver Brooks, states that FGR is one of the more commonly used methods to reduce NOx emissions and that it can achieve up to 80% NOx reduction.[210] However, the cost effectiveness of the control was calculated by Targa to be between $16,000 to $19,000/ton.[211] Part of the reason for the high cost effectiveness is that Targa assumed only a 20 year life of controls and a 5.5% interest rate. FGR consists of recycling a portion of the flue gas from the stack to the burner windbox. The NOx reduction occurs due to the recirculated flue gas reducing combustion temperatures and because of lowering the oxygen content in the flame zone.[212] The life of FGR should be the same as the life of the boiler. Targa did not identify the remaining useful life of boilers B-01 and B-02, but the boilers have been in operation since 1972 or 47 years. The lifetime of a boiler is typically thought to be at least 30 years, and Targa did not give any indication of any end of life for the boilers. Thus, Targa should have assumed a 30-year life of FGR. Also, as previously discussed, a lower interest rate should have been used, no higher than 4.7%.

However, the other reason the cost effectiveness of FGR appears to be so high at Units B-01 and B-02 is because the 2016 annual baseline emissions relied on by Targa are very low compared to the units' allowable emissions (8.08 and 6.73 tpy compared to 90 tpy allowable emissions each for Units B-01 and B-02). Yet, a review of the 2016 hourly emissions of NOx compared to the annual emissions of NOx indicates that the boilers operate very close to 8,760 hours per year. If the boilers' NOx emissions are expected to continue to be as low as indicated by the 2016 emission inventory, it seems questionable that the emission limits applicable to these units are reflective of the existing good combustion practices and low NOx burners. NMED should reduce the emission limits to reflect the current NOx controls on the boilers. If the boiler NOx emissions in 2016 are anomalous and not reflective of future operations of the boilers in 2028, then NMED should require a revised cost effectiveness analysis based on a more realistic estimate of annual NOx emissions.

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[208] *Id.* at Appendix A.

[209] *Id.* at 3-3 and at Appendix B (pdf pages 35 and 36 of document).

[210] *See* Cleaver Brooks, Strategies to Reduce NOx Emissions, Tip Sheet: October 2014, available at http://cleaverbrooks.com/september/. *See also* W.C. Rouse & Son, Low NOx Without Flue Gas Recirculation, in which it is stated that for gas-fired boilers, FGR can achieve 75-80% NOx reduction, available at https://www.wcrouse.com/low-nox-without-flue-gas-recirculation/.

[211] *Id.* at Appendix B (pdf pages 35 and 36 of document).

[212] EPA, AP-42 Emission Factor Document, Natural Gas Combustion, at page 3.

V. Targa Monument Gas Plant

The Targa Midstream Services, LLC Monument Gas Plant is a natural gas processing plant identified by NMED as potentially contributing to regional haze at the Carlsbad Caverns National Park Class I area.[213] NMED has described the facility processes as follows:

> The function of the facility is to process natural gas through inlet separation, an amine system for acid gas removal (carbon dioxide and hydrogen sulfide), dehydration for water removal, and the separation of methane from natural gas liquids (NGL). The natural gas is delivered to sales pipelines, propane is transported offsite with pressurized tank trunks, and the separated condensate is loaded into tank trucks for transport offsite.[214]

According to the permit, the plant includes seven RICE units, a steam boiler, heaters, gas turbines, storage tanks, vapor recovery units, an amine unit, and flares.[215]

In Targa's four-factor submittal, the company evaluated air pollution controls for the following emission units:

- Clark 2SLB RICE RA-8 (800 hp): Units C-01, C-02
- Clark 2SLB RICE RA-6 (600 hp): Units C-04, C-05, C-06
- Clark 2SLB RICE HRA-8 (880 hp): Unit C-24
- Cooper-Bessemer GMVA-8 (1,100 hp): Unit C-28
- Amine Gas Treating Unit / Flare: Unit AM-01 / F-03.[216]

The selection of these sources for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hr or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[217] The following provides a review of the company's four-factor analyses for the engines listed above. The Amine Gas Treating Unit/Flare is addressed in Section XXIII further below.

[213] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Monument Gas Plant at 1-1.
[214] Title V Operating Permit P110-R2M1 for Monument Gas Plant at A3.
[215] *Id.* at A5–A7.
[216] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 2-1.
[217] *Id.* at 1-3.

A. Units C-01, C-02, C-04 through C-06, C-24, and C-28: Natural Gas-Fired 2-Stroke Lean-Burn RICE

Units C-01 and C-02 are Clark RA-8 two-stroke lean-burn compressor engines that were constructed in 1956, each with a capacity of 800 hp.[218] These units each have an hourly NOx limit of 27.8 lb/hr and an annual NOx limit of 121.8 tpy.[219]

Units C-04 through C-06 are Clark RA-6 two-stroke lean-burn compressor engines that were also constructed in 1956, each with a capacity of 600 hp.[220] The three units each have an hourly NOx limit of 25.1 lb/hr and an annual NOx limit of 109.9 tpy.[221]

Unit C-24 is a Clark HRA-8 two-stroke lean-burn compressor engine that was constructed in 1969, with a capacity of 880 hp.[222] This unit has an hourly NOx limit of 41.9 lb/hr and an annual NOx limit of 183.5 tpy.[223]
Unit C-28 is a Cooper-Bessemer GMVA-8 two-stroke lean-burn compressor engine that was constructed in 1977, with a capacity of 1,100 hp.[224] This unit has an hourly NOx limit of 16.6 lb/hr and an annual NOx limit of 72.7 tpy.[225]

1. Evaluation of Baseline NOx Emissions

Targa's four-factor submittal includes unit-specific operating hours based on 2016 emission inventory calculations. Uncontrolled NOx emission rates (g/hp-hr) in Targa's original four-factor analysis are based on a single performance test conducted for each engine in April 2015. The actual emission rates for these units, based on this April 2015 testing, and the allowable NOx emission rates are shown in the table below.[226]

Table 12. Targa Monument Gas Plant 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Actual Emissions from April 2015 Test Data [g/hp-hr]
C-01	800	27.8	15.8	11.9
C-02	800	27.8	15.8	9.8
C-04	600	25.1	19.0	9.9
C-05	600	25.1	19.0	8.4
C-06	600	25.1	19.0	11.4

[218] Title V Operating Permit P110-R2M1 for Monument Gas Plant at A6.
[219] *Id.* at A8.
[220] *Id.* at A6.
[221] *Id.* at A8.
[222] *Id.* at A6.
[223] *Id.* at A8.
[224] *Id.* at A6.
[225] *Id.* at A8.
[226] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant Appendix B.

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Actual Emissions from April 2015 Test Data [g/hp-hr]
C-24	880	41.9	21.6	18.2
C-28	1,100	16.6	6.8	6.3

As shown, the actual emission rates for all units, with the exception of C-28, are much lower than the units' allowable hourly NOx emission rates so, either the 2015 test data for these units was not conducted while the engines were operating at maximum capacity or the allowable NOx emission rates for these units have been set unreasonably high. NMED should present information on the 2015 test data so the circumstances of the tests can be reviewed. Targa's February 2020 Addendum included the results from portable analyzer testing conducted over a few days in August 2016 for the engines at the Saunders Gas Plant, which presumably are the tests used in determining baseline emissions for the four-factor analysis for that source.[227] NMED and Targa should review performance tests at the Monument Gas Plant, that are based on EPA Reference Methods, to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. Citing variability in test data, Targa admits that these data are only a snapshot in time and only provide potential emissions based on that snapshot.[228] If testing is only done sporadically and is not done using EPA Reference Methods then it is questionable that such test data truly reflect an accurate projection of emissions expected over the lifetime of the controls being evaluated.

According to the August 2018 Title V renewal application for the Monument Gas Plant, NOx emissions were determined, "based on stack test data with a safety factor..."[229] The permitted rates for these units (with the exception of unit C-28)—that are based on stack test data—are significantly higher than the NOx emission rates that the company's four-factor cost effectiveness analysis is based upon, meaning NOx reductions estimates for the various control options considered may be underestimated. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on a more comprehensive estimate of emissions expected in 2028.

2. Use of Low Emission Combustion Technology

Targa describes the LEC control technologies for these 2SLB engines as "Clean Burn Technology (CBT)."[230] According to EPA, "[t]he term "clean-burn" technology is a registered trademark of Cooper Energy Systems and refers to engines designed to reduce NOx by operating at high air-to-fuel ratios."[231] In Targa's original submittal it specifically describes the LEC modifications for

[227] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 18-62.
[228] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 6.
[229] *See* August 2018 Title V Permit Application for Monument Gas Plant at pdf page 36.
[230] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 2-3.
[231] EPA AP-42 Chapter 3, Section 3.2 (July 2000) at 3.2-2.

these engines as including pre-combustion chambers and fuel systems to significantly lean the combustion mixture.[232] And Targa notes that the modifications will, "need turbochargers or externally driven blowers added as well."[233] In Targa's February 2020 Addendum, it more specifically describes the technologies included in its updated analysis, including adding a pre-combustion chamber with power cylinder heads, modifications to the fuel system, adding a turbocharger system, and various upgrades to the intercooler system.[234]

Targa determined that this LEC technology is a technically feasible option for the 2SLB RICE units at the Monument Gas Plant and the cost analysis provided in its four-factor analysis indicates this control could be cost effective for some of these units (e.g., Unit C-24). Despite this, Targa concludes the following:

> However, retrofitting with these technologies would require Targa to spend significant amounts of time (for design and installation) and capital. In addition, based on the predominant wind direction and that SO_2, not NOx, is the contaminant of interest for visibility impairment in Carlsbad Caverns, NOx emissions from these pieces of equipment are inconsequential for regional haze purposes. Thus, retrofitting the Monument Gas Plant engines would be uneconomical and unnecessary for improving visibility.[235]

In terms of being uneconomical, the cost analysis in Targa's four-factor submittal doesn't necessarily support this claim for all engines, and more importantly, the cost effectiveness of controls may be even more favorable than what is presented by Targa.

In its original November 2019 submittal, Targa presents cost effectiveness of controls for these units that range from $1,688–$33,892 per ton. The capital cost estimates are based on "manufacturer specification" and the annual operating and maintenance costs were provided by Targa.[236] Note, these annual operating and maintenance costs are higher than what was provided by other companies for LEC retrofits for similar engines.[237] Targa's February 2020 Addendum included a revised control cost analysis, with costs effectiveness ranging from $6,398–$155,568 per ton, based on much higher cost estimates, and based on higher controlled NOx emission rates.[238] The capital investment for the Clean Burn Technology in the original submittal totaled $900,000 per engine, compared to over $5 million in the

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[232] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 2-4.
[233] *Id*.
[234] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 7.
[235] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 7-1.
[236] *Id.* Appendix B. Note, Targa stated, on pdf page 8 of its February 2020 Addendum, that "the O&M cost included in the analyses were based on Targa's experience operating similar control devices at other sites for expected maintenance and repair."
[237] *See, e.g.,* November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant, which assumed O&M costs of $40,000/yr for Clark HRA-8 engines.
[238] *See* February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 7 and 96–102.

Addendum.[239] The original capital cost estimates are high, at $150—$270/hp, compared to other capital cost estimates for LEC controls at other similar engines.[240] The capital cost estimates in Targa's Addendum are significantly higher, at over $750/hp for some units (e.g., C-04 through C-06). It appears that the revised costs include $3 million for electrical power, which Targa indicated in its original submittal could cost between $1–$3 million but would require an engineering assessment in order to know the full cost of this upgrade.[241] Note, even without these electrical upgrades, the other capital costs come in at over $400/hp for some units, which is still significantly higher than the $/hp figures in Targa's original submittal.

In its original submittal, Targa stated that the Clean Burn Technology upgrades would either include turbochargers or externally driven blowers, with the electrical upgrades only necessary if blowers are used.[242] Even assuming the need for blowers and the highest cost estimate for upgrading the electrical substation (i.e., $3 million instead of $1 million), the cost effectiveness of these LEC controls is as low as $6,398/ton for unit C-24.[243] Assuming the electrical upgrades would cost $1 million instead of $3 million, or that electrical upgrades aren't needed would obviously result in much more favorable cost effectiveness of these controls.

Note that, Targa's submittal for the Saunders Gas Plant includes an analysis of the exact same LEC controls for the 2SLB RICE at that facility—e.g., requiring turbochargers or externally driven blowers—and the capital costs for that analysis are, generally, less than $140/hp. And Targa's February 2020 Addendum for the Eunice, Monument, and Saunders gas plants did not include higher cost estimates for increased electricity needs at the Saunders Gas Plant. It's true that there are on-site electrical generation capabilities at the Saunders Gas Plant (e.g., units G-01 through G-04) but Targa's analysis for this facility does not appear to reflect a measurable increase in capital cost expenditures associated with the externally driven blowers that may be required at this site for LEC controls at the 2SLB RICE. And at any rate, any cost analysis associated with upgrades to a power substation that serves the Monument Gas Plant should be considered separately, as part of a facility-wide assessment of the cost effectiveness of electrifying additional sources that could further reduce NOx emissions from the plant (e.g., electrification of engines).

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[239] Note, these original capital cost estimates are in line with other company analyses for similar engines, e.g., Harvest Four Corners Kutz Canyon Gas Processing Plant's analysis for Clark HBA-8 engines used capital cost estimates of $1,000,000. Also, EPA's 2000 RICE Update (p. 5-2) included capital cost estimates for third-party retrofit of a Clark Model HSRA, 2SLB 1,000 hp 8-cylindar engine at a pipeline station of $710,000.

[240] *See, e.g.,* Four-Factor analyses for Chaco Gas Plant (Clark 2SLB RICE at $140/hp), Saunders Gas Plant (Cooper-Bessemer 2SLB RICE at $90-$138/hp), Roswell Compressor Station No. 9 (Cooper-Bessemer 4SLB RICE at $90/hp), Jal No. 3 (Cooper-Bessemer 2SLB RICE at $123/hp).

[241] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Monument Gas Plant at 2-4 and 3-2.

[242] *Id.*

[243] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 101.

The annual hours of operation for these engines varies significantly. According to Targa's submittal, the annual hours of operation used in the four-factor analysis are based on 2016 emission inventory data, as shown in the table below:

Table 13. Targa Monument Gas Plant 2SLB RICE Units Annual Operation

Unit	Size [hp]	Hours of Operation From 2016 EI Calculations [hr/yr]
C-01	800	2,357
C-02	800	4,069
C-04	600	990
C-05	600	2,035
C-06	600	3,938
C-24	880	6,610
C-28	1,100	573
AVERAGE		2,939

In Targa's Addendum, it indicated that annual hours of operation depend on various factors—e.g., including whether units are working, when they require maintenance, etc. —and will vary each year from engine to engine but, overall, are generally uniform.[244] According to Targa, "each year the engines will operate with different hours of operation and fuel usage."[245] NMED should request operation data for additional years for these units in order to be able to better assess the cost effectiveness of controls for operating schedules that reflect the full range of usage for these engines.

In Targa's original submittal, its cost effectiveness analysis assumes controlled NOx emission rates of 2 g/hp-hr based on "information provided by the engine control vendor."[246] The corresponding NOx emissions reductions in Targa's original four-factor analysis for these units range from 68.3% to 89%.[247] Note, greater emissions reductions would result from control of units that are operating at levels closer to permitted levels (which are, again, based on test data for the units according to the source's Title V permit application) would mean that the LEC controls would be even more cost effective than what is shown in the original four-factor analysis. Targa specifically describes the control technology for these engines as able to reduce NOx emissions between 70% and 90%.[248] Subsequently, Targa's Addendum includes a new analysis of the cost effectiveness of reducing NOx emissions to levels of 4 g/hp-hr and 5 g/hp-hr, reflecting NOx emissions reductions of only 37–78%.[249]

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[244] *Id.* at 6.
[245] *Id.* at 6.
[246] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 3-2.
[247] *Id.* at Appendix B.
[248] *Id.*at 2-4.
[249] *See* February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 96—102.

In addition, as a result of assuming what could be unreasonably low NOx emission rates for current uncontrolled emissions from some of the 2SLB engines, i.e., emission rates based on performance test data that show much lower rates than the permitted limits for these units (that, according to Targa's Title V permit application, are based on stack data), Targa then also potentially further underestimates the magnitude of potential NOx reductions for these units in its cost effectiveness analysis. The permitted hourly NOx emission rates, based on stack test data, are notably higher than the actual emission rates used in the four-factor analysis for all but unit C-28, as shown in the table in the previous section.[250] Therefore, the potential emissions reductions achieved by retrofitting these units could be much greater than what the four-factor analysis shows due to potential underestimated baseline emissions, hours of operation, and emissions reductions. For uncontrolled permitted emission rates ranging from 15.8—21.6 g/hp-hr, controlled rates of 2 g/hp-hr would achieve 87—91% reduction in NOx emissions.

With respect to the life assumed for LEC control, Targa assumed a 20-year period.[251] Targa appears to base this on EPA's guidance default for SCR.[252] It's possible that LEC controls can last 25 years, as stated in other cost effectiveness analyses submitted to NMED for LEC controls.[253]
Also, Targa uses an interest rate of 5.5% which is likely high and therefore underestimates annualized costs of control for these engines. As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

Revising Targa's cost effectiveness analyses to address some of these issues, including assuming 1) a 4.7% interest rate (instead of 5.5%), 2) a 25-year life of LEC (instead of an assumed 20-year life), and 3) emissions reductions of 87—91% based on potential operation at permitted levels (based on stack test data), improves cost effectiveness of these controls even further, as shown in the table below. Note, this revised analysis uses Targa's original capital investment costs, since these are more in line with the cost analysis for its Saunders Gas Plant and with other capital cost estimates for LEC technology for similar engines; additional capital investments related to electrical capacity upgrades at the facility should be assessed, in more detail, as a separate broader analysis. Further note, this revised analysis assumes a NOx emissions reduction estimate for unit C-28 of just over 70%, based on this unit's actual emission rate, since this emission rate is in line with permitted emissions for this unit.

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[250] *Also see* August 2018 Title V Permit Application for Monument Gas Plant at pdf pages 44–47.
[251] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant Appendix B.
[252] *Id.*
[253] See 2019 Four-Factor submittals for Roswell Compressor Station and Jal No. 3 which both assume 25-year life of controls for LEC.

Table 14. Cost Effectiveness of LEC at Uncontrolled Monument Gas Plant Units C-01, C-02, C-04 through C-06, C-24, and C-28 to Reduce NO_x Levels to 2 g/hp-hr, Assuming 87—91% Reductions in NOx Emissions, a 4.7% Interest Rate, and a 25-Year Life of Controls

Unit	Size [hp]	Capital Cost of LEC to Reduce NOx from an Uncontrolled Rate [2019$]	Annual O&M Costs [2019$]	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (87—91% NOx Reduction) [2019$]	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC [2019$], $/ton
C-01	800	$900,000	$100,000	$161,951	2,357	29	$5,661/ton
C-02	800	$900,000	$100,000	$161,951	4,069	49	$3,279/ton
C-04	600	$900,000	$100,000	$161,951	990	11	$14,570/ton
C-05	600	$900,000	$100,000	$161,951	2,035	23	$7,088/ton
C-06	600	$900,000	$100,000	$161,951	3,938	44	$3,663/ton
C-24	880	$900,000	$100,000	$161,951	6,610	126	$1,289/ton
C-28	1,100	$850,000	$100,000	$158,509	573	3	$47,086/ton*

* Emissions reductions for Unit C-28 are based on controlling NOx emissions from the unit's actual emission rate of 6.8 g/hp-hr to 2 g/hp-hr (i.e., assuming NOx emissions reductions of just over 70%), since this uncontrolled emission rate is in line with permitted emissions for this unit.
Capital costs for C-28 are listed as $850,000 based on manufacturer specification.

The cost effectiveness of LEC control could be significantly lower than what is shown above for engines that operate more frequently than in 2016. Targa stated, in its February 2020 Addendum, that "[w]ith regards to the engine usage, Targa attempts to use its engines uniformly but this does not mean equally on a calendar year basis."[254] An analysis that assumes each engine operates at the average annual operation of all engines in 2016, which is roughly 3,000 hours per year, e.g., would lower the cost effectiveness of Unit C-01 to $5,080/ton, units C-04 and C-05 to $5,491/ton each, and unit C-28 to $10,226/ton.

Regarding the possibility of externally driven blowers that would require electrical upgrades, Targa points out the following:

> If a 2SLB engine does need an externally driven blower, this will be an electric blower and require electricity to operate. At this time, Eunice Gas Plant would have to significantly upgrade the power substation at the plant to operate blowers associated with these controls. The cost provided in Section 3 of this report does not include the cost to upgrade the electrical substation at the facility. An engineering design assessment would need to be completed before a total cost for the upgrade can be provided but is estimated at $1 million to $3 million.

[254] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 6.

> Even with the power concerns, Targa has determined that this method of NOx control is feasible for the 2SLB engines at the facility.[255]

As Targa acknowledges, it's not clear to what degree – and at what cost – additional upgrades to the power substation would be required. And Targa has stated that these LEC controls are feasible regardless of power concerns. So any claim that electrical power upgrades would render this control infeasible must be more carefully evaluated based on more-specific data (e.g., energy needs in kW and the costs of those energy needs) in order to be able to assess the cost effectiveness of the additional electricity usage that would be required to power any blowers, or any other potential electrified sources, as determined from a full engineering assessment.

3. Use of SCR.

Targa did not evaluate SCR for these units, primarily because it claimed that, "most 2SLB engines have a poor air-to-fuel ratio that will not support the SCR control."[256] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly because Targa does not consider LEC to be economical.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[257]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[258] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost

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[255] *Id.*

[256] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 2-5.

[257] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.

[258] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.

Manual[259] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

VI. Targa Saunders Gas Plant

The Targa Midstream Services, LLC Saunders Gas Plant is a natural gas processing plant identified by NMED as potentially contributing to regional haze at the Salt Creek Wilderness Area Class I area.[260] NMED has described the facility processes as follows:

> The function of the facility is to process natural gas, including dehydration and sweetening sour natural gas (removing sulfur and CO_2), and also remove lighter hydrocarbons (such as ethane and methane) from the inlet gas stream. The facility is capable of processing approximately 100 MMscf/d of gas.[261]

According to the permit, the plant includes nine two-stroke reciprocating internal combustion engines (RICE) used for compression, four 4-stroke generator RICE, an emergency generator, heaters, sulfur recovery unit and incinerator, storage tanks, an amine unit, and flares.[262] In Targa's four-factor submittal, the company evaluated air pollution controls for the following emission units:

- Cooper-Bessemer 2SLB RICE GMVA-10 (1,350 hp): Units C-01 through C-06
- Cooper-Bessemer 2SLB RICE GMV-10 (1,195 hp): Units C-07 and C-08
- Cooper-Bessemer GMVC-10 (1,800 hp): Unit C-09
- Ingersoll-Rand 4SRB RICE PKVG-8 (780 hp): Units G-01, G-02, G-03
- Amine Gas Treating Unit with Sulfur Recovery Unit and Incinerator: Unit AM-01 / I-01.[263]

The selection of these sources for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hr or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[264] The following provides a review of the company's

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[259] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[260] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 1-1.
[261] Title V Operating Permit P111-R2M2 for Saunders Gas Plant at A3.
[262] *Id.* at A6–A7.
[263] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 2-1.
[264] *Id.* at 1-3.

four-factor analyses for the engines listed above. Comments on the four-factor analysis for the amine gas treating unit are provided in Section XXIII further below.

A. Units C-01 through C-09: Natural Gas-Fired 2-Stroke Lean-Burn RICE

Units C-01 through C-06 are Cooper-Bessemer GMVA-10 2-stroke lean-burn compressor engines that were constructed in 1953, each with a capacity of 1,350 hp.[265] These units each have an hourly NOx limit of 32.6 lb/hr and an annual NOx limit of 142.8 tpy.[266]

Units C-07 and C-08 are Cooper-Bessemer GMV-10 2-stroke lean-burn compressor engines that were also constructed in 1953, each with a permitted capacity of 1,195 hp.[267] The two units each have an hourly NOx limit of 28.7 lb/hr and an annual NOx limit of 125.6 tpy.[268]

Unit C-09 is a Cooper-Bessemer GMVC-10 2-stroke lean-burn compressor engine that was constructed in 1953, with a capacity of 1,800 hp.[269] This unit has an hourly NOx limit of 43.2 lb/hr and an annual NOx limit of 189.2 tpy.[270]

1. Evaluation of Baseline NOx Emissions

Targa's four-factor submittal includes unit-specific operating hours based on 2016 emission inventory calculations. Uncontrolled NOx emission rates (g/hp-hr) in Targa's original four-factor analysis are based on a single performance test conducted for each engine in August 2016. The actual emission rates for these units, based on this August 2016 testing, and the allowable NOx emission rates are shown in the table below.[271]

Table 15. Targa Saunders Gas Plant 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Actual Emissions from August 2016 Test Data [g/hp-hr]
C-01	1,350	32.6	11.0	2.05
C-02	1,350	32.6	11.0	10.78
C-03	1,350	32.6	11.0	4.99
C-04	1,350	32.6	11.0	3.87
C-05	1,350	32.6	11.0	7.21
C-06	1,350	32.6	11.0	8.3

[265] Title V Operating Permit P111-R2M2 for Saunders Gas Plant at A6.
[266] *Id.* at A9.
[267] *Id.* at A7. Note, Unit C-08 has a maximum capacity of 1,350 hp and a permitted capacity of 1,195 hp.
[268] *Id.* at A9.
[269] *Id.* at A7.
[270] *Id.* at A9.
[271] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant Appendix B.

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Actual Emissions from August 2016 Test Data [g/hp-hr]
C-07	1,195	28.7	10.9	7.35
C-08	1,195	28.7	10.9	9.13
C-09	1,800	43.2	10.9	5.54

As shown, the actual emission rates for most units, with the exception of C-02 and a few others, are much lower than the units' allowable hourly NOx emission rates, so either the 2016 testing for these units was not conducted while the engines were operating at maximum capacity or the allowable NOx emission rates for these units have been set unreasonably high. Targa's February 2020 Addendum included the results from portable analyzer testing conducted over a few days in August 2016 for the engines at the Saunders Gas Plant, which presumable are the tests used in determining baseline emissions for the four-factor analysis.[272] NMED and Targa should review other performance tests, that are based on EPA Reference Methods, for these units to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. Citing variability in test data, Targa admits that these data are only a snapshot in time and only provide potential emissions based on that snapshot.[273] If testing is only done sporadically and is not done using EPA Reference Methods then it is questionable that such test data truly reflect an accurate projection of emissions expected over the lifetime of the controls being evaluated.

According to the September 2018 Title V renewal application for the Saunders Gas Plant, NOx emissions for units C-01 through C-07 were," calculated using stack test data from 2/22/1994 with a 20% safety factor."[274] Note, permitted emission rates for units C-08 and C-09 were calculated using EPA AP-42 emission factors (Table 3.2-2).[275] The permitted rates for these units (with the exception of unit C-02, but especially for units C-01, C-03, and C-04)—that are based on stack test data—are significantly higher than the NOx emission rates that the company's four-factor cost effectiveness analysis is based upon, even considering the 20% "safety factor", meaning NOx reductions estimates for the various control options considered for these units may be underestimated. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on a more comprehensive estimate of emissions expected in 2028.

1. Use of Low Emission Combustion Technology

Targa describes the LEC control technologies for these 2SLB engines as "Clean Burn Technology (CBT)."[276] In Targa's original submittal it specifically describes the LEC modifications for these

[272] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 18-62.
[273] *Id.* at pdf page 6.
[274] *See* September 2018 Title V Permit Application for Saunders Gas Plant at pdf page 38.
[275] *Id.*
[276] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 2-7.

engines as including pre-combustion chambers and fuel systems to significantly lean the combustion mixture.[277] And Targa notes that the modifications will, "need turbochargers or externally driven blowers added as well."[278] In Targa's February 2020 Addendum, it more specifically describes the technologies included in its updated analysis, including adding a pre-combustion chamber with power cylinder heads, modifications to the fuel system, adding a turbocharger system, and various upgrades to the intercooler system.[279]

Targa determined that this LEC technology is a technically feasible option for the 2SLB RICE units at the Saunders Gas Plant and the cost analysis provided in its four-factor analysis indicates this control could be cost effective for these units, depending on the baseline emission rates and operating schedules. Despite this, Targa concludes these retrofits would be uneconomical.[280]

The cost analysis in Targa's four-factor submittal doesn't necessarily support this claim for these engines, and more importantly, the cost effectiveness of controls may be even more favorable than what is presented by Targa.

In its original November 2019 submittal, Targa presents cost effectiveness of controls for these units that range from $2,754–$277,724 per ton.[281] The capital cost estimates are based on "manufacturer specification" and the annual operating and maintenance costs were provided by Targa.[282] Targa's February 2020 Addendum included an additional control cost analysis based on higher controlled NOx emission rates; Targa also specified that the capital control cost estimates include engineering costs (e.g., equipment / installation, structural, drawings, etc.).[283] The capital cost estimates are similar, at $80—$138 per hp, compared to other capital cost estimates for LEC controls at other similar engines.[284]

The annual hours of operation for these engines varies quite a bit. According to Targa's submittal, the annual hours of operation used in the four-factor analysis are based on 2016 emission inventory data, as shown in the table below:

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[277] *Id.*

[278] *Id.*

[279] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 7.

[280] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 7-1.

[281] *Id.* at 3-2. Note, the $277,724/ton figure for unit C-01 represents the cost effectiveness of reducing NOx emissions from a baseline level for this unit (based on a single performance test from 2016) of 2.04 g/hp-hr to a controlled emission rate of 2 g/hp-hr; if this unit were operating at its permitted emission rate (that is also based on performance testing, from 1994) the cost effectiveness of this control would be *significantly* lower (i.e., <$2,000/ton).

[282] *Id.* Appendix B. Note, Targa stated, on pdf page 8 of its February 2020 Addendum, that "the O&M cost included in the analyses were based on Targa's experience operating similar control devices at other sites for expected maintenance and repair."

[283] *See* February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 7 and 114–122.

[284] *See, e.g.,* Four-Factor analyses for Roswell Compressor Station No. 9 (Cooper-Bessemer 4SLB RICE at $90/hp) and Jal No. 3 (Cooper-Bessemer 2SLB RICE at $123/hp).

Table 16. Targa Saunders Gas Plant 2SLB RICE Units Annual Operation

Unit	Size [hp]	Hours of Operation From 2016 EI Calculations [hr/yr]
C-01	1,350	8,656
C-02	1,350	4,971
C-03	1,350	5,321
C-04	1,350	7,770
C-05	1,350	5,431
C-06	1,350	1,910
C-07	1,195	5,622
C-08	1,195	2,948
C-09	1,800	5,989

In Targa's Addendum, it indicated that annual hours of operation depend on various factors—e.g., including whether units are working, when they require maintenance, etc.—and will vary each year. According to Targa, "each year the engines will operate with different hours of operation and fuel usage."[285] NMED should request operation data for additional years for these units in order to be able to better assess the cost effectiveness of controls for operating schedules that reflect the full range of usage for these engines.

In Targa's original submittal, its cost effectiveness analysis assumes controlled NOx emission rates of 2 g/hp-hr based on "information provided by the engine control vendor."[286] The corresponding NOx emissions reductions in Targa's four-factor analysis for these units range from 2.4% to 81.4%.[287] Note, greater emissions reductions would result from control of units that are operating at levels closer to permitted levels (which are, again, based on test data for Units C-01 through C-07 according to the source's Title V permit application) would mean that the LEC controls would be even more cost effective than what is shown in the original four-factor analysis. And, in fact, Targa states that "[t]he Clean Burn technology will reduce NOx emissions by 81%."[288] For uncontrolled permitted emission rates of 11 g/hp-hr, controlled rates of 2 g/hp-hr would achieve an 81% reduction in NOx emissions, which is exactly what the Clean Burn technology is promising to achieve for all of these units.

As a result of assuming what could be unreasonably low NOx emission rates for baseline uncontrolled emissions from some of the 2SLB engines, i.e., emission rates based on performance test data that show much lower rates than the permitted limits for these units

[285] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 6.
[286] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 3-2.
[287] *Id.* at Appendix B.
[288] *Id.*at 2-7.

(that, according to Targa's Title V permit application, are based on stack data for all units but C-08 and C-09), Targa then also potentially further underestimates the magnitude of potential NOx reductions for these units in its cost effectiveness analysis. Therefore, the potential emissions reductions achieved by retrofitting these units could be much greater than what the four-factor analysis shows due to potential underestimated baseline emissions, hours of operation, and emissions reductions.

With respect to the life assumed for LEC control, Targa assumed a 20-year period.[289] Targa appears to base this on EPA's guidance default for SCR.[290] It's possible that LEC controls can last 25 years, as stated in other cost effectiveness analyses submitted to NMED for LEC controls.[291]
Also, Targa uses an interest rate of 5.5% which is likely high and therefore underestimates annualized costs of control for these engines. As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

Revising Targa's cost effectiveness analyses to address some of these issues, including assuming 1) a 4.7% interest rate (instead of 5.5%), 2) a 25-year life of LEC (instead of an assumed 20-year life), and 3) emissions reductions of 81% based on potential operation at permitted levels (largely based on stack test data), improves cost effectiveness of these controls even further, as shown in the table below. Note, this revised analysis reflects the large range in operating hours, based on 2016 data, which may not be representative of individual engine usage in other years.

Table 17. Cost Effectiveness of LEC at Uncontrolled Saunders Gas Plant Units C-01 through C-09 to Reduce NO_x Levels to 2 g/hp-hr, Assuming 81% Reductions in NOx Emissions, a 4.7% Interest Rate, and a 25-Year Life of Controls, 2019 $

Unit	Size [hp]	Capital Cost of LEC to Reduce NOx from a Permitted Rate of 11 g/hp-hr	Annual O&M Costs	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (81% NOx Reduction)	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC, $/ton
C-01	1,350	$942,500	$100,000	$164,876	8,656	116	$1,422
C-02	1,350	$942,500	$100,000	$164,876	4,971	67	$2,476
C-03	1,350	$942,500	$100,000	$164,876	5,321	71	$2,314
C-04	1,350	$942,500	$100,000	$164,876	7,770	104	$1,584
C-05	1,350	$942,500	$100,000	$164,876	5,431	73	$2,267

[289] *Id.* at Appendix B.
[290] *Id.*
[291] See 2019 Four-Factor submittals for Roswell Compressor Station and Jal No. 3 which both assume 25-year life of controls for LEC.

Unit	Size [hp]	Capital Cost of LEC to Reduce NOx from a Permitted Rate of 11 g/hp-hr	Annual O&M Costs	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (81% NOx Reduction)	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC, $/ton
C-06	1,350	$942,500	$100,000	$164,876	1,910	26	$6,445
C-07	1,195	$945,000	$100,000	$165,048	5,622	66	$2,504
C-08	1,195	$945,000	$100,000	$165,048	2,948	35	$4,776
C-09	1,800	$615,500	$100,000	$142,367	5,989	106	$1,346

The cost effectiveness of LEC control could be significantly lower than what is shown above for engines that operate more frequently than in 2016. Targa stated, in its Addendum, that "[w]ith regards to the engine usage, Targa attempts to use its engines uniformly but this does not mean equally on a calendar year basis."[292] An analysis that assumes each engine operates at the average annual operation across all engines in 2016, which is roughly 5,400 hours per year, would result in cost effectiveness estimates as low as $2,279/ton for unit C-06 and $2,606/ton for unit C-08.

2. Use of SCR.

Targa did not evaluate SCR for these units, primarily because it claimed that, "most 2SLB engines have a poor air-to-fuel ratio that will not support the SCR control."[293] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly because Targa does not consider LEC to be economical.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[294]

[292] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 13.
[293] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 2-8.
[294] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[295] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[296] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

B. Units G-01, G,02, and G-03: Natural Gas-Fired 4-Stroke Rich-Burn RICE

Units G-01 through C-03 are Ingersoll-Rand PKVG-8 4-stroke rich-burn generator engines that were constructed in 1953, each with a capacity of 780 hp.[297] These units each have an hourly NOx limit of 34.2 lb/hr and an annual NOx limit of 149.8 tpy.[298]

1. Evaluation of Baseline NOx Emissions

Targa's four-factor submittal includes baseline unit-specific NOx emission rates in hours per year and tons per year, based on 2016 emission inventory calculations.[299] Operating hours can be calculated based on these data. These baseline NOx emission rates and the allowable NOx emission rates from the source's Title V permit are shown in the table below.[300]

Table 18. Targa Saunders Gas Plant 4SRB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Baseline Emissions [lb/hr]
G-01	780	34.2	19.81
G-02			21.63
G-03			17.4

As shown, the baseline emission rates for all three units are significantly lower than the units' allowable hourly NOx emission rates so, either the baseline emissions for these units is not reflective of operation at maximum capacity or the allowable NOx emission rates for these units

[295] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[296] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[297] Title V Operating Permit P111-R2M2 for Saunders Gas Plant at A7.
[298] *Id.* at A9.
[299] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant Appendix B.
[300] *Id*.

have been set unreasonably high. NMED and Targa should review performance tests for these units to ensure that the actual emission rates can be considered to truly reflect baseline emissions over the lifetime of the controls being evaluated.

According to the September 2018 Title V renewal application for the Saunders Gas Plant, NOx emissions for units G-01 through G-03 were," calculated using stack test data from 2/22/1994 with a 20% safety factor."[301] The permitted rates for these units—that are based on stack test data—are significantly higher than the baseline NOx emission rates that the company's four-factor cost effectiveness analysis is based upon, even considering the 20% "safety factor", meaning NOx reductions estimates for the various control options considered for these units may be underestimated. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on a more comprehensive estimate of emissions expected in 2028.

2. Use of Non-Selective Catalytic Reduction

Targa determined that non-selective catalytic reduction (NSCR) is a technically feasible option for the 4SRB RICE units at the Saunders Gas Plant and the cost analysis provided in its four-factor analysis indicates this control could be very cost effective for these units.[302] Despite this, Targa concludes these retrofits would be uneconomical.[303]

The cost analysis in Targa's four-factor submittal doesn't support this claim for these engines, and the cost effectiveness of controls may be even more favorable than what is presented by Targa.

In its November 2019 submittal, Targa presents cost effectiveness of controls for G-01, G-02, and G-03 of $259/ton, $231/ton, and $287/ton, respectively.[304] The capital cost estimates are based on "information received from engine control vendors or knowledge on the particular equipment."[305] Targa's February 2020 Addendum did not include any revisions to these cost estimates.

The annual hours of operation for these engines is around 7,000 hours per year, based on the pound per hour and ton per year emission rates provided in Targa's submittal:

[301] *See* September 2018 Title V Permit Application for Saunders Gas Plant at pdf page 37.
[302] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 2-6 and 3-2.
[303] *Id.* at 7-1.
[304] *Id.* at 3-2.
[305] *Id.* at B-1.

Table 19. Targa Saunders Gas Plant 4SRB RICE Units Annual Operation Based on 2016 EI Calculations

Unit	Size [hp]	NOx Baseline Emissions [lb/hr]	NOx Baseline Emissions [tpy]	Hours of Operation [hr/yr]
C-01	780	19.81	69.47	7,014
C-02	780	21.63	77.28	7,146
C-03	780	17.14	63.52	7,412

NMED should request operation data for additional years for these units in order to be able to better assess the cost effectiveness of controls for operating schedules that reflect greater usage of these engines, as allowed by current permit limits, e.g., if increased usage would be more representative of typical operation in 2028.

In Targa's submittal, its cost effectiveness analysis assumes controlled NOx emission rates of 0.986 g/hp-hr, based on "a similar unit at the site which is controlled by NSCR."[306] The corresponding NOx emissions reductions in Targa's four-factor analysis for units G-01, G-02, and G-03 are 91.9%, 92.6%, and 90.7% respectively.[307] Note, greater emissions reductions would result from control of these units if they operate at levels closer to permitted levels (which are, again, based on test data), meaning NSCR would be even more cost effective than what is shown in Targa's four-factor analysis. Targa states that, "NSCR controls are typically 90% or greater."[308] For uncontrolled permitted emission rates of 34.2 g/hp-hr, controlled rates of 0.986 g/hp-hr would achieve 97% reduction in NOx emissions. According to EPA's Alternative Control Techniques document for RICE, NSCR vendors quote NOx emission reduction efficiencies of 90 to 98%, resulting in an expected range of controlled NOx emissions from 0.3-1.6 g/hp-hr.[309]

As a result of assuming what could be low NOx emission rates for baseline uncontrolled emissions from these 4SRB RICE, i.e., emission rates based on performance test data that show lower rates than the permitted limits for these units (that, according to Targa's Title V permit application, are also based on stack data), Targa then also potentially further underestimates the magnitude of potential NOx reductions for these units in its cost effectiveness analysis. Therefore, the potential emissions reductions achieved by retrofitting these units could be much greater than what the four-factor analysis shows due to potential underestimated baseline emissions, hours of operation, and emissions reductions.

With respect to the life assumed for LEC control, Targa assumed a 10-year period.[310] Targa does not provide any justification for this assumption for the life of controls. In the NPCA

[306] *Id*. at 3-1.
[307] *Id.* Appendix B.
[308] *Id.*at 2-6.
[309] EPA 1993 Alternative Control Techniques Document for RICE at 2-10 to 2-11.
[310] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant Appendix B.

March 2020 Oil and Gas Four-Factor Report, we assumed a 15-year life of controls in determining the cost effectiveness of NSCR control for 4SRB RICE.[311]

Also, Targa uses an interest rate of 8.25% which is high and therefore underestimates annualized costs of control for these engines. As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

Revising Targa's cost effectiveness analyses to address some of these issues, including assuming 1) a 4.7% interest rate (instead of 8.25%), 2) a 15-year life of NSCR (instead of an assumed 10-year life), and 3) emissions reductions of 97% based on potential operation at permitted levels (largely based on stack test data), improves cost effectiveness of these controls even further, as shown in the table below.

Table 20. Cost Effectiveness of NSCR at Uncontrolled Saunders Gas Plant Units G-01, G-02, and G-03 to Reduce NO_x Levels to 0.986 g/hp-hr, Assuming 97% Reductions in NOx Emissions, a 4.7% Interest Rate, and a 15-Year Life of Controls

Unit	Size [hp]	Capital Cost of NSCR to Reduce NOx from a Permitted Rate [2019$]	Annual O&M Costs [2019$]	Total Annualized Costs of LEC to Reduce NOx to 0.986 g/hp-hr (97% NOx Reduction) [2019$]	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of NSCR [2019$], $/ton
C-01	780	$8,206	$15,308	$16,083	7,014	116	$138/ton
C-02	780	$8,206	$15,308	$16,083	7,146	119	$136/ton
C-03	780	$8,206	$15,308	$16,083	7,412	123	$131/ton

Based on this analysis, it is *extremely* cost effectiveness to retrofit these 4SRB RICE with NSCR and would result in the removal of over 350 tons per year of NOx.

VII. DCP Artesia Gas Plant

The Artesia Gas Plant is a natural gas processing plant that removes condensate, H_2S and CO_2 in an amine unit, and separates natural gas liquids.[312] The plant is located about 15 miles east-southeast of Artesia, New Mexico. It is owned/operated by DCP Midstream. The plant consists of numerous natural gas-fired four-stroke rich-burn RICE units, natural gas-fired four-stroke lean-burn RICE, boilers, amine contactor, flares, and other emissions sources.[313] Of all of those sources of emissions, NMED apparently only requested a four-factor analysis for the flares at

[311] *See* NPCA March 2020 Oil and Gas Four-Factor Report at 20.
[312] 6/27/2017 Title V Permit No. P095-R3 for Artesia Gas Plant at A3.
[313] *Id.* at A6 to A8.

the plant. Notably, all of the four-stroke rich-burn RICE are equipped with nonselective catalytic reduction for NOx control. In Section XXIII further below, we provide comments on the four-factor analysis for the flares associated with the amine unit.

VIII. Harvest Four Corners – Kutz Canyon Gas Plant

Kutz Canyon Gas Plant is a natural gas processing plant that removes ethane and heavier hydrocarbons from natural gas. It is operated by Harvest Four Corners, LLC. The facility is located in San Juan County, about 3.1 miles south of Bloomfield, New Mexico. According to NMED's Statement of Basis for a New Source Review (NSR) permit for the facility, "The Kutz I Plant removes heavier hydrocarbons using a refrigerated lean oil absorption process and was built in 1936. The Kutz II Plant removes heavier hydrocarbons using a cryogenic process and was added to the facility much later, in 1975. The facility operates 8760 hours per year."[314] The Title V operating permit for the facility indicates that the plant includes several natural gas-fired turbines, boilers, several natural gas-fired RICE, heaters, boilers, and flares.[315] In Harvest Four Corner's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Solar Centaur 40 combustion turbines (Units 1-6 and Units 19 and 20)
- Clark HRA-8 two-stroke lean burn RICE (Units 16, 17, and 18)[316]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tons per year (tpy), which is the criteria established by NMED to identify sources subject to four-factor analyses.[317] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

Harvest Four Corners used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[318] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[319] The current bank prime rate is 3.25%.[320] The highest the bank

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[314] NMED Statement of Basis, NSR Permit No. 0301-M11 and P097-R3-R3M1, 8/20/2019, at 1.
[315] Title V Operating Permit P097-R3 for Kutz Canyon Processing Plant at A6 to A8.
[316] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 1-2.
[317] *Id.*
[318] *Id.* at Section 8.0 Supporting Documentation.
[319] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[320] https://www.federalreserve.gov/releases/h15/.

prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[321] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[322] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

B. Solar Centaur Natural Gas-Fired Combustion Turbines (Units 1-8 and 19 and 20) at the Kutz Canyon Gas Plant.

The combustion turbines evaluated at the Kutz Canyon Gas Plant are Solar combustion turbines, model Centaur 40 of 3830 hp capacity (Units 1-6) and of 3016 hp capacity (Units 19 and 20).[323] These units were manufactured between 1975 and 1981.[324] Under the terms of the permit, the units are subject to the following hourly and annual emission limits of NOx.

Table 21. Limits from Kutz Canyon Gas Plant Title V Permit for the Units 1-8 and 19-20 Combustion Turbines[325]

Combustion Turbine Unit ID	NOx limit, lb/hr	NOx limit, tpy
1	15.5	67.9
2	15.5	67.9
3	15.5	67.9
4	15.5	67.9
5	15.5	67.9
6	15.5	67.9
19	15.5	67.9
20	15.5	67.9

Units 19 and 20 are also subject to NOx limits of 161.91 ppmv at 15% O_2, pursuant to 40 C.F.R. Part 60, Subpart GG.[326]

Harvest Four Corners evaluated one control option for these combustion turbines: Solar's SoLoNOx combustion system. The company did not evaluate SCR, claiming that it would not operate effectively at the units and that there was not space available for SCR or power

[321] https://fred.stlouisfed.org/series/DPRIME.
[322] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.
[323] Title V Operating Permit P097-R3 for Kutz Canyon Processing Plant at A6.
[324] *Id.*
[325] *Id.* at A9-A10.
[326] *Id.* at A26.

capabilities for such SCR systems.[327] For reasons previously discussed above and in the NPCA Oil and Gas Four-Factor Report, SCR should have been considered as a technically feasible control for these natural gas-fired combustion turbines.

1. Baseline Emissions for the Units 1 – 6 and 19-20 Combustion Turbines.

Harvest Four Corners states that its cost effectiveness analyses for SoLoNOx were based on the 2016 emission inventory submittal.[328] In its cost data sheets in Section 8.0 of its four-factor analysis, the company provided the 2016 emission inventory calculations for the combustion turbines evaluated, but the company did not specify the actual 2016 operating hours for each unit.[329] This is inconsistent with most other four-factor analyses submitted to NMED. Submittal of operating hours is very important for understanding the operating capacity factor of the units, and NMED must require that more specific operational data be made public for the units as part of the four-factor analyses of controls. The company also provided the NOx ppm rate, but it was "converted from 2016 [emission inventory] calculations and data."[330]

Specifically, the company's cost data sheets indicate that the NOx ppm rate for each unit is 67.61 ppm.[331] That NOx concentration was then compared to the NOx emission rate guarantee from SoLoNOx of 25 ppm to determine the percent NOx reduction which was then multiplied by 2016 tpy emissions to determine the NOx removed for the cost effectiveness analysis of SoLoNOx. NMED must require Harvest Four Corners to provide more specific data on how the NOx ppm rate was calculated. Further, each of the units is subject to emission testing requirements of the Title V permit.[332] Such actual emissions tests should be evaluated as well (including the circumstances of the test data) to ensure that the baseline emissions inventory and emission rates are reflective of current actual emissions and emissions expected from the units in 2028. A review of Title V permit application data for the Kutz Canyon Gas Plant on the NMED's Emissions Analysis Tool did not find any other emissions testing data available for these units.

Units 19 and 20 are also subject to NOx limits of 161.91 ppmv at 15% O_2, pursuant to 40 C.F.R. Part 60, Subpart GG as discussed above. This is 2.4 times higher than the 67.61 ppm base NOx rate relied upon by Harvest Four Corners to determine the tons per year of NOx removed due to SoLoNOx. In addition, Units 19 and 20 are different Solar Centaur models than Units 1-6 (T4001 versus T4002). Further, Units 19 and 20 have a lower horsepower rating than Units 1-6. Yet, all eight units were assumed to have the same uncontrolled NOx baseline emission rate. The discrepancies between these two NOx rates need to be addressed by NMED to ensure that

[327] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-4 to 2-5.
[328] *Id.* at 2-10.
[329] *Id.* at Section 8.0, pdf pages 30-37.
[330] *Id.*
[331] *Id.*
[332] Title V Operating Permit P097-R3 for Kutz Canyon Processing Plant at A25.

baseline emissions are based on a valid analysis of actual emissions that are projected to occur in 2028.

2. Evaluation of SoLoNOx for the Combustion Turbines at Units 1-6 and 19-20.

Harvest Four Corners indicates that SoLoNOx can achieve a NOx rate of 25 ppm, which it claims is a reduction of 63% "based on the currently permitted hourly emission rate and turbine stack parameters."[333] This makes clear that Harvest Four Corners is using the 67.71 ppm NOx rate identified in its SoLoNOx cost data sheets along with the 25 ppm NOx rate expected from SoLoNOx to calculate the tons per year NOx reductions expected with SoLoNOx.[334] This statement implies that the NOx baseline emission rate of 67.71 ppm that Harvest Four Corners cites in its SoLoNOx cost data sheets is based on the allowable pound per hour emission limits applicable to each unit. However, in the cost data sheets of Section 8.0 of the Kutz Canyon Gas Plant four-factor analysis, it is stated that the 67.71 ppmv was calculated from the 2016 emission inventory data. Given that this baseline rate forms the basis of the company's claimed NOx removal efficiency with SoLoNOx, NMED must disclose the basis for this base concentration.

In terms of the life of SoLoNOx controls in the cost effectiveness analyses, Harvest Four Corners' analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[335] In the table below, Harvest Four Corners' cost effectiveness analyses of SoLoNOx were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate.

[333] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-3.
[334] A 25 ppm NOx rate reflects 63% NOx reduction from a 67.71 ppm NOx rate.
[335] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

Table 22. Revised Cost Effectiveness of SoLoNOx at Units 1-6 and 19-20 of the Kutz Canyon Gas Plant, to Reflect a 4.7% Interest Rate and a 25 Year Life

Unit	Harvest Four Corners' Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	Harvest Four Corners' Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25 Year Life
1	$61,603	$2,246/ton	$54,666	$1,993/ton
2	$61,603	$2,412/ton	$54,666	$2,141/ton
3	$61,603	$1,983/ton	$54,666	$1,760/ton
4	$78,339	$23,111/ton	$68,433	$20,183/ton
5	$78,339	$2,145/ton	$68,433	$1,873/ton
6	$78,339	$1,910/ton	$68,433	$1,668/ton
19	$61,603	$4,779/ton	$54,666	$4,242/ton
20	$61,603	$2,043/ton	$54,666	$1,813/ton

It must be noted that, for some unexplained reason, the capital cost to install SoLoNOx at Units 4, 5, and 6 was $200,000 higher than the capital cost to install SoLoNOx at the other combustion turbine units. Yet, Units 4, 5, and 6 are the same turbine model as Units 1, 2, and 3 (Model T4002).[336] NMED should evaluate the reason for the higher capital cost of SoLoNOx at Units 4, 5, and 6.

For Unit 4, the unit had very low NOx emissions in 2016 of 5.38 tpy, and thus the cost effectiveness of SoLoNOx was very high at this unit. NMED must ensure that these low NOx emissions at Unit 4 are not anomalous and that the company's baseline emissions for the unit are reflective of expected operations in 2028. With the exception of Unit 4, the cost effectiveness of SoLoNOx at these combustion turbines are in the range of $1760/ton to $4,242/ton to achieve 63% NOx reduction, which is very cost effective.

3. SCR at Units 1-6 and 19-20 at Kutz Canyon Gas Plant

As discussed above, Harvest Four Corners did not evaluate SCR for any of the combustion turbine units, claiming that the exhaust temperatures of the turbines is 1,271 degrees Fahrenheit which the company claims would negatively impact SCR operation, and also that there are site-specific space limitations for installation of SCR. With respect to space limitations, as discussed in Section I.B.3. above, most SCR retrofits have space limitations, because the facility was not likely designed to have space to accommodate SCR. There have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints. For example, for many large coal-fired power plants, SCR reactors

[336] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at Section 8.0.

have been elevated above the air preheaters. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new foundations to make way for the SCR reactor.[337] Thus, before NMED accepts a very brief claim of retrofit difficulty of SCR at any emissions unit being evaluated for reasonable progress controls, it is imperative that NMED ask Harvest Four Corners for a site plan and photos that shows whatever space constraints are being claimed, and that NMED ask the company to consult with SCR vendors for options for SCR installation at the gas turbines.

Depending on the proximity of the gas turbines, it is possible that one SCR reactor could be used by more than one combustion turbine. This would reduce costs and potentially be easier to install at the site. NMED should require all possibilities for SCR installation to be evaluated and documented by Enterprise. The state must not simply discount this highly effective NOx control based on a claim of some retrofit difficulty.

Regarding the company's stated exhaust temperature of 1,271 degrees Fahrenheit, NMED should determine if this is the sustained temperature of the gas turbines or the maximum temperature of the exhaust expected from the Units 1-6 and Unit 19-20 gas turbines. There are options for dealing with high exhaust temperatures of simple cycle turbines to enable the use of SCR. The Buckingham Compressor Station which is proposed to be constructed in Virginia would be equipped with Solar turbines with SoLoNOx, SCR, and cooling air skids.[338] Essentially, this provides for the injection of tempering air at the turbine discharge (upstream of the SCR) to cool the exhaust temperature to the optimal temperature of the SCR catalyst.[339]

Further, these high exhaust temperatures are another reason why NMED should investigate routing more than one combustion turbine exhaust to a common SCR. The routing of the turbine exhausts from multiple turbines to one SCR reactor will allow for some cooling of the exhaust before it enters the SCR. Salt River Project (SRP) is planning to route the flue gas from one boiler at the Coronado Generating Station in Arizona to an existing SCR reactor that had previously been constructed at Coronado Unit 2.[340] It will be a shared SCR system, although it must be noted that the Coronado Unit 1 SCR was designed as a split (two towers within one

[337] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, , available at https://www.onepetro.org/conference-paper/SPE-66501-MS.
[338] *See* May 25, 2018 Permit Application for Altlantic Coast Pipeline LLC, Buckingham Compressor Station, at pdf page 129 (Design Summary), which is available for download at https://www.deq.virginia.gov/Programs/Air/BuckinghamCompressorStationAirPermit/BuckinghamCompressorStationArchivedDocuments.aspx.
[339] *See,* e.g., Buzanowski, Mark A. and Sean P. McMenamin, Peerless Mfg. Co., Automated Exhaust Temperature Control for Simple Cycle Power Plants, available at https://www.powermag.com/automated-exhaust-temperature-control-for-simple-cycle-power-plants/. *See also* Mitsubishi Hitachi Power Systems (MHPS) webpage on SCR systems for simple cycle turbines at https://amer.mhps.com/scr-for-simple-cycle-gas-turbines.html.
[340] *See* January 6, 2020, SRP Newsroom, SRP Selects Operation Plan for Coronado Generating Station, Units 1 and 2 to Run on Existing Selective Catalytic Reduction until 2032, available at https://media.srpnet.com/srp-selects-operation-plan-for-coronado-generating-station/.

reactor) SCR system. So, according to SRP, each unit will have its own SCR within one reactor. Such an approach seems like it could be a viable, more cost effective control option for co-located combustion turbines at compressor stations.

One further reason that Harvest Four Corners identified for SCR not being feasible was due to the electricity needs of the SCR. Harvest Four Corners states that it "does not anticipate that the current electricity availability at Kutz will be sufficient to support the substantial energy burden associated with SCR control" and that "[i]nstallation of this control will require the facility to expand its current power generation."[341] The site has two onsite combustion turbine generators in Units 19 and 20. The Title V Permit states that each of these two generators cannot exceed 2400 kilowatts, and also states that only one unit can operate at any given time.[342] This condition was apparently imposed pursuant to a NSR Permit 0301M9. If this condition was imposed to allow a project to net out of PSD review, then the operational limits cannot be relaxed without the units obtaining a permit as though construction had not yet commenced.[343] But if the units install BACT level controls (SoLoNOx plus SCR), then the burden of obtaining a PSD permit for the units in order to allow both units to produce the needed electricity to operate SCRs may not be substantial. According to EPA's cost spreadsheet for the similar size units to Units 1-6 and 19-20 of the Kutz Canyon Gas Plant, the electricity usage for SCR at the turbines operating at maximum capacity would be approximately 20 kW per hour. Assuming very conservatively that the power for a cooling air skid might double these power needs to 40 kW per hour, the total electricity need for 8 SCR systems (if all combustion turbines being evaluated in this four-factor analysis were equipped with SCR) would very conservatively be 320 kW. If 2400 kW is the maximum capacity of each of Units 19 and 20, this power need reflects 13% of one of the Units 19 or 20 generating units. Given that both generating units are currently not allowed to operate simultaneously under the terms of the permit, it appears that the plant currently has the generating capacity to address worst case electricity needs of SCR systems on each of the eight combustion turbines if the permit was revised to allow for simultaneous operation of both Units 19 and 20.[344]

For all of the reasons discussed above, SCR should not have been excluded from review as a possible NOx control option for Units 1-6 and Units 19-20 at the Kutz Canyon Gas Plant, both by itself and in combination with SoLoNOx.

As discussed above, an SCR installation by itself should be able to reduce emissions to at least 15 ppmv at 15% O_2.[345] That NOx rate reflects a 40% reduction in NOx emissions compared to

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[341] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-5.

[342] Title V Operating Permit P097-R3 for Kutz Canyon Processing Plant at A26, Condition A205.C.

[343] *See* 40 C.F.R. 52.21(r)(4).

[344] As previously stated, the ability to allow both Units 19 and 20 to operate simultaneously
Depends on the reasons that these operational limitations were imposed at Units 19 and 20. If imposed as "synthetic minor" limits or to allow other projects at the facility to net out review, relaxations in those operational restrictions can be allowed if all regulatory requirements including PSD permitting requirements are addressed.

[345] *See* March 2020 NPCA Oil and Gas Four-Factor Report at 75.

the 25 ppm expected NOx rate with SoLoNOx at Units 1-6 and Units 19-20. Further, a 15 ppmv NOx rate reflects a 78% reduction in NOx from Harvest Four Corners' claimed baseline NOx rate for each unit of 67.61 ppm. Based on the fact that the combustion turbines at the Eunice Gas Plant (Units 17A, 18B, 19A, 25A, and 26A) evaluated for SCR by DCP Midstream are of similar size as the Kutz Canyon Units 1-6 and 19-20 combustion turbines, one would expect SCR to have a similar cost effectiveness. As shown in Table 9 above, the cost effectiveness SCR at the DCP Eunice Gas Plant turbines ranged from $2,600/ton to $3,800/ton (assuming a 4.7% interest rate and 25-year life). Thus, one would expect the similar (or same) model turbine and similar size units at Kutz Canyon to have a similar cost effectiveness of SCR to achieve 15 ppmv at 15% O_2, with the exception of units that are not operated at similar levels as the Eunice turbines such as Kutz Canyon Unit 4.

Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[346] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[347] NMED should require Harvest Four Corners to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

C. Clark HRA-8 Two-Stroke Lean-Burn RICE (Units 16-18) of Kutz Canyon Gas Plant

Units 16, 17, and 18 are Clark HRA-8 two-stroke lean-burn refrigerant compressor engines that were constructed in prior to 1973, each with a nameplate capacity of 830 hp and a site-rated capacity of 723 hp.[348] These units each have an hourly NOx limit of 37.1 lb/hr and an annual NOx limit of 162.0 tpy.[349]

1. Evaluation of Baseline NOx Emissions

Harvest Four Corners' four-factor submittal includes baseline NOx emissions (in tpy) based on 2016 emission inventory calculations; no information is provided on operating hours for these engines. NMED should request more information on the units' current hours of operation and

[346] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.
[347] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.
[348] Title V Operating Permit P1097-R3 for Kutz Canyon Processing Plant at A6-A7.
[349] *Id.* at A9.

actual NOx emissions. The baseline emission rates for these units, based on 2016 emission inventory calculations, and the allowable NOx emission rates are shown in the table below.[350]

Table 23 Harvest Four Corners Kutz Canyon Processing Plant 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [tpy]	NOx Baseline Emissions [tpy]
16	723	162.0	151.37
17	723	162.0	89.63
18	723	162.0	87.5

Without information on operating hours it's not possible to know if baseline NOx emissions from units 17 and 18 are lower than permitted rates because these units operated fewer hours in 2016 or if their hourly emission rates were lower.

According to the May 2019 permit application for the Kutz Canyon Processing Plant, NOx emissions for these units were determined, "using stack test and manufacturer's data."[351] The permitted rates for units 17 and 18—that are based on stack test and manufacturer data—are significantly higher than the NOx emission rates that the company's four-factor cost effectiveness analysis is based upon, meaning NOx reductions estimates for the various control options considered may be underestimated if 2016 operation is not reflective of operation in current and future years. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on a more comprehensive estimate of operating hours and emission rates (e.g., in g/hp-hr or hr/yr) expected in 2028.

2. Use of Low Emission Combustion Technology

Harvest Four Corners describes the LEC control technologies for these 2SLB Clark engines as "Clean Burn Technology (CBT)."[352] According to EPA, "[t]he term "clean-burn" technology is a registered trademark of Cooper Energy Systems and refers to engines designed to reduce NOx by operating at high air-to-fuel ratios."[353] It's not entirely clear what specific technologies are being proposed for the Clark engines at the Kutz Canyon Gas Processing Plant. Harvest Four Corners' submittal discusses, generally, the use of high energy ignition system, turbocharger, and AFRC technologies.[354] EPA described LEC retrofit kits designed to achieve extremely lean

[350] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant Appendix B.
[351] *See* May 2019 Permit Revision Application to NSR Permit 0301-M10 for Kutz Canyon Processing Plant, Section 6 Page 2.
[352] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-6.
[353] EPA AP-42 Chapter 3, Section 3.2 (July 2000) at 3.2-2.
[354] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-7.

air-to-fuel ratios – in order to minimize NOx emissions – as encompassing the following specific retrofit technologies:

- Redesign of cylinder head and pistons to improve mixing (on smaller engines)
- Precombustion chamber (on larger engines)
- Turbocharger
- High energy ignition system
- Aftercooler
- Air-to-fuel ration controller (AFRC)[355]

In order to effectively evaluate a company's assessment of LEC a more precise description of LEC technologies, and associated achievable emission rates is needed. Harvest Four Corners states that Clean Burn Technology is estimated to achieve an 80 to 93% reduction in NOx emissions, depending on engine and loading.[356] Harvest Four Corners assumes an 80% NOx reduction in its four-factor analysis for these engines.

The allowable NOx emission rate for these 723 hp engines, at 37.1 lb/hr, is equivalent to 23.3 g/hp-hr. An 80% reduction in NOx emissions would achieve a NOx level of over 4 g/hp-hr. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[357]

For reference, the following sources of information regarding NOx emission rates specific to Clark engines – both uncontrolled and with LEC technology – are provided here:

- EPA's 2000 RICE Update includes NOx emissions test data for specific engines, including Clark Model TLA-6, 2-stroke, lean-burn, 2,000 hp RICE retrofitted with LEC. According to EPA, six engines retrofitted by a third-party vendor had NOx emission rates ranging from 0.8–1.4 g/bhp-hr, with a mean of 1.0 g/bhp-hr.[358]

- An evaluation by a technical group for the Pipeline Research Council International looked at three of the most representative make / models of 2-stroke lean burn compressor engines: (1) 2,250 hp Cooper GMVH-10; (2) 2,000 hp Clark TLA-6; and (3) 2,500 hp Cooper GMW-10. According to a technical report by the Ozone Transport Commission (OTC) describing this evaluation, "[t]he evaluation concluded that there

[355] EPA, Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500-0508, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance, August 2016, Appendix A at 5-3, *available at:* https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0500-0508 [hereinafter referred to as "2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls"].
[356] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-7, citing EPA's 1993 Alternative Control Techniques document for RICE.
[357] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.
[358] EPA 2000 RICE Update at 4-8.

were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring."[359]

For the units at the Kutz Canyon Processing Plant, a controlled NOx emission rate of 2 g/hp-hr from the uncontrolled allowable NOx emission rate (that is based on stack test and manufacturer data) represents a 91% emissions reduction, which is in the range presented in Harvest Four Corners' four-factor submittal of 80 to 93%.

Harvest Four Corners presents cost effectiveness of LEC controls for these units that range from $1,021–$1,767 per ton.[360] The capital cost estimates of $1 million and annual operating and maintenance cost estimates of $40,000 per year are provided by Harvest Four Corners.[361] These capital cost estimates are a little higher, at $186/hp, compared to other capital cost estimates for LEC controls at other similar engines.[362]

Harvest Four Corners assumes NOx emissions reductions of 80% despite stating that the Clean Burn technologies it would employ are capable of reducing NOx emissions up to 93%.[363] And achieving NOx emission rates of 2 g/hp-hr—as shown by other companies in their four-factor analyses for similar engines at similar costs—would correspond to 91% NOx reductions.[364] These greater emissions reductions would result from control of units that are operating at levels closer to permitted levels (which are, again, based on stack test and manufacturer data) and would mean that the LEC controls would be even more cost effective than what is shown in Harvest Four Corners' original four-factor analysis.

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[359] Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, p. 24, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf [hereinafter referred to as "2012 OTC Report"].

[360] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 3-2.

[361] *Id.* Appendix B. Note, these capital cost estimates are in line with other company analyses for similar engines, e.g., Targa's original Four-Factor analysis for Clark HBA-8 engines used capital cost estimates of $950,000. Also, EPA's 2000 RICE Update (p. 5-2) included capital cost estimates for third-party retrofit of a Clark Model HSRA, 2SLB 1,000 hp 8-cylindar engine at a pipeline station of $710,000

[362] *See, e.g.*, November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant cost data for Clark engines at just under $140/hp. *See also* November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant cost data for Clark engines, also under $140/hp.

[363] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-7.

[364] *See* November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 3-3 and November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Monument Gas Plant at 3-2, assuming controlled NOx rates of 2 g/hp-hr for Clark engines.

With respect to the life assumed for LEC control, Harvest Four Corners assumed a 20-year period.[365] This assumption appears to be based on EPA's guidance default for SCR.[366] It's possible that LEC controls can last 25 years, as stated in other cost effectiveness analyses submitted to NMED for LEC controls.[367]

Also, Harvest Four Corners uses an interest rate of 5.5% which is likely high and therefore underestimates annualized costs of control for these engines.[368] As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. Revising Harvest Four Corners cost effectiveness analyses to address some of these issues, including assuming 1) a 4.7% interest rate (instead of 5.5%), 2) a 25-year life of LEC (instead of an assumed 20-year life), and 3) emissions reductions of 91% from baseline emissions, improves cost effectiveness of these controls even further, as shown in the table below.

Table 24. Cost Effectiveness of LEC at Uncontrolled Kutz Canyon Gas Processing Plant Units 16, 17, and 18 to Reduce NO_x Levels to 2 g/hp-hr, Assuming 91% Reductions in NOx Emissions, a 4.7% Interest Rate, and a 25-Year Life of Controls, 2019 $

Unit	Size [hp]	Capital Cost of LEC to Reduce NOx from Baseline Emissions	Annual O&M Costs [2019$]	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (91% NOx Reduction)	Annual Baseline Emissions, tpy	NOx Removed, tpy	Cost Effectiveness of LEC, $/ton
16	723	$1,000,000	$40,000	$134,399	151	138	$790/ton
17	723	$1,000,000	$40,000	$134,399	90	82	$1,334/ton
18	723	$1,000,000	$40,000	$134,399	88	80	$1,367/ton

Harvest Four Corners determined that LEC technology is a technically feasible option for the 2SLB RICE units at the Kutz Canyon Gas Processing Plant and the cost analysis provided in its four-factor analysis, and revised here, confirms this control would be very cost effective. Harvest Four Corners expresses concern that the addition of these controls may be "operationally detrimental" due to the need for a third-party installation. However, no additional specific examples of operational impacts are identified or explained that would necessarily preclude retrofit of these engines. Just because there may be operational issues to

[365] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant Appendix B.
[366] *Id.*
[367] See 2019 Four-Factor submittals for Roswell Compressor Station and Jal No. 3 which both assume 25-year life of controls for LEC.
[368] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant Appendix B.

overcome does not mean that the technology is not feasible or that the resulting emissions reductions are not warranted.

3. Use of SCR

Harvest Four Corners did not evaluate SCR for Units 16, 17, and 18 primarily because it claimed that it was not technically feasible for these engines.[369] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[370]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[371] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[372] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of \$2,400/ton to \$2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

IX. El Paso Natural Gas Company LLC - Pecos River Compressor Station

The Pecos River Compressor Station is a natural gas compressor station located approximately 12 miles south/southeast of Malaga, New Mexico in Eddy County. It is owned/operated by El

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[369] *Id.* at 2-8.
[370] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[371] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[372] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

Paso Natural Gas Company (EPNG). The facility consists of three GE Frame 3 Regenerative Cycle Turbines that each have a capacity of 7,150 hp.[373]

In EPNG's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Natural Gas-Fired Regenerative Cycle Turbine (Units A-01, A-02, and A-03)[374]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[375] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

EPNG used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[376] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[377] The current bank prime rate is 3.25%.[378] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[379] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[380] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

[373] Title V Operating Permit P129R3 for Pecos River Compressor Station at 3.
[374] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 1-2.
[375] *Id.*
[376] *Id.* at 8-6.
[377] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[378] https://www.federalreserve.gov/releases/h15/.
[379] https://fred.stlouisfed.org/series/DPRIME.
[380] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

B. GE Regenerative Cycle Turbines (Units A-01, A-02, and A-03) of Pecos River Compressor Station

As stated above, the three turbines evaluated for controls are GE Frame 3 Regenerative Cycle Turbines with capacity of 7,150 hp. These units were all manufactured in 1953.[381] Under the terms of the permit, the units are each subject to the following hourly and annual emission limits of NOx: 53.1 lb/hr and 232.6 tpy.[382]

EPNG evaluated one control option for these turbines aside from the good combustion practices which the company indicated were currently being utilized at the units. The other combustion control type of controls considered by EPNG included a Lean Head End (LHE) combustion liner, dry low NOx combustors, water/steam injection, but El Paso claimed that based on communications with GE, none of these controls were an option for the Pecos River Compressor Station turbines.[383] Thus, the company only evaluated SCR for the turbines. The following provides comments on the company's four-factor analysis of SCR.

1. Baseline Emissions for the Units A-01, A-02, and A-03 Combustion Turbines.

EPNG states that its cost effectiveness analyses for SCR were based on actual emissions using 2016 stack test data and actual hours of operation from the 2016 emission inventory submittal.[384] In its cost data sheets in Section 8.0 of its four-factor analysis, the company provided summaries of the 2016 test data and the 2016 annual NOx tons per year from each unit, from which the actual operating hours could then be calculated.[385] NMED and EPNG should review other stack tests for these units to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on an estimate of emissions expected in 2028.

2. Evaluation of SCR for the Regenerative Cycle Turbines at Pecos River Compressor Station

EPNG evaluated SCR to achieve 70% reduction in NOx emissions, assuming a 20-year life of SCR.[386] With respect to the lifetime of an SCR, EPA's Control Cost Manual indicates that the life of an SCR at a gas turbine used in an industrial setting like a compressor station.[387] Thus, to be consistent with EPA's current Control Cost Manual chapter on SCR, a 25-year life of SCR should have been assumed.

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[381] Title V Operating Permit P129R3 for Pecos River Compressor Station at 5.
[382] *Id.*
[383] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 3-1.
[384] *Id.* at 3-1.
[385] *Id.* at Appendices C and D.
[386] *Id.*, Section 8.0 (at pdf page 31, 36, and 41.
[387] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

EPNG only assumed 70% control with SCR at Units A-01, A-02, and A-03 and cites to an older EPA Fact Sheet on SCR.[388] A review of that EPA fact sheet, which appears to be from 2003, shows that EPA assumed SCR could achieve 70-90% NOx control, and EPA assumed 85% control in its example cost effectiveness analysis of the 2003 Fact Sheet. In EPA's June 2019 updated chapter on selective catalytic reduction in its Control Cost Manual, EPA states that "[t]heoretically, SCR systems can be designed for NOx removal efficiencies [of] close to 100 percent. In practice, commercial coal-, oil-, and natural gas-fired SCR systems are often designed to meet control targets of over 90 percent."[389] EPNG did not provide any other justification for assuming only 70% control with SCR at the Pecos River Compressor station turbines. Indeed, ninety percent control has been the benchmark of SCR NOx removal efficiency expected with SCR including at natural gas-fired combustion turbines.[390] As discussed in NPCA's Oil and Gas Four-Factor Report, in a 2000 analysis of SCR cost effectiveness from an uncontrolled gas turbine, NESCAUM estimated that a 15 ppmvd NOx rate reflective of 90% NOx control (from uncontrolled NOx rates) could be achieved with SCR.[391]

EPNG used the SCR cost spreadsheet that EPA has made available with the Control Cost Manual to estimate SCR costs for its combustion turbines.[392] However, EPNG stated that the exhaust system would require significant modifications to install the catalyst, requiring the stack to be moved and additional ducting.[393] EPNG also states that it believes there is insufficient room within the existing building that houses the turbines, and thus has included costs to modify the turbine housing in the cost analysis.[394] Presumably, to account for some of this, EPNG applied a 1.5 retrofit factor in EPA's SCR cost spreadsheet, and also EPNG also included an additional $2.5 million would be required per combustion turbine for building modifications. However, as previously stated above, there have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints and retrofit difficulties. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new foundations to make way for the SCR reactor.[395] EPA's SCR cost spreadsheet has an option to indicate whether the SCR installation is a new installation or a retrofit, and SPNG selected "retrofit." EPA's SCR chapter in its Control Cost Manual already provides for a 25% increase in cost above the cost of SCR at a new greenfield coal-fired boiler,

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[388] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 3-1.

[389] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 5.

[390] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand Curve Reset, prepared for New York Independent System Operator, Inc., at 5 and at 11-12, available at: http://files.brattle.com/files/7644_independent_evaluation_of_scr_systems_for_frametype_combustion_turbines.pdf.

[391] NESCAUM 2000 Status Report at III-21 through III-24 and at III-40 (see references 11, 16, 9, 14, and 15).

[392] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 3-1.

[393] *Id.*

[394] Id.

[395] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, , available at https://www.onepetro.org/conference-paper/SPE-66501-MS.

which is reflected in EPA's SCR cost spreadsheet, because EPA's spreadsheet calls for use of a "0.8" retrofit factor for an SCR installation at a new facility and a "1" retrofit factor for an average SCR retrofit.[396] Further, given that most gas turbines that have retrofitted an SCR reactor likely were not planned or designed for an SCR reactor to be installed, the average retrofit costs that EPA's SCR cost spreadsheet calculates likely take into account some of the difficulties like the need to move the exhaust stack to install the SCR, which would be required for most if into all SCR retrofits to gas turbines.[397] Thus, EPNG was not justified in using both a 1.5 retrofit factor in the SCR cost spreadsheet and also adding $2.5 million in capital costs per unit for compressor building modifications.

With respect to the compressor building modifications, there is one entry made by EPNG into the EPA cost spreadsheet that ultimately defines the size of the SCR reactor, and that is the "base case fuel gas volumetric flow rate factor" which is in terms of ft^3/min-MMBtu/hr. EPNG used a fuel gas volumetric flow rate factor of 35,103.70 ft^3/min-MMBtu/hr for Unit A-01, 50,483.81 ft^3/min-MMBtu/hr for Unit A-02, and 45,807.42 ft^3/min-MMBtu/hr for Unit A-03, which they state is "[c]alculated based on the estimated actual annual fuel consumption and maximum heat input rate."[398] These numbers seem very high in comparison to the values EPA uses for coal-fired boilers for which EPA defines as a constant for fuel type regardless of unit size or actual gas throughput.[399] EPNG's fuel gas volumetric flow rate factors for each combustion turbine are roughly a factor of 100 higher than the fuel gas volumetric flow rate factors used by EPA in its SCR cost spreadsheet for coal-fired boilers. Given that the fuel gas volumetric flow rate factor is used to determine the size of SCR reactor required, it is imperative that NMED ensure that an accurate fuel gas volumetric flow rate factor for natural gas-fired combustion turbines is used in the SCR cost spreadsheet. Presumably, EPNG relied on the reactor size calculations of the spreadsheet to estimate the cost of $2.5 million per SCR installation for modifying the compressor building.

With respect to the cost to modify the compressor building, it appears that EPNG included the $2.5 million per SCR to modify the compressor building with the capital costs of SCR in determining total annual costs of the control.[400] This reflects a 65% increase in the capital cost of SCR that was calculated using a 1.5 retrofit factor. However, while the life of the SCR might be only 25 years, the life of the modifications to the compressor building would likely last as long as the compressor station is in operation, which has been 65 years so far "without any significant deterioration in operating efficiency [of the combustion turbines],[401] and EPNG anticipates that the life of the turbines will be longer than the SCR. Thus, EPNG's approach significantly increases the capital cost and thus the cost effectiveness of SCR for building

[396] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 66.
[397] *See* EPA Control Cost Manual, Section 1, Chapter 2 – Cost Estimation: Concepts and Methodology, at 27.
[398] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at pdf page 32, pdf page 37, and pdf page 42.
[399] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 59, Table 2.6.
[400] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 2-6.
[401] *Id.* at 5-2.

modifications that will have a useful life much longer than the 25 years that EPA assumes for SCRs at industrial facilities.

To attempt to address some of these issues, as well as to revise the cost effectiveness to reflect a 4.7% interest rate and a 25-year life, EPA's SCR cost spreadsheets were used to calculate SCR cost to meet a NOx emission rate of 15 ppmv (reflective of 82 to 86% NOx removal at the Pecos River turbines)[402] assuming a 25-year life and a 4.7% interest rate. No retrofit factor was used in EPA's cost spreadsheets for the reasons previously described, but an analysis was done adding in the company's projected $2.5 million capital cost to the total SCR capital costs. Although the life of the modified compressor building would be much longer than 25 years, the $2.5 million was amortized at the same 25-year life as the SCR. No other changes were made to any of EPNG's inputs to the SCR spreadsheet. The results of these analyses are provided below.

Table 25. Cost Effectiveness of SCR at Pecos River Compressor Station Units A-01, A-02, and A-03 Combustion Turbines, Using a 25-year Life, 4.7% Interest Rate, Retrofit Factor of 1, and EPNG's Assumptions for all Other Inputs

Unit	Assumed NOx Removal Efficiency to meet 15 ppm NOx rate	Capital Cost of SCR (2018 $)	Annual O&M Costs	NOx Removed from 2016 Baseline, tpy	Cost Effectiveness of SCR (2018 $), $/ton	Cost Effectiveness of SCR with Building Modifications (2018 $), $/ton
A-01	82%	$2,535,199	$33,780	42	$5,007/ton	$9,104/ton
A-02	86%	$2,535,199	$43,109	82	$2,676/ton	$4,775/ton
A-03	86%	$2,535,199	$48,533	101	$2,230/ton	$3,934/ton

The above table provides cost effectiveness for SCR by itself at Units A-01, A-02, and A-03 as well as SCR plus the EPNG's estimated $2.5 million capital cost per SCR to modify the compressor building. As the table shows, including EPNG's estimated cost to modify the compressor building for each SCR installation significantly increases the cost effectiveness of SCR. For the reasons stated above, it is imperative that NMED ensure that the costs to modify the compressor building were appropriately estimated. Regardless, for at least Units A-02 and A-03 which operated more than Unit A-01 in 2016, SCR should still be considered cost effective even with $2.5 million in costs per SCR to modify the building. And if 2016 operating hours were lower than typical operation for Unit A-03, SCR should be considered cost effective for that unit as well.

[402] This was determined by converting EPNG's stated uncontrolled lb/MMBtu NOx rates to ppm NOx rates using the conversions of EPA's 1993 ACT for Gas Turbines (*See* EPA, 1993 ACTfor Gas Turbines at Appendix A which has conversion equations for natural gas-fired combustion turbines) and determining the percent NOx reduction efficiency to achieve a 15 ppmv NOx limit (equivalent to ~0.060 lb/MMBtu).

EPNG expressed concerns with the ammonia reagent used in an SCR system.[403] As discussed in the NPCA Oil and Gas Four-Factor Report, the primary concerns with ammonia releases are when anhydrous ammonia is used for the reagent.[404] EPNG assumed 29% aqueous ammonia in its SCR analyses.[405] When aqueous ammonia, or urea, is used, the hazards from transporting and storing pressurized ammonia don't apply. SCR has been installed at numerous industrial facilities across the U.S. There are well-established protocols and procedures for safely transporting, storing, and using anhydrous ammonia at facilities that use that reagent in their SCR systems.

X. DCP Midstream - Linam Ranch Gas Plant

The Linam Ranch Gas Plant is a natural gas processing plant located about seven miles west of Hobbs, New Mexico in Lea County. The plant is owned/operated by DCP Midstream LP. According to the Title V permit for the plant, the facility processes natural gas by removing hydrogen sulfide, water, and carbon dioxide from field gas and separates natural gas liquids from the field gas stream.[406] NMED's Statement of Basis for the plant's Title V permit describes the plant as follows: "The plant consists of an Inlet Receiving System, Amine Treater, Acid Gas Injection Well, Inlet Compression and Dehydration System, Cryogenic/Turbo Expander Plant with external Propane Refrigeration, Residual Compression, and Product Sales for Residue Gas, NGL Liquids, Stabilized Oil, Slop Oil, and Molten Liquid Sulfur."[407] The plant include Fuel Gas Systems, Instrument and Starting Air Systems, a Heat Medium (Hot Oil) System, Cooling Towers, Process Flare, Acid Gas Flare, and Drain Systems. Processing operations at the plant include chemical reaction processes, thermodynamic processes, and physical processes."[408]

According to the Title V permit, the Linam Ranch Gas Plant includes several 2-stroke lean burn RICE, several natural gas-fired turbines, boilers, a heater, gas sweetening equipment (amine unit, sulfur recovery unit (SRU) incinerator, acid gas and SRU flares), and other emission units.[409] In DCP Midstream's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Clark TLA-6 2-stroke lean-burn RICE: Units 6-11
- Solar Centaur Turbines: Units 29, 30, 31, and 32B.[410]

[403] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 5-1.
[404] March 2020 NPCA Oil and Gas Four-Factor Report at 80. *See also* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 15.
[405] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at pdf page 32, pdf page 37, and pdf page 42.
[406] Title V Operating Permit P094-R2 for Linam Ranch Gas Plant at 3.
[407] NMED Statement of Basis – Narrative, Title V Permit, Linam Ranch Gas Plant, March 2015, at 1.
[408] NMED Statement of Basis – Narrative, Title V Permit, for Permit Nos. 0044-M-10-M10R6 and P086-R3, at 1.
[409] Title V Operating Permit P094-R2 for Linam Ranch Gas Plant at 7-8.
[410] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Linam Ranch Gas Plant at 1-2.

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[411] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

DCP Midstream used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[412] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[413] The current bank prime rate is 3.25%.[414] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[415] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[416] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

B. Clark TLA Two-Stroke Lean Burn RICE (Units 6-11) of the Linam Ranch Gas Plant

Units 6 and 7 are Clark TLA-6 two-stroke lean-burn RICE that were constructed in 1974, each with a capacity of 2,000 hp.[417] Units 6 and 7 each have an hourly NOx limit of 39.3 lb/hr; units 6-11 have a combined annual NOx limit of 566 tpy.[418]

Units 8 through 11 are Clark HBA-6 two-stroke lean-burn RICE that were constructed in 1951, each with a capacity of 1,267 hp.[419] Units 8 through 11 each have an hourly NOx limit of 47.5 lb/hr; units 6-11 have a combined annual NOx limit of 566 tpy.[420]

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[411] *Id.*
[412] *Id.* at Section 8.0 Supporting Documentation.
[413] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[414] https://www.federalreserve.gov/releases/h15/.
[415] https://fred.stlouisfed.org/series/DPRIME.
[416] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.
[417] Title V Operating Permit P094-R2 for Linam Ranch Gas Plant at 7.
[418] *Id.* at 9.
[419] *Id.* at 7.
[420] *Id.* at 9.

1. Use of Low Emission Combustion Technology

DCP Midstream determined that, "…clean burn technology retrofits are physically possible yet deemed technically infeasible for the engines at Linam. The aforementioned available clean burn control technologies are incapable of being retrofit on the existing 70-year-old engines on site."[421] It's true that Units 8 through 11 are 69 years old but units 6 and 7 are newer units and, in fact, units of similar ages to all of these units at Linam Ranch have demonstrated LEC retrofit technology to reduce NOx emissions. For example, Targa's Eunice and Monument gas plants operate Clark engines of similar vintage to the ones at Linam Ranch and submitted four-factor analyses to NMED for Clean Burn technology retrofits, which Targa deemed to be feasible control options.[422]

More generally, the following additional information regarding NOx emission rates specific to Clark TLA model engines – both uncontrolled and with LEC technology – are provided here:

- EPA's 2000 RICE Update includes NOx emissions test data for specific engines, including Clark Model TLA-6, 2-stroke, lean-burn, 2,000 hp RICE retrofitted with LEC. According to EPA, six engines retrofitted by a third-party vendor had NOx emission rates ranging from 0.8–1.4 g/bhp-hr, with a mean of 1.0 g/bhp-hr.[423]

- An evaluation by a technical group for the Pipeline Research Council International looked at three of the most representative make / models of 2-stroke lean burn compressor engines: (1) 2,250 hp Cooper GMVH-10; (2) 2,000 hp Clark TLA-6; and (3) 2,500 hp Cooper GMW-10. According to a technical report by the Ozone Transport Commission (OTC) describing this evaluation, "[t]he evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring."[424]

- In 2002, EPA collected data on emission rates of lean burn engines that have been retrofitted with LEC, including data from several state agencies for specific engine

[421] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Linam Ranch Gas Plant at 2-9.
[422] Targa's Eunice Gas Plant operates several Clark BA-6 and HBA-T8 2SLB RICE constructed in 1984 and capable of being retrofit with LEC technology. Targa's Monument Gas Plant operates several Clark RA-6, RA-8, and HRA-8 2SLB RICE constructed in 1956 and 1969 and capable of being retrofit with LEC technology.
[423] EPA 2000 RICE Update at 4-8.
[424] Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, p. 24, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf [hereinafter referred to as "2012 OTC Report"].

models.[425] Test results for 20 Clark TLA engines ranged from 0.4 to 2.9 g/hp-hr, with an average controlled NOx rate of 1.5 g/hp-hr.[426]

The above references don't specify the age of the engines retrofit with LEC technology but NMED should require DCP Midstream to further explore additional third-party vendor options for retrofitting these units.

A recent Interstate Natural Gas Association of America (INGAA) Report provides some information on Clark TLA engine stock components and retrofit modification / upgrade options.[427] Examples from this report include: upgrading stock turbocharger and stock intercooler systems; upgrading stock low pressure direct fuel systems to high pressure fuel injection and control systems; and upgrading controls for the stock fuel system.[428] Based on the information in this report, Clark TLA model engines come equipped with a single turbo, an intercooler system, and a low pressure direct fuel system. The INGAA report evaluated controls for various regulatory scenarios that would achieve NOx emission levels in the 1–3 g/hp-hr range.[429]

LEC retrofit costs specific to Clark TLA model engines are reported in the INGAA report, ranging from \$300–\$600 per hp, for upgrades to the scavenging, intercooler, and fuel systems.[430] The INGAA report doesn't specify what year the cost data are from so we assume it reflects the timeframe of the report, or 2017\$. Using these cost data, we can estimate the cost effectiveness of retrofitting Units 6 through 11 at the Linam Gas Plant. Retrofit cost estimates using INGAA's cost estimate would range from \$600,000–\$1,200,000 for the 2,000 hp units 6 and 7 and \$380,000–\$760,200 for the 1,267 hp units 8 through 11, in 2017\$. Using the Chemical Engineering Plant Cost Indices, these costs would increase to \$640,000–\$1,275,000 and \$400,000–\$800,000, in 2018\$.[431] It's not clear if operating costs are included in these INGAA cost estimates; to be conservative, annual operating costs of the LEC controls are assumed to be 15% of capital costs.[432]

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[425] *See* EPA Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call (October 2003) at 15, *available at:* http://www.valleyair.org/workshops/postings/2011/8-18-11-rule4702/R4702%20APPF.pdf

[426] *Id.* Table 4.

[427] INGAA, Report No. 2016-6, *Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOx Control for Natural Gas Transmission and Storage Compressor Drivers* (December 2017), *available at:* https://www.ingaa.org/File.aspx?id=33789.

[428] *Id. See, e.g.,* Table 6 at 18.

[429] *Id.* at 23.

[430] *Id.*

[431] Based on multiplying the cost estimate from the 2017 INGAA report by the ratio of the CEPCI indices for 2018 to 2017 (603.1/567.5).

[432] This assumption is consistent with cost data provided for the October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, however it results in much higher O&M costs than those used in Targa's (Eunice, Monument, and Saunders Gas Plants) and Harvest Four Corners' (Kutz Canyon Gas Plant) four-factor analyses—which ranged from \$40,000/yr to \$100,000/yr—and than those used for ETC Texas Pipeline's Jal No. 3 Gas Plant, which assumed O&M costs would be 13% of capital costs.

EPA has examined source test data from large natural gas-fired lean burn engines and has affirmed that these data support an uncontrolled emission rate from these engines, generally, of 16.8 g/hp-hr.[433] More specifically, these source test data include individual data for three Clark TLA engines with uncontrolled emission rates of 16 g/hp-hr and two Clark TLA-10 engines with uncontrolled emission rates of 7 g/hp-hr.[434] The allowable hourly NOx emission rates for the units at Linam Ranch are equivalent to 9 g/hp-hr (for units 6 and 7) and 17 g/hp-hr for units 8 through 11. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[435] Retrofitting LEC technology on the units at Linam Ranch to achieve a controlled NOx rate of 2 g/hp-hr reflects a 78-88% emissions reduction from the sources' allowable NOx rates. Baseline NOx emissions for these units at Linam Ranch were not provided in DCP Midstream's four-factor submittal.
The cost effectiveness of retrofitting these engines with LEC to meet a 2 g/hp-hr NOx emissions rate, based on uncontrolled emission rates (no higher than what is permitted for this source), is presented in the table below. Since the operating schedule for these engines at the Linam Gas Plant is unknown we present cost effectiveness for 2,000 and 4,000 operating hours per year; the permitted annual NOx emission rate cap for these units of 566 tons per year indicates that the units likely wouldn't operate much more than 4,000 hours per year, on average. Note, this analysis uses an interest rate of 4.7%, reflective of current and likely near future interest rates.[436] Further note, the LEC controls are assumed to last 25 years, consistent with other cost effectiveness analyses submitted to NMED for LEC controls.[437]

[433] *See* EPA Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call (October 2003) at 5, *available at:* http://www.valleyair.org/workshops/postings/2011/8-18-11-rule4702/R4702%20APPF.pdf.
[434] *Id*. at 6 and 7.
[435] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.
[436] As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.
[437] See 2019 Four-Factor submittals for Roswell Compressor Station and Jal No. 3 which both assume 25-year life of controls for LEC.

Table 26. Cost Effectiveness of LEC at Uncontrolled Linam Gas Plant Units 6 through 11 to Reduce NO_x Levels to 2 g/hp-hr, Assuming a 4.7% Interest Rate and a 25-Year Life, 2018$

Unit	Capital Cost of LEC to Reduce NOx from Uncontrolled Rate	Annual O&M Costs (assume 15% of Capital Costs)	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (78-88% NOx Reduction)	NOx Removed, tpy operating 2,000 hr/yr	Cost Effectiveness of LEC operating 2,000 hr/yr, $/ton	NOx Removed, tpy operating 4,000 hr/yr	Cost Effectiveness of LEC operating 4,000 hr/yr, $/ton
6	$640,000–$1,275,000	$96,000–$191,000	$140,000–$280,000	31	$4,521/ton—$9,042/ton	62	$2,260/ton–$4,521/ton
7	$640,000–$1,275,000	$96,000–$191,000	$140,000–$280,000	31	$4,521/ton—$9,042/ton	62	$2,260/ton–$4,521/ton
8	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	41	$2,138/ton—$4,277/ton	83	$1,069/ton–$2,138/ton
9	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	41	$2,138/ton—$4,277/ton	83	$1,069/ton–$2,138/ton
10	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	41	$2,138/ton—$4,277/ton	83	$1,069/ton–$2,138/ton
11	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	41	$2,138/ton—$4,277/ton	83	$1,069/ton–$2,138/ton

LEC at these units would be even more cost effective than what is shown if retrofits at these engines could meet even lower NOx emission levels, less than 2 g/hp-hr. DCP Midstream indicated that retrofitting engines at the Linam Gas Plant is physically possible and NMED should require that the company solicit specific vendor quotes in order to assess the cost effectiveness of reducing NOx emissions from these engines, as has been done by other companies in New Mexico with similar engines.

2. Use of SCR

DCP Midstream did not evaluate SCR for Units 6 through 11 primarily because it claimed that it was not technically feasible for these engines.[438] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be

[438] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Linam Ranch Gas Plant at 2-9.

summarily dismissed as not feasible for these engines, particularly because DCP Midstream has not found LEC to be a cost effective NOx reduction strategy for these units.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[439]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[440] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[441] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

C. Solar Centaur Natural Gas-Fired Combustion Turbines (Units 29, 30, 31, and 32B) of the Linam Ranch Gas Plant.

The combustion turbines evaluated at the Linam Ranch Gas Plant are Solar combustion turbines of the following models, horsepower capacities, and manufacture date:[442]

Unit 29	Solar T-70	77.6 MMBtu/hr	1995
Unit 30	Solar Taurus T-70	73.95 MMBtu/hr	1995
Unit 31	Solar T4700	36.8 MMBtu/hr	1995
Unit 32B	Solar T4000	36.2 MMBtu/hr	1979

The units are all subject to NOx limits in 40 C.F.R. Part 60, Subpart GG, but those specific limits are not detailed in the Title V permit.[443] Under the terms of the permit, the units are also subject to the following hourly and annual emission limits of NOx.

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[439] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[440] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[441] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[442] *See* Title V Operating Permit P094-R2 for Linam Ranch Gas Plant at 8.
[443] *Id.* at 10.

Table 27. Limits from DCP Midstream Title V Permit for the Linam Ranch Plant Combustion Turbines[444]

Combustion Turbine Unit ID	NOx limit, lb/hr	NOx limit, tpy
29	11.8	51.8
30	11.3	49.3
31	26.0	114
32B	23.7	103.9

DCP Midstream evaluated two control options for these combustion turbines: Solar's SoLoNOx combustion system and SCR.

1. Baseline Emissions for Units 29, 30, 31, and 32B.

DCP Midstream states that its cost effectiveness analyses for SoLoNOx and SCR were based on 2016 turbine operating hours multiplied by the permitted potential to emit rate (lb/hr).[445] However, the company did not provide the operating hours or this calculation of 2016 emissions in its four-factor analysis. The company also provided analyses of cost effectiveness of controls "[u]sing the actual emissions testing data (NSPS KKKK) for these turbines, rather than [potential to emit]."[446] However, the company provided no data in its four-factor analyses as to what the actual emission testing results were. Further confusing the matter is that, based on a review of the permit, the turbines are not subject to NSPS KKKK. Instead, all of the units are subject to NSPS Subpart GG.[447] A review of Title V permit application data for the Linam Ranch Gas Plant on the NMED's Emissions Analysis Tool did not find any other emissions testing data available for these units. NMED must make available whatever test data is being relied on to reflect actual emissions of these five combustion turbines if NMED intends to rely on the cost effectiveness analyses provided in a footnote of DCP Midstream's four-factor analysis. NMED should present information on the test data so the circumstances of the stack tests can be reviewed.

According to DCP Midstream's four-factor analysis, its 2016 emission inventory is based on its actual operating hours multiplied by its hourly NOx emission limit.[448] Given that this is how DCP Midstream reports actual emissions for the combustion turbines to NMED and in the absence of testing documentation to ensure that the test data DCP relies on for its alternative baseline analysis reflects actual emissions at all levels of operation of the combustion turbines, it seems most appropriate to use the data that DCP has been using for its emission inventory. NMED should require that DCP identify the operating hours of each unit that it has assumed for the combustion turbines.

[444] *Id.* at 9.
[445] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Linam Ranch Gas Plant at 3-11, fn 23.
[446] *Id.*
[447] Title V Operating Permit P094-R2 for DCP Midstream Linam Ranch Gas Plant at 6, Table 103.A.
[448] *Id.* at 3-11.

2. Evaluation of SoLoNOx for the Combustion Turbines at 29, 30, 31, and 32B.

DCP Midstream states that SoLoNOx can achieve an "overall reduction efficiency of 55%-80%...for the turbines located at this facility using this technology in comparison to permitted [potential to emit]."[449] Specifically, DCP Midstream evaluated SoLoNOx to meet a 15 ppm NOx rate at Units 29 and 30 and a 25 ppm NOx rate at Units 31 and 32B.[450]

In terms of the life of SoLoNOx controls in the cost effectiveness analyses, DCP's analysis assumed a 20 year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[451] In the table below, DCP Midstream's cost effectiveness analyses of SoLoNOx were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate.

Table 28. Revised Cost Effectiveness of SoLoNOx at Units 29, 30, 31 and 32B of the DCP Midstream Linam Ranch Gas Plant, to Reflect a 4.7% Interest Rate and a 25 Year Life

Unit	DCP's Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	DCP's Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25 Year Life
29	$605,743	$21,278/ton	$602,950	$20,642/ton
30	$618,799	$23,829/ton	$616,006	$23,720/ton
31	$269,048	$3,100/ton	$248,594	$2,865/ton
32B	$268,805	$12,765/ton	$248,151	$11,794/ton

The cost effectiveness of SoLoNOx at Units 29 and 30 are very high, because according to DCP Midstream's four-factor submittal, the units' current NOx rates are 33-35 ppm, and thus SoLoNOx to reduce the units' NOx emissions to 15 ppm will only reduce emissions by 55-57%. For Unit 31, SoLoNOx is much more cost effective at $2,865/ton, as the company's four-factor submittal shows that SoLoNOx at Unit 31 would reduce NOx by 78%. For Unit 32B, the cost effectiveness is higher despite SoLoNOx being projected to reduce NOx by 76% because the unit had low actual emissions in 2016 (which appears to be due to low operating hours). NMED should ensure that the 2016 emissions and operational data that is being relied on for the cost effectiveness analyses is reflective of historical operations and projected operations in 2028 before discounting a highly effective control as not cost effective.

[449] *Id.* at 2-4.

[450] *Id.* at pdf page 29, pdf page 34, pdf page 39, and pdf page 44.

[451] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

3. Evaluation of SCR for Units 29, 30, 31, and 32B of the DCP Midstream Linam Ranch Gas Plant.

DCP Midstream evaluated SCR as a technically feasible control option for the Solar Centaur gas combustion turbines of Units 29, 30, 31, and 32B of the DCP Midstream Linam Ranch Gas Plant. DCP Midstream used EPA's SCR cost spreadsheet made available with EPA's Control Cost Manual.[452]

DCP Midstream only assumed 70% control could be achieved with SCR at Units 29, 30, 31, and 32B, even though the company indicated that SCR could achieve up to 90% control.[453] As presented NPCA's Oil and Gas Four-Factor Report, NESCAUM assumed 90% control with SCR in its 2000 Status Report to control small gas turbines down to 15 ppmv.[454] However, for Units 29 and 30, a 15 ppm NOx rate with SCR only reflects 55-57% control. As discussed in Section I.C.2 above, NOx rates as low as 3.75 ppm have been permitted for gas turbines with SoLoNOx and SCR.[455] Thus, to reflect the capabilities of SCR at Units 29 and 30, a much lower NOx emissions rate should have been evaluated for these units. For this report, the EPA's SCR cost spreadsheet was thus used with almost all of the same data inputs as used by DCP Midstream, but assuming a NOx rate equivalent to about an 85% NOx reduction would be met at the units (approximately a 5 ppm NOx emission rate at Units 29 and 30 and 15 ppmv NOx emission rate at Units 31 and 32B). The only other changes made to DCP's SCR spreadsheet inputs were to assume a longer life of the SCR of 25-years[456] and a 4.7% interest rate (instead of DCP's assumed 20-year life of SCR and 5.5% interest rate). The table below provide the estimated cost effectiveness of SCR to achieve 85-87% control at Units 29, 30, 31, and 32B of the DCP Midstream Linam Ranch Gas Plant.

[452] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Linam Ranch Gas Plant at 3-12.
[453] *Id.* at 2-6.
[454] NPCA March 2020 Oil and Gas Four-Factor Report at 74-75. *See also* NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15), available at http://www.nescaum.org/documents/nox-2000.pdf/view.
[455] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.
[456] EPA's Control Cost Manual indicates that SCR at industrial units has a life of 25-years. *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

Table 29. Cost Effectiveness of SCR to Achieve ~85% NOx Reduction (5 ppmv at Units 19 and 20 and 15 ppmv at Units 21 and 22B) at the Linam Ranch Gas Plant, Assuming a 25-Year Life of SCR and a 4.7% Interest Rate

Linam Ranch Unit #	Capital Cost of SCR	Annual Operational and Maintenance Costs of SCR	Annualized Cost of SCR to Achieve 85-87% NOx control	NOx Emission Reductions, tpy	Cost Effectiveness of SCR to Achieve 85-87% Control (at 4.5% interest rate and 25 year life)
19	$3,029,516	$50,364	$261,605	44	$5,991/ton
20	$2,935,376	$47,267	$252,025	39	$6,395/ton
21	$1,864,898	$34,660	$165,705	97	$1,706/ton
22B	$1,845,408	$18,703	$148,406	24	$6,195/ton

As shown by a comparison of Table 29 to Table 28 above, SCR at the Linam Ranch Gas Plant Units 19, 20, 21, and 22B is actually more cost effective than SoLoNOx at the units and SCR can achieve greater levels of NOx reductions. SCR could be even more cost effective if there are opportunities to share an SCR between two or more combustion turbines.
Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[457] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[458] NMED should require DCP Midstream to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

XI. ETC Texas Pipeline – Jal No. 3 Gas Plant

The ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant is located in Lea County. NMED has described the facility processes as follows:

> The function of the facility is to treat and process natural gas. The facility consists of natural gas compression units, amine-sweetening units, a sulfur unit, an acid

[457] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.

[458] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.

gas reinjection system, various storage tanks, fugitive emissions, and three flares.[459]

According to the permit, the plant includes several 2-stroke and 4-stroke lean-burn reciprocating internal combustion engines (RICE), boilers, heaters, amine sweetening units, vapor recover unit and thermal oxidizer, flares, and tanks.[460] In ETC Texas Pipeline's four-factor submittal, the company evaluated air pollution controls for the following emission units:

- Cooper-Bessemer 2SLB RICE GMV-10T5: Units 4A and 5A.[461]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[462] The following provides a review of the company's four-factor analyses.

A. Units 4A and 5A: Cooper-Bessemer GMV-10T5 2-Stroke Lean-Burn RICE

Units 4A and 5A are two-stroke lean-burn RICE that were constructed in 1948, each with a capacity of 1,100 hp.[463] The units each have an hourly NOx limit of 27.9 lb/hr and an annual NOx limit of 122.0 tpy.[464] The operating hours for these units, based on 2016 emissions inventory data are 560 hours per year for unit 4A and 4,290 hours per year for units 5A.[465]

1. Use of Low Emission Combustion Technology

ETC Texas Pipeline describes units 1A, 2A, and 3A as the same Cooper-Bessemer GMV-10T5 engines but currently operating with low emission control technology.[466] These engines were retrofit in 2007 by Cameron Compression Systems including new power cylinder heads, gas ignitors, a high efficiency turbocharger, and guaranteeing a controlled NOx emission rate of 2 g/hp-hr.[467]

ETC Texas Pipeline assumes a controlled NOx emission rate from LEC retrofits on units 4A and 5A of 1 g/hp-hr and estimates this represents an 81–89% reduction from baseline NOx emission rates that are based on the 2016 emissions inventory.[468] The permitted maximum hourly NOx emission rate of 27.9 lb/hr for these units is significantly higher than the 2016 emissions

[459] Title V Operating Permit P090-R3 for Jal #3 Gas Plant at A3.
[460] *Id.* at A7–A9.
[461] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at 2 and Appendix B.
[462] *Id.* at 2.
[463] Title V Operating Permit P090-R3 for Jal #3 Gas Plant at A7.
[464] *Id.* at A10.
[465] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant Appendix B.
[466] *Id.* at 2.
[467] *Id.* at 4 and Appendix A (*see* pdf page 26).
[468] *Id.* at 5.

inventory data used for baseline emissions, especially for unit 5A. The allowable hourly NOx emission rate is equivalent to 11.5 g/hp-hr for these 1,100 hp engines. The source's Title V renewal application provided details on the basis for the uncontrolled NOx emission rate as stack test data, with data provided for all five Cooper-Bessemer GMV-10TF engines. The stack test data for units 4A and 5A are shown in the table below, along with the baseline emissions used in the four-factor analysis (that are based on 2016 emissions inventory calculations):

Table 30. ETC Texas Pipeline Jal No. 3 Gas Plant 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Stack Test Data from Title V Permit Application [g/hp-hr]	NOx Baseline Emissions from August 2016 EI [g/hp-hr]
A4	1,100	27.9	11.5	6.2–6.8	9.4
A5	1,100	27.9	11.5	7.2–8.2	5.1

Assuming a controlled NOx emission rate for LEC of 1 g/hp-hr, emissions reductions range from 84–89% for unit A4 and from 81–88% for units A5. ETC Texas Pipeline assumed 89% control for unit A4 and 81% control for unit A5. If unit A5 operates at a higher emission rate than in 2016—one that is more reflective of the emission rate from the stack testing completed for the source's Title V Renewal Application—then the emissions reductions would be greater than what was assumed in the four-factor analysis.

It's possible that the controlled emission rate with LEC for these specific engines could be even lower that 1 g/hp-hr. For reference, the following additional sources of information regarding NOx emission rates specific to Cooper-Bessemer GMV model engines – both uncontrolled and with LEC technology – are provided here:

- EPA's 2000 RICE Update includes NOx emissions test data for specific engines, including Cooper-Bessemer GMV-10C, 2-stroke, lean-burn, 1,100 hp RICE retrofitted with LEC. Tested at 0.61 g/bhp-hr.[469]

- An evaluation by a technical group for the Pipeline Research Council International looked at three of the most representative make / models of 2-stroke lean burn compressor engines: (1) 2,250 hp Cooper GMVH-10; (2) 2,000 hp Clark TLA-6; and (3) 2,500 hp Cooper GMW-10. According to a technical report by the Ozone Transport Commission (OTC) describing this evaluation, "[t]he evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring."[470]

[469] EPA 2000 RICE Update at 4-8.
[470] 2012 OTC Report at p. 24.

LEC controls at unit 5A would be even more cost effective if the baseline emission rate is more in line with the stack test data provided in the source's Title V Renewal Application (i.e., reflective of 88% control).

ETC Texas Pipeline states that units 4A and 5A are backup engines that operate, on average, 25-50% of the time each year.[471] The four-factor analysis is based on operating hours from the 2016 emissions inventory of 560 hours for unit 4A and 4,290 hours for unit 5A, or 6% and 50% operation, respectively. Therefore, the cost effectiveness of LEC controls at unit 4A would be more favorable than what is shown in the four-factor analysis for operation between 25-50%. Revising ETC Texas Pipeline's cost effectiveness analyses to address some of these issues, including assuming 1) 88% control of NOx at unit 5A, and 2) unit 4A operating 50% of the year, results in more favorable cost effectiveness of these controls, as shown in the table below.

Table 31. Cost Effectiveness of LEC at Uncontrolled Jal No. 3 Gas Plant Units 4A and 5A to Reduce NO_x Levels to 1 g/hp-hr, Assuming 89% Control (Unit 4A) and 88% Control (Unit 5A) and Unit 4A Operating 50% of the Year, 2019 $

Unit	Size [hp]	Capital Cost of LEC (vendor quote)	Annual O&M Costs (13% of Capital Costs)	Total Annualized Costs of LEC to Reduce NOx to 1 g/hp-hr (88-89% NOx Reduction)	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC, $/ton
4A	1,100	$798,355	$103,786	$135,720	4,380	45	$3,042/ton
5A	1,100	$798,355	$103,786	$135,720	4,290	37	$3,624/ton

Note, the cost effectiveness of LEC controls would be more favorable for both units if they were able to meet controlled emission rates below 1 g/hp-hr, which, as discussed earlier, has been demonstrated for other LEC retrofits for similar engines.

2. Use of SCR

ETC Texas Pipeline also evaluated SCR as a control for the two-stroke lean burn engines at Jal No. 3. The company did identify concerns with applicability of SCR to the two-stroke lean burn units including reagent injection control, exhaust temperature requirements, variations in the exhaust NO/NO_2 ratio, and engine oil carryover harming the SCR catalyst.[472] In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by

[471] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at 2.
[472] *Id.* at 4.

reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[473]

Irrespective of the company's concerns with applicability of SCR to the lean burn engines, ETC Texas Pipeline did conduct a cost effectiveness evaluation for SCR at Units 4A and 5A assuming a target NOx emission rate of 1 g/hp-hr.[474] Specifically, the company estimated the cost effectiveness of SCR at Unit 4A, which in its base emissions only operated 560 hours per year, as $28,561/ton, and at Unit 5A, which operated 4290 hours in its base emissions, at $7,517/ton.[475]

ETC Texas Pipeline appears to have used a 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines to estimate capital costs for SCR.[476] Specifically, the NESCAUM formula which was based on only one case study for a RICE unit to "approximate" SCR capita costs for lean burn RICE is as follows:

$310,000 + ($72.7 x hp)[477]

This NESCAUM equation is twenty years old and is likely based on cost data from the 1990's. SCR has been implemented on numerous source types over the past twenty years, and the much wider-scale implementation and innovation in catalyst design has lowered the cost of SCR.[478] Yet, ETC Texas Pipeline's analysis escalated the capital costs developed with the above equation from the 2000 NESCAUM report by assuming the NESCAUM cost equation was based on 1994 costs and escalating to 2019, using the differences in the Consumer Price Index between 1994 and 2019.[479] EPA's Control Cost Manual cautions against escalating costs more than five years due to the potential for significant inaccuracies in price estimates.[480]
EPA currently has a spreadsheet available to estimate the capital and operating costs for SCR. While the spreadsheet was developed for fossil fueled fired boilers, it can be used as an estimate for SCR at other natural gas-fired sources and, in fact, has been used oil and gas companies for several four-factor analyses submitted to NMED. Unfortunately, ETC Texas Pipeline did not include the necessary information to use the EPA SCR cost spreadsheet to estimate SCR costs for the Units 4A and 5A engines. NMED should ask the company to use the EPA spreadsheet rather than the NESCAUM formula and escalate the cost 25 years to current dollars.

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[473] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[474] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at 2.
[475] *Id.* at Appendix B.
[476] *Id.* at 8. *See also* December 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines at III-30.
[477] *Id*.
[478] See EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.
[479] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at Appendix B.
[480] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.

In addition, the company's assumed annual operations and maintenance cost, estimated to be 20% of the total capital cost, is arbitrary and unjustified. In particular, ETC Texas Pipeline's annual operations and maintenance costs have no connection to the operating capacity of Units 4A and 5A. As a comparison, in Section XIX.A.2. below, we provide an SCR cost estimate using the EPA cost spreadsheet for the Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[481] For the two units at Roswell Compressor No. 9, that are 4500 hp each and that operate at 11% to 41% of available hours, the operation and maintenance costs to achieve 90% NOx reduction were roughly $26,000/year. See Table 46 in Section XIX.A.2. below.

If we assume that the operation and maintenance expense at Units 4A and 5A are the same as the larger units at Roswell Compressor No. 9 – i.e., $26,000 per year rather than ETC Texas Pipeline's assumed $134,973 per year, the cost effectiveness of SCR at Units 4A and 5A at Jal No. 3 decrease to $10,191/ton at Unit 4 A and $2,459/ton at Unit 5A. Thus, a more appropriate annual operations and maintenance cost make SCR very cost effective particularly at Unit 5A which operates more than Unit 4A.

For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal. NMED should request that ETC Texas Pipeline submit a refined analysis of SCR cost effectiveness using the EPA SCR cost spreadsheet.

B. SO2 Emissions from Thermal Oxidizer

ETC Texas Pipeline also evaluated controls for thermal oxidizer which combust the acid gas stream from its amine units.[482] We address that analysis in Section XXIII of this report.

XII. Davis Gas Processing Denton Gas Plant

The Denton Gas Plant is a natural gas processing plant in which the H2S is removed from the natural gas in an amine unit and then the gas is processed through a cryogenic unit to condense natural gas liquids.[483] The plant is located about 11 miles east of Lovington, New Mexico in Lea County. It is owned/operated by Davis Gas Processing. The plant consists of an amine unit, dehydrator regenerator, four-stroke rich burn RICE units, heaters, and tanks, but SO2 emissions from flaring of acid gases are the primary source of air emissions from the plant.[484] Thus, the four-factor analysis for this facility focused on the amine unit and the acid gas flare (Unit No. 007)Amine unit and flare.[485] Comments on the company's four-factor analysis are provided in Section XXIII further below, in comments on amine units and flaring emissions.

[481] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 5.
[482] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at 7.
[483] 5/10/2017 Title V Operating Permit No. P079-R3 for Davis Gas Processing Denton Gas Plant at 4.
[484] *Id.* at A6 to A8.
[485] November 2019 Four-Factor Analysis for Denton Gas Plant at 2-1.

XIII. El Paso Natural Gas Company – Washington Ranch Storage Facility

The El Paso Natural Gas Company, LLC. (EPNG) Washington Ranch Storage Facility is located in Eddy County and was identified by NMED as one of the sources contributing to regional haze at Carlsbad Caverns National Park Class I area.[486] NMED has described the facility processes as follows:

> The function of the facility is to compress and inject pipeline quality natural gas into underground storage wells and withdraw the gas for delivery into the pipeline.[487]

According to the permit, the plant includes two 2-stroke lean-burn reciprocating internal combustion engines (RICE), a 4-stroke rich-burn auxiliary engine, a glycol dehydrator and reboiler, a heater, a flare, and a diesel water pump engine.[488] In EPNG's four-factor submittal, the company evaluated air pollution controls for the following emission units:

- Cooper-Bessemer 2SLB RICE 12Q155HC2: Units A-01 and B-02.[489]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[490] The following provides a review of the company's four-factor analyses.

A. Units A-01 and B-02: Cooper-Bessemer 12Q155HC2 2-Stroke Lean-Burn Compressor Engines

Units A-01 and B-02 are 2-stroke lean-burn RICE that were constructed in 1982, each with a capacity of 4,500 hp.[491] The units each have an hourly NOx limit of 27.3 lb/hr and an annual NOx limit of 119.5 tpy.[492]

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[486] November 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Washington Ranch Storage Facility at 3.
[487] Title V Operating Permit P064-R3 for Washington Ranch Storage Facility at 3.
[488] *Id.* at 5-6.
[489] November 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Washington Ranch Storage Facility at 4.
[490] *Id.* at 4.
[491] Title V Operating Permit P064-R3 for Washington Ranch Storage Facility at 5.
[492] *Id.* at 6.

1. Use of Low Emission Combustion Technology

EPNG describes a "layered approach" strategy for Clean Burn technology applied to the two engines reviewed in its four-factor analysis, A-01 and B-02.[493] Specifically, EPNG states that these units are already equipped with a turbocharger, advanced ignition system, pre-combustion chambers, high pressure fuel injection systems, and an Automatic Balancing Platform.[494] According to EPNG these Clean Burn technologies, based on manufacturer guidance, result in NOx emission rates of 0.5–2.75 g/hp-hr, or 27–82% reduction in NOx emissions.[495] Based on the information provided on the different Clean Burn technologies available for these engines it's possible that there are additional technologies that could be employed to ensure the NOx emission rates are closer to 0.5 g/hp-hr. For example, it's not clear if the pre-combustion chamber installed on units A-01 and B-02 is a "closed loop ePCC," which corresponds to emission rates of 0.5 g/hp-hr.[496] And it's also not clear if the Automatic Balancing Platform is considered "Advanced TER Control" or "Transient Control," the latter of which would result in emission rates around 0.5 g/hp-hr.[497] In EPA's Alternative Control Techniques document for RICE it reports achievable emission levels for retrofit low-emission designs for a Cooper-Bessemer 16Q155HC engine of 1.8 g/hp-hr.[498] And more recently, EPA has described layered combustion as demonstrated control techniques for 2-stroke lean-burn engines, achieving a NOx emission rate of 0.5 g/hp-hr.[499]

Units A-01 and B-02 have an allowable NOx emission rate of 27.3 lb/hr, or 2.75 g/hp-hr for these 4,500 hp units. And the source's Title V Permit Renewal Application specifies that these permit limits are based on the design for the low emission conversion.[500] NMED should require additional LEC retrofit techniques be evaluated in order to assess the cost effectiveness of further reducing NOx emissions from these engines to a level closer to 0.5 g/hp-hr. Reducing emissions to this level would achieve an additional 82% reduction in NOx emissions from these compressor engines. If these engines operate frequently it could be cost effective to update the Clean Burn technology on these engines, resulting in potentially significant NOx emissions

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[493] November 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Washington Ranch Storage Facility at 8.
[494] *Id.*
[495] *Id.*
[496] *Id.* Note, Hoerbiger's Layered Approach Strategy for Clean Burn Technologies (Figure 3) illustrates varying prechamber (PCC) technologies, including "ePCC" and "closed loop ePCC." Hoerbinger's website describes this technology as Electronic Pre-Chamber Check (ePCC) Valves, *see* https://www.hoerbiger.com/en-3/pages/102

[497] *Id.*
[498] EPA 1993 Alternative Control Techniques Document for RICE at 5-68.
[499] 2016 EPA Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS (Docket ID No. EPA-HQ-OAR-2015-0500), Appendix A at 5-5, *available at:* https://19january2017snapshot.epa.gov/sites/production/files/2015-11/documents/assessment_of_non-egu_nox_emission_controls_and_appendices_a_b.pdf [hereinafter referred to as "CSAPR TSD for Non-EGU NOx Emissions Controls"].
[500] September 2013 Title V Permit Renewal Application El Paso Natural Gas Company, LLC Washington Ranch Storage Facility Section 6, Page 2.

reductions. At continuous operation these units have the potential to emit 120 tons per year of NOx each; an 82% reduction using layered combustion to meet a 0.5 g/hp-hr NOx emission rate would prevent almost 200 tons per year of NOx emissions from both units, when operating continuously.

2. Use of SCR

EPNG did not evaluate SCR for Units A-01 and B-02 primarily because it claimed that it was not technically feasible for variable load engines of this type.[501] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly because EPNG has not found LEC to be a cost effective NOx reduction strategy for these units.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[502]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[503] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[504] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of \$2,400/ton to \$2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

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[501] November 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Washington Ranch Storage Facility at 7.

[502] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.

[503] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.

[504] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

XIV. Enterprise Blanco Compressor C & D

The Blanco C & D Compressor Station is a natural gas compressor station located about one mile northeast of Bloomfield, New Mexico in San Juan County.[505] It is owned/operated by Enterprise Field Services LLC.

The Title V operating permit for the facility indicates that the plant includes several natural gas-fired turbines, flares, and tanks.[506] In Enterprise's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- GE 5221W combustion turbines (Units T-C01 and T-C02)
- GE M5322B combustion turbine (Unit T-D01)[507]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[508] The following provides a review of the company's four-factor analyses. The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

Enterprise used an 8.38% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[509] This is an unreasonably high interest rate for cost effectiveness analyses. EPA's Control Cost Manual indicates that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[510] The current bank prime rate is 3.25%.[511] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[512] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. However, in a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[513] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate

[505] Title V Operating Permit P218-R2M1 for Blanco C&D Compressor Station at 3.
[506] *Id.* at 7.
[507] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at 1-2.
[508] *Id.*
[509] *Id.* at Section 8.0 Supporting Documentation.
[510] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[511] https://www.federalreserve.gov/releases/h15/.
[512] https://fred.stlouisfed.org/series/DPRIME.
[513] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

(and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. Enterprise's use of an 8.38% interest rate is unreasonably high and overstates the cost effectiveness of pollution controls evaluated in the four-factor analyses.

B. GE Combustion Turbines: Units T-C01 and T-C02 and T-D01

Units T-C01 and T-C02 at the Blanco C&D Compressor Station are each 22,280 hp natural gas-fired turbines that are listed in the Title V permit as constructed before June 1989.[514] The units each have a NOx emissions limit of 80.0 lb/hr and 350.4 tpy.[515] For these units, Enterprise identified water or steam injection as viable combustion controls for NOx but claimed that dry low NOx combustors were not available for retrofit to these types of gas turbines.[516] Unit T-D01 is a GE M5322B combustion turbine of 32,550 hp capacity that is identified in the Title V permit as being constructed before October 1987.[517] Unit T-D01 has NOx limits of 143.3 lb/hr and 628 tpy.[518] For this unit, Enterprise identified water or steam injection or dry low NOx combustors as feasible controls.[519] Enterprise claimed that SCR installation was not possible for any of these gas turbines, due to the size estimates of the SCR.[520] Presumably, Enterprise is claiming issues of retrofit difficulty. There is no question that SCR is technically feasible for natural gas-fired combustion turbines, including those used at compressor stations.

1. Evaluation of Baseline NOx Emissions.

According to the company's cost analysis for water/steam injection, Unit T-C01 has an actual NOx emission rate of 36.92 lb/hr (57.7 ppm), Unit T-C02 has an actual NOx emission rate of 51.56 lb/hr (83.2 ppm), and Unit T-D01 has an actual NOx emission rate of 49.32 lb/hr (65.0 ppm) based on 2016 stack test data.[521] These actual emission rates are much lower than the units' allowable NOx emission rates so, either the 2016 stack test data was not performed while the engines were operating at maximum capacity or the allowable NOx emission rates have been set unreasonably high. In addition, while both Units T-C01 and T-C02 are the same model and same horsepower, one unit's NOx rate (T-C01) is listed by Enterprise as 31% lower than the NOx rate of T-C02. That does not make sense, if such emission rates are reflective of test data at maximum or close to maximum capacity. NMED should present information on the 2016 stack test data so the circumstances of the stack tests can be reviewed. In addition, NMED and Enterprise should review other stack tests for these units to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. If testing is only done sporadically, such as once every five years, then it is

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[514] Title V Operating Permit P218-R2M1 for Blanco C&D Compressor Station at 7.
[515] *Id.* at 8.
[516] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at 2-2 to 2-4.
[517] Title V Operating Permit P218-R2M1 for Blanco C&D Compressor Station at 7.
[518] *Id.* at 8.
[519] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at 2-2 to 2-4.
[520] *Id.* at 2-4.
[521] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at Section 8.0.

questionable that such stack test data truly reflect an accurate projection of emissions expected over the lifetime of the controls being evaluated, especially given that the emission rates are so much lower than the units' allowable pound per hour emission rates. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on an estimate of emissions expected in 2028.

2. Evaluation of Water Injection and Steam Injection for NOx Control

Enterprise only assumed 15% NOx reduction from water or steam injection.[522] While Enterprise cites to EPA's AP-42 emission factor documentation for the 15% control with water or steam injection, EPA's AP-42 states that such controls can achieve 60% or higher NOx removal.[523] EPA's 1993 Alternative Control Techniques Document for NOx emissions from Stationary Gas Turbines, which EPA's AP-42 documentation cites to, states that NOx rates in the range of 25 to 42 ppmv can be achieved with water or steam injection as gas-fired combustion turbines.[524] If the uncontrolled emissions of Units T-C01, T-C02, and T-D01 are truly in the range of 57.7 to 83.2 ppm as indicated in Enterprise's four-Factor analyses (assuming this is parts per million by volume at 15% oxygen, which NMED should confirm), water injection to meet a NOx rate of 25-42 ppm reflects 27% to 70% NOx removal. NMED must require that Enterprise evaluate water or steam injection for these units reflective of the NOx rates that have historically been achieved with water or steam injection.

With respect to the life assumed of water or steam injection, Enterprise only assumed a 15-year life of these controls.[525] Enterprise did not provide any justification for assuming such a short life of water or steam injection. As discussed in NPCA's March 2020 report, the life of water or steam injection should be the life of the combustion turbines. In NPCA's March 2020 report, we assumed a 25-year life of water or steam injection.[526]

In terms of Enterprise's costs for water injection or steam injection, the company's capital costs seem very high for the size turbines, based on a comparison to the 1999 Department of Energy report entitled "Cost Analyses of NOx Control Alternatives for Stationary Gas Turbines," which is cited in several EPA and State documents on the costs of NOx controls at gas turbines.[527] In that 1999 DOE report, the costs of water or steam injection for a gas turbine that is larger than Units T-C01 and T-C02 and slightly smaller than T-D01, a GE LM2500 turbine which is of 22.7 megawatt capacity or about 30,400 hp, the capital cost in 1999 dollars of water injection was

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[522] *Id.*

[523] EPA, AP-42 Emission Factor Documentation, at 3.1-6.

[524] *See* EPA. Alternative Control Techniques Document – NOx Emissions form Stationary Gas Turbines, EPA-453/R-93-007, January 1993, at 2-5 [hereinafter EPA 1993 Gas Turbine ACT].

[525] November 2019 Regional Haze Four-Factor Analysis for Blanco C&D Compressor Station at 6-1.

[526] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 64.

[527] Bill Major, ONSITE SYCOM Energy Corporation, and Bill Powers, Powers Engineering, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, prepared for U.S. Department of Energy, November 5, 1999, available at: https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf [hereinafter "1999 DOE Report"].

estimated to be $1,083,175.[528] Although EPA's Control Cost Manual advises against escalating costs more than five years because it can lead to inaccuracies in price estimation,[529] just using the Chemical Engineering Plant Cost Indices between 1999 and 2018, the DOE's 1999 costs of water injection for a larger GE LM2500 gas turbine would increase to $1.67 million.[530] Using a different cost index specific to oil refineries, the Nelson-Farrar index, the 1999 costs of water injection increase from $1.0 million to $1.88 million as of 2016 (the most recent annual Nelson-Farrer cost index found online).[531] Yet, Enterprise's capital cost estimate for water injection at T-C01 and T-C02 was $6.1 million, more than three times the escalated capital costs from the 1999 DOE report based on either the CEPCI index or the Nelson-Farrar index. Thus, Enterprise's capital cost estimate of water injection for a smaller capacity gas turbine at these units seem very high, and its capital costs for steam injection are $2 million higher than its costs for water injection. Further, the inspection and operating costs of water injection, which Enterprise stated would be $1,238,327 per year,[532] are not explained or documented and seem unreasonably high. NMED must request more details and support for these cost estimates of water injection and of steam injection at these units.

We addressed just some of these issues to revise Enterprise's cost effectiveness analyses to reflect 1) a 4.7% interest rate (instead of 8.38%), 2) a 25-year life of water or steam injection (instead of an assumed 15-year life), 3) a controlled NOx rate with water or steam injection of 25 ppmvd at 15% O_2. With the revisions listed in items 1 through 3 above, Enterprise's cost effectiveness of water or steam injection reduced from approximately $57,000 to $110,000/ton of NOx removed to $14,000 to $51,000/ton, and it is important to note that no changes were made to Enterprise's apparently inflated capital and operating costs of water or steam injection.

In its identification of energy and non-air quality environmental impacts of compliance, Enterprise did not list water use as an adverse environmental impact, but it is an issue to be concerned with for water injection.[533] That is why dry low NOx combustion, if available (which Enterprise claims is not available for the Units T-C01 and T-C02 turbine models) or selective catalytic reduction (SCR) are more preferable choices for NOx control from gas-fired turbines in New Mexico.

3. Evaluation of Dry Low NOx Combustion at Unit T-D01

Enterprise did evaluate dry low NOx combustors for the GE M5322B unit (Unit T-D01), but claimed that dry low NOx combustors could only achieve a NOx rate of 35 ppmv at this unit, or

[528] *Id.*, Appendix A at A-4.
[529] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.
[530] Based on multiplying the 1999 cost estimate for water injection from the 1999 DOE report by the ratio of the CEPCI indices for 2018 to 1999 (603.1/390.6).
[531] Based on multiplying the 1999 cost estimate for water injection from the 1999 DOE report by the ratio of Nelson-Farrar indices for 2016 to 1999 (2598.7/1497.2).
[532] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 8-2 to 8-3.
[533] *See* March 6, 2020 NPCA Oil and Gas Four-Factor Report at 67-68.

a NOx reduction efficiency of 46%. This is a high NOx rate and a low NOx removal efficiency to assume with dry low NOx combustors. As discussed in NPCA's March 2020 Oil and Gas Four-Factor Report, such controls can achieve NOx removal efficiencies of 80-95% with typical NOx emission rates in the range of 9-15 ppm.[534] In a 1999 Department of Energy Report on the costs of NOx controls for gas combustion turbines, the highest NOx emission rate evaluated with dry low NOx combustors was 25 ppm.[535] Thus, Enterprise's cost effectiveness analysis for dry low NOx combustors assumed an unreasonable low level of NOx reduction with this control.

In terms of the life of dry low NOx combustion controls in the cost effectiveness analyses, Enterprise's analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[536]

In the table below, Enterprise's cost effectiveness analyses of dry low NOx combustors were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate. In addition, two lower NOx rates were evaluated: 25 ppm and 15 ppm.

Table 32. Revised Cost Effectiveness of Dry Low NOx Combustors at Unit T-D01 of the Blanco C&D Compressor Station, to Reflect a 4.7% Interest Rate and a 25 Year Life[537]

NOx Emission Rate Evaluated, ppm	NOx Removal Efficiency Evaluated	Annual Cost of Dry Low NOx Combustors (at 4.7% interest and 25 Year Life)	NOx Emissions Reduced, tpy	Cost Effectiveness
35[538]	46%	$609,798	91.04	$6,694/ton
25	62%	$609,798	121.46	$5,021/ton
15	77%	$609,798	151.82	$4,017/ton

Dry low NOx combustors at Unit T-D01 are much more cost effective than water or steam injection and, based on historical assumed NOx emission rates with these controls which range between 15 to 25 ppm (or even as low as 9 ppm), such controls should be able to reduce NOx emissions at Unit T-D01 by 62 to 77% or maybe more.

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534 March 2020 NPCA Oil and Gas Four-Factor Report at 69.

535 *Id. See also* Bill Major, ONSITE SYCOM Energy Corporation, and Bill Powers, Powers Engineering, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, prepared for U.S. Department of Energy, November 5, 1999, 2-10, available at: https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf.

536 *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

537 The company's capital and operational and maintenance costs were not revised for this analysis. Only the interest rate was reduced from 8.38% to 4.7% and the life of controls was revised from 20 to 25 years.

538 This in the NOx rate evaluated by Enterprise for dry low NOx combustors at Unit T-D01.

4. Evaluation of SCR for the Gas Turbines at Blanco C&D Compressor Station

Enterprise did not evaluate SCR for the gas turbines at the Blanco C&D Compressor Station, stating that it was "not possible to install these units at the Blanco facility" due to "the amount of buffer space needed to maintain accessibility to equipment and to avoid compromising worker safety."[539] While the facility and gas turbines may not have been originally designed to have space to accommodate SCR, that is typically the case with most SCR retrofits. As such, there have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints. For example, for many large coal-fired power plants, SCR reactors have been elevated above the air preheaters. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new foundations to make way for the SCR reactor.[540] Thus, before NMED accepts a very brief claim of retrofit difficulty of SCR at any emissions unit being evaluated for reasonable progress controls, it is imperative that NMED ask Enterprise for a site plan and photos that shows whatever space constraints are being claimed. Moreover, NMED must ask Enterprise to consult with SCR vendors for options for SCR installation at the gas turbines of the Blanco C&D Compressor Station.

If any of the combustion turbines are in close proximity to another turbine, that provides opportunities for a shared SCR reactor which could help with retrofit space issues as well as with costs. NMED must require all possibilities for SCR installation be evaluated and documented by Enterprise. The state must not simply discount this highly effective NOx control based on a claim of some retrofit difficulty.

In terms of the costs of SCR control, NPCA's March 2020 Oil and Gas Four-Factor Report showed the cost effectiveness in 1999 dollars for SCR achieving about 90% NOx reductions would range from $2000/ton to $3400/ton for a 5 MW combustion turbine (~6800 hp engine) depending on the operating capacity factor, and costs decrease for larger turbines like Units 17 and 19 which are approximately 19500 hp engines.[541] For much larger combustion turbines of 75 MW generating capacity (~100,500 hp), cost effectiveness of SCR was significantly lower in the range of $560-$850/ton depending on operating capacity factor.[542]

To get an idea of the costs for SCR at Units T-C01, T-C02, and T-D01 in current dollars, one can use EPA's SCR cost spreadsheet made available as part of EPA's Control Cost Manual. It is difficult to estimate an actual cost effectiveness because it is not clear what the 2016 actual annual fuel throughput was at each unit, which is necessary for estimating annual operations and maintenance costs for SCR. However, a 2017 Title V Permit Application for Blanco C & D

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[539] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at 2-4.
[540] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, , available at https://www.onepetro.org/conference-paper/SPE-66501-MS.
[541] *See* NPCA March 2020 Oil and Gas Four-Factor Report at 75.
[542] *Id.*

compressor stations does have information to enable an estimate of the capital cost of SCR. A review of the EPA SCR cost spreadsheet shows that the capital cost of SCR is based primarily on two factors: maximum hourly heat input to the unit in MMBtu/hr and the site elevation.[543] A 2017 Title V Permit Application for Blanco C&D compressor stations has the maximum hourly heat input to each unit as well as other data, although some of the other data is not legible in the copy of the document on NMED's Emissions Analysis Tool website.[544] Specifically, the hourly heat input to Units T-C01 and T-C02 is identified as 283 MMBtu/hr and the hourly heat input to Unit T-D01 appears to be 311.18 MMBtu/hr.[545]
The site elevation is listed as 5605 feet.[546]

Enterprise's claimed baseline NOx emission rates of 57.2 ppm, 87.3ppm, and 65.0 ppm for Units T-C01, T-C02, and T-C03 were utilized and assumed to be reflective of ppm by dry volume at 15% oxygen. As previously discussed, NMED should ensure that this 2016 test data reflects operations at maximum operating capacity and ensure that these emission rates are a reasonable projection of NOx emissions as of 2028. The company's actual NOx rates were converted to lb/MMBtu emission rates using a conversion formula from EPA's 1993 Alternative Control Techniques Document for Stationary Gas Turbines.[547] Enterprise's ppm NOx baseline rates thus were converted to 0.231 lb/MMBtu for Unit T-C01, 0.334 lb/MMBtu for Unit T-C02, and 0.341 lb/MMBtu for Unit T-D01. With this data, unit-specific information was input into EPA's SCR cost spreadsheet to estimate cost effectiveness of SCR at these units. For Units T-C01 and T-C01, the average exhaust gas temperature of the bypass stacks of 625 degrees Fahrenheit was used and for Unit T-D01 the exhaust gas temperature of 904 degrees Fahrenheit was used.[548] Two different SCR control levels were assumed: a 15 ppmvd NOx rate, which reflects 74% to 82% NOx removal at the Blanco C&D combustion turbines, and a 90% control efficiency from current uncontrolled actual NOx rates at each turbine. With Enterprise's 2016 actual annual NOx emissions and its reported ppm NOx emissions and the reported heat value of the fuel, actual annual gas consumption rates were estimated for each unit for input into the SCR cost spreadsheet. Capital costs were annualized applying a cost recovery factor using a 4.7% interest rate, and a 25-year life which EPA has identified as typical for SCR systems used at industrial boilers.[549] One reagent type was evaluated: 29% aqueous ammonia. The results of these analyses are provided in the table below.

[543] *See* equations in "Cost Estimate" tab, cell B19 (Total Capital Investment), which in turn points to cells G19 and H19, which in turn are based on "Data Inputs" tab cells C10 and C24.
[544] June 27, 2017 Application for Significant Modification, Title V Operating Permit P218-R2, Enterprise Field Services LLC – Blanco C&D Compressor Station, at pdf pages 34-35.
[545] *Id.*
[546] *Id.* at 35. Note the site elevation for Units T C-01 and T-C01 is not legible, but it is assumed that each C and D compressor station are at the same elevation.
[547] *See* EPA, Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993, Appendix A which has conversion equations for natural gas-fired combustion turbines.
[548] *Id.* at pdf page 34-35.
[549] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

Table 33. Cost Effectiveness of SCR at Blanco C&D Compressor Stations Units T-C01, T-C02, and T-D01 Combustion Turbines, Using EPA's SCR Cost Calculation Spreadsheet for Boilers (2018 $)

Unit	Assumed NOx Removal Efficiency with SCR	Capital Cost SCR	Annual Operational and Maintenance Cost	Total Annualized Costs	NOx Reduced, tpy	Cost Effectiveness
T-C01	74.0%	$7,536,749	$155,039	$676,647	119	$5,693
T-C01	90.0%	$7,536,749	$161,977	$683,585	144	$4,731
T-C02	82.0%	$7,536,749	$160,398	$682,006	180	$3,787
T-C02	90.0%	$7,536,749	$164,425	$686,034	198	$3,472
T-D01	77.0%	$8,016,420	$159,735	$714,374	153	$4,684
T-D01	90.0%	$8,016,420	$166,270	$720,909	178	$4,044

The cost estimates of SCR based on EPA's boiler SCR cost spreadsheet project costs for SCR that are significantly lower than the other NOx control evaluated by Enterprise – water or steam injection or dry low NOx combustion for Unit T-D01, for which capital costs were projected to range from $6.6 to $8.2 million.[550] Given that SCR can achieve much higher levels of control at much lower costs than water or steam injection, NMED must require Enterprise to more fully evaluate the ability to install SCR at Unit 17 and/or 18 . Ninety percent control should be readily achievable with SCR at these units to meet a NOx emission rate of 5 to 8 ppmv (0.0231 to 0.0334 lb/MMBtu). Before allowing Enterprise to dismiss SCR due to claims that it is not feasible to locate one or more SCR reactors at Units T-C01, T-C02, and T-D01, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at the units, including any options for shared SCR reactors between Units T-C01 and T-C02. SCR can be a very effective method for reducing NOx emissions from the Blanco C & D compressor station gas turbines and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for the Blanco C & D Compressor Station.

XV. Harvest Pipeline – San Juan Gas Plant

The Harvest Pipeline Company San Juan Basin Gas Plant is a facility that extracts and processes natural gas liquids and residue gas products from field gas via a cryogenic process. It is located about 2 miles northeast of Bloomfield, New Mexico. The facility consists of several combustion turbines, a diesel generator, heaters, a thermal oxidizer, and a flare.[551] It is located adjacent to the Blanco Compressor Stations of EPNG (Blanco C&D) and El Paso Field Services (Blanco A).[552]

[550] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at 8-1 to 8-3.
[551] *Id.* at A6.
[552] Title V Permit No. P124-R3 for San Juan Basin Gas Plant, at A3.

In fact, the three Blanco Compressor Stations and the San Juan Gas Plant are all considered one source under the New Source Review program by NMED.[553]

In Harvest Pipeline's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Rolls Royce 155 Natural Gas Turbines (Units 1-4)
- Solar Centaur T4501 Natural Gas Turbines (Units 4-7).[554]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[555] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

Harvest Pipeline used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[556] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[557] The current bank prime rate is 3.25%.[558] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[559] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[560] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

[553] 10/10/2018 Statement of Basis for San Juan Gas Plant, Permit Nos. 0613-M8 and P124-R3 at 2.
[554] November 2019 Regional Haze Four-Factor Analysis for Harvest San Juan Gas Plant at 1-2.
[555] *Id.*
[556] *Id.* at Appendix B Cost Analysis Calculations.
[557] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[558] https://www.federalreserve.gov/releases/h15/.
[559] https://fred.stlouisfed.org/series/DPRIME.
[560] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

B. Rolls-Royce 155 Combustion Turbines: Units 1-4 at San Juan Gas Plant

Units 1-3 of the San Juan Gas Plant are Rolls-Royce Natural Gas Turbines that were manufactured in the mid-1980's.[561] The turbines have a permitted capacity of 15000 hp each, although they have a manufacture rated capacity of 23,800 hp.[562] Unit 4 is a rotating spare for Units 1 – 3, which operates only when Units 1, 2, or 3 are down for repair.[563] The turbines have catalytic oxidation for carbon monoxide and volatile organic compound (VOC) control.[564] The units are each subject to a NOx limit of 56.3 lb/hr and 246.4 tpy.[565] The units are also subject to a NOx limit of 150 ppmv at 15% O_2 pursuant to 40 C.F.R. Part 60, Subpart GG.[566]

For these units, Harvest Pipeline did not evaluate any additional NOx pollution controls. The company stated that it contacted Siemens, the company that currently owns the Rolls-Royce Avon gas turbine and compressor business, and that Siemens stated that neither dry low NOx combustion nor water or steam injection was an available control option for retrofit to the mid-1980's era Rolls-Royce turbines at the San Juan Gas Plant.[567] Siemens indicated that SCR is available for the turbine model, yet Harvest Pipeline did not evaluate SCR. The following provides comments on SCR applicability for the Rolls-Royce turbines.

1. Evaluation of SCR at the Rolls-Royce Turbines (Units 1-4)

Although, according to the four-factor analysis for the San Juan Gas Plant, Siemens claimed that SCR was an available technology for the Rolls-Royce turbines, Harvest Pipeline did not evaluate SCR technology for the turbines. The company claimed that the high exhaust temperature of the turbines (1250 degrees Fahrenheit according to the four-factor analysis) and concerns about space and power usage made SCR not feasible for the Rolls-Royce turbines.[568] SCR should not have been so readily discounted as a pollution control for the Rolls-Royce turbines. With respect to space limitations, as discussed in Section I.B.3. above, most SCR retrofits have space limitations, because the facility was not likely designed to have space to accommodate SCR. There have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints. For example, for many large coal-fired power plants, SCR reactors have been elevated above the air preheaters. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new

[561] Title V Permit No. P124-R3 for San Juan Basin Gas Plant, at A6.
[562] *Id.*
[563] November 2019 Regional Haze Four-Factor Analysis for Harvest San Juan Gas Plant at 1-3.
[564] *Id.* at A7.
[565] *Id.*
[566] *Id.* at A8.
[567] *Id.* at 2-3 to 2-4.
[568] *Id.* at 2-5 to 2-6.

foundations to make way for the SCR reactor.[569] Thus, before NMED accepts a very brief claim of retrofit difficulty of SCR at any emissions unit being evaluated for reasonable progress controls, it is imperative that NMED ask Harvest Pipeline for a site plan and photos that shows whatever space constraints are being claimed, and that NMED ask the company to consult with SCR vendors for options for SCR installation at the gas turbines.

Depending on the proximity of the gas turbines, it is possible that one SCR reactor could be used by more than one combustion turbine. This would reduce costs and potentially be easier to install at the site. NMED should require all possibilities for SCR installation be evaluated and documented by Enterprise. The state must not simply discount this highly effective NOx control based on a claim of some retrofit difficulty.

Regarding the company's stated exhaust temperature of 1,271 degrees Fahrenheit, NMED should determine if this is the sustained temperature of the gas turbines or the maximum temperature of the exhaust expected from the turbines. It must be noted that this exhaust temperature of 1,271 degrees Fahrenheit claimed in the four-factor analysis is much higher than the exhaust temperatures of the units cited in the February 2017 Title V permit application for the San Juan Gas Plant. Specifically, the 2017 permit application listed the exhaust temperature of Units 2 and 3 of 370 degrees Fahrenheit and the Unit 1, Unit 2 bypass, and Unit 3 bypass exhaust temperature as 750 degrees Fahrenheit.[570] Thus, NMED must ensure the accuracy of any stated claims about SCR being infeasible due to exhaust gas temperatures before allowing SCR to be eliminated as a control option. In addition, there are options for dealing with high exhaust temperature of simple cycle turbines to enable the use of SCR. The Buckingham Compressor Station which is proposed to be constructed in Virginia would be equipped with Solar turbines with SoLoNOx, SCR, and cooling air skids.[571] Essentially, the cooling air skids provide for the injection of tempering air at the turbine discharge (upstream of the SCR) to cool the exhaust temperature to the optimal temperature of the SCR catalyst.[572]

Further, if the Rolls-Royce turbines truly have exhaust temperatures of 1,271 degrees Fahrenheit, that is another reason why NMED should investigate routing more than one combustion turbine exhaust to a common SCR. The routing of turbine exhausts from multiple turbines to one SCR reactor will allow for some cooling of the exhaust before it enters the SCR. As previously discussed, SRP is planning to route the flue gas from one boiler at the Coronado

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[569] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, , available at https://www.onepetro.org/conference-paper/SPE-66501-MS.

[570] February 2017, New Mexico Application to Renew Permit P-124-R2, San Juan Gas Plant, Submitted by Conoco Phillips Company, at pdf page 39 (San Juan Basin Gas Plant, Turbine Exhaust Emissions Calculations).

[571] *See* May 25, 2018 Permit Application for Altlantic Coast Pipeline LLC, Buckingham Compressor Station, at pdf page 129 (Design Summary), which is available for download at https://www.deq.virginia.gov/Programs/Air/BuckinghamCompressorStationAirPermit/BuckinghamCompressorStationArchivedDocuments.aspx.

[572] *See,* e.g., Buzanowski, Mark A. and Sean P. McMenamin, Peerless Mfg. Co., Automated Exhaust Temperature Control for Simple Cycle Power Plants, available at https://www.powermag.com/automated-exhaust-temperature-control-for-simple-cycle-power-plants/. *See also* Mitsubishi Hitachi Power Systems (MHPS) webpage on SCR systems for simple cycle turbines at https://amer.mhps.com/scr-for-simple-cycle-gas-turbines.html.

Generating Station in Arizona to an existing SCR reactor that had previously been constructed at the coal-fired power plant Coronado Unit 2. Such an approach seems like it could be a viable, more cost effective, control option for co-located combustion turbines at compressor stations.

To estimate the cost effectiveness of SCR for the Rolls-Royce combustion turbines, EPA's SCR cost spreadsheet was used along with the turbine operational data presented in the company's February 2017 Title V Permit Application.[573] Because Harvest Pipeline did not evaluate any emissions controls for the Rolls-Royce units, there was no information in the four-factor analysis on actual emissions and/or actual operating hours for the units. Thus, this SCR cost effectiveness analysis had to be based on an allowable emissions baseline. The uncontrolled NOx rate for input into the spreadsheet was estimated by dividing the allowable hourly emission rate of 56.30 by the hourly fuel consumption of the turbines of 123.2 MMBtu/hr,[574] for an uncontrolled NOx rate of 0.457 lb/MMBtu. Consistent with other SCR analyses presented herein and in NPCA's March 2020 Oil and Gas Four-Factor Report, it was assumed that SCR could achieve a NOx emission rate of 15 ppmv at 15% O_2,[575] which converts to 0.06 lb/MMBtu. That NOx rate reflects an 87% reduction across the SCR system from the lb/MMBtu allowable NOx emission rate. To reflect a lower capacity factor than potential to emit, an analysis was also done assuming the unit operated at 70% of maximum annual fuel throughput. Consistent with all other SCR cost analyses provided herein, a 25-year life of SCR and a 4.7% interest rate was used. The results of this cost effectiveness analysis are provided in the table below.

Table 34. Cost Effectiveness of SCR to Achieve ~87% NOx Reduction (15 ppmv at 15% O_2) at Unit 1, 2, and 3 of the San Juan Gas Plant, Assuming a 25-Year Life of SCR and a 4.7% Interest Rate

Annual Capacity Factor	Capital Cost of SCR	Annual Operational and Maintenance Costs of SCR	Annualized Cost of SCR	NOx Emission Reductions, tpy	Cost Effectiveness of SCR
100%	$4,388,725	$98,826	$403,662	214	$1,884/ton
70%	$4,388,725	$79,310	$387,146	150	$2,562/ton

Harvest Pipeline also indicated that the electricity currently available at the San Juan facility is sufficient to power SCR systems at the Rolls-Royce units, and stated that "[i]nstallation of [SCR] will require the facility to expand its current power generation."[576] Based on electricity calculations of EPA's SCR cost spreadsheet, if SCR systems were operated for each unit and each unit was operated at 100% of maximum capacity, the electricity needs would be 71.91 kW per hour per unit for an hourly demand need of 0.216 MW. NMED should ask Harvest Pipeline

573 February 2017, New Mexico Application to Renew Permit P-124-R2, San Juan Gas Plant, Submitted by Conoco Phillips Company, at pdf page 39 (San Juan Basin Gas Plant, Turbine Exhaust Emissions Calculations).
574 *Id.*
575 *See* March 2020 NPCA Oil and Gas Four-Factor Report at 75.
576 November 2019 Regional Haze Four-Factor Analysis for Harvest San Juan Gas Plant at 2-6.

for more information on its current levels of power generation and/or power supply and to estimate what would be necessary to increase the power generation at the site or to the site to accommodate SCR systems. If one SCR reactor could be shared between the three combustion turbines, that could not only reduce the cost of SCR and allow for a less complicated retrofit, but it could also reduce the energy needs of SCR.

Thus, NMED must not allow Harvest Pipeline to discount SCR for the Rolls-Royce units. It is a highly effective NOx control that the turbine manufacturer (Siemens) states is an available retrofit for the existing turbines. NMED must require a thorough evaluation of SCR to reduce NOx emissions from the Rolls-Royce turbines.

C. Solar Centaur T4501 Natural Gas Turbines (Units 4-7)

Units 4-7 of the San Juan Gas Plant are Solar Centaur turbines model T4501 with a permitted capacity of 3735 hp that were each manufactured in 1986.[577] The units each have NOx limits of 15.9 lb/hr and 69.8 tpy.[578] The units are also each subject to a NOx limit of 150 ppmv at 15% O_2 pursuant to 40 C.F.R. Part 60, Subpart GG.

Harvest Pipeline evaluated the following pollution controls for these units:

- SoLoNOx Combustion Technology
- SCR.

The following provides comments on Harvest Pipeline's analyses of these controls.

1. Evaluation of SoLoNOx for Units 4-7 at San Juan Gas Plant

Harvest Pipeline states that SoLoNOx is available for the existing Solar Centaur combustion turbines at Units 4-7, but it would require the units to be uprated to model Centaur T4701 to support the SoLoNOx technology.[579] Harvest Pipeline states that such controls could reduce NOx to 25 ppm, a reduction of 65-75% from 2016 hourly NOx rates.[580]
In terms of the life of SoLoNOx controls in the cost effectiveness analyses, Harvest Pipeline's analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[581] In the table below, Harvest Pipeline's cost effectiveness analyses of SoLoNOx were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate.

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[577] Title V Permit No. P124-R3 for San Juan Basin Gas Plant, at A6.
[578] *Id.* at A7.
[579] November 2019 Regional Haze Four-Factor Analysis for Harvest San Juan Gas Plant at 2-3.
[580] *Id.*
[581] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

Table 35. Revised Cost Effectiveness of SoLoNOx at Units 4-7 of the Harvest Pipeline San Juan Gas Plant, to Reflect a 4.7% Interest Rate and a 25-Year Life

Unit	Harvest Pipeline's Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	Harvest Pipeline's Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25 Year Life
4	$69,637	$1,952/ton	$61,274	$1,717/ton
5	$69,637	$2,412/ton	$61,274	$2,122/ton
6	$69,637	$1,894/ton	$61,274	$1,667/ton
7	$69,637	$1,500/ton	$61,274	$1,319/ton

Thus, the cost effectiveness of SoLoNOx at the Units 4-7 Solar Centaur Combustion Turbines should be in the range of $1,319/ton to $2,122/ton assuming a more appropriate 25-year life at lower interest rate. These controls should be considered quite cost effective by NMED.

2. Evaluation of SCR for Units 4-7 of the San Juan Gas Plant.

Harvest Pipeline evaluated SCR as a technically feasible control option for the Units 4-7 Solar Centaur gas combustion turbines, using EPA's SCR cost spreadsheet made available with EPA's Control Cost Manual.[582] However, Harvest Pipeline only assumed a 25 ppm NOx rate could be met with SCR, which only reflects 65% to 76% NOx reduction efficiency with SCRAs presented NPCA's Oil and Gas Four-Factor Report, NESCAUM assumed 90% control with SCR in its 2000 Status Report to control small gas turbines down to 15 ppmv.[583] SCR at the San Juan Gas Plant Units 4-7 should be able to at least achieve a 15 ppmv NOx limit, which reflects 79% to 85% control at each unit.

Harvest Pipeline presented cost effectiveness data for SCR at Units 4-7, but the costs appear to be significantly inflated. The company assumed a $4,000,000 capital cost of SCR that it purportedly obtained from the manufacturer, which is Solar Turbines.[584] It is not clear that Solar Turbines is a vendor for SCR systems. The company also apparently used the EPA cost spreadsheet for the direct annual costs including operating and maintenance costs.[585] Yet, when the inputs used by Harvest Pipeline for each unit are independently input in the EPA SCR cost spreadsheet, the annual operation and maintenance costs are shown to be much lower than assumed by Harvest Pipeline, and the capital cost of SCR is shown to be much lower than $4,000,000 per unit. For example, when one enters into the EPA spreadsheet the same

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[582] November 2019 Regional Haze Four-Factor Analysis for San Juan Gas Plant, Appendix C.

[583] NPCA March 2020 Oil and Gas Four-Factor Report at 74-75. *See also* NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15), available at http://www.nescaum.org/documents/nox-2000.pdf/view.

[584] November 2019 Regional Haze Four-Factor Analysis for San Juan Gas Plant at 3-2.

[585] *Id.*

information in the data input page for Unit 4 provided in the San Juan Gas Plant Four-Factor Report, the resulting calculation of operations and maintenance costs are $10,703 per year plus $2,718 in administrative charges for a total of $13,421 per year, whereas Harvest Pipeline assumed annual operating and mainatenance costs of $122,869 per year, costs that are nine times higher than calculated with EPA's cost spreadsheet. In addition, the EPA SCR cost spreadsheet calculates the capital cost of SCR at $1.5 million for the unit rather than Harvest Pipeline's claimed $4 million cost, a value that is 2.7 times what the EPA SCR cost spreadsheet calculated.

In the table below, we recalculated cost effectiveness of SCR at Units 4-7 of the San Juan Gas Plant. For this analysis, we used EPA's SCR cost spreadsheet with the same inputs as identified in Harvest Pipeline's Four Factor report.[586] However, for the controlled level of NOx, an emission rate of 15 ppmv was assumed to be met (reflective of 0.10 lb/MMBtu and NOx removal efficiencies in the range of 79% to 85%. For the reasons previously described in this report, an interest rate of 4.7% and a 25-year life of SCR were assumed. The table below presents the results of this analysis.

Table 36. Cost Effectiveness of SCR at San Juan Gas Plant Units 4, 5, 6 and 7 Combustion Turbines to Meet 15 ppmv NOx Rate, Using EPA's SCR Cost Calculation Spreadsheet for Boilers (2018 $)

Unit	Assumed NOx Removal Efficiency with SCR	Capital Cost SCR	Annual Operational and Maintenance Cost	Total Annualized Costs	NOx Reduced, tpy	Cost Effectiveness
4	82%	$1,501,589	$20,793	$126,820	41	$3,059/ton
5	79%	$1,495,807	$21,342	$126,972	44	$2,869/ton
6	82%	$1,465,046	$21,012	$124,523	44	$2,839/ton
7	85%	$1,475,477	$22,001	$126,230	52	$2,405/ton

The above table shows that SCR, based on EPA's cost algorithms, can be cost effective at Units 4, 5, 6 and of the San Juan Gas Plant.
Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[587] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for

[586] *Id.* in Appendix B, pdf pages 27, 31, 35, and 39 of the report.
[587] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.

such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[588] NMED should require Harvest Pipeline to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

XVI. Oxy USA WTP -Indian Basin Gas Plant

The Oxy USA WTP (Oxy) Indian Basin Gas Plant is a gas sweetening plan (removing hydrogen sulfide and CO_2 from raw natural gas to make commercial natural gas) and also extracts natural gas products (propane and butane) from natural gas.[589] The facility is located 15 miles west of Carlsbad, New Mexico in Eddy County.[590] The emission units at the plant include an amine unit, heaters, turbine generators and turbine compressors, boilers, and flares.[591]

In Oxy's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Natural Gas Simple Cycle Solar Centaur 40-4002 Turbines (Units ES-06/07 & ES-08/09)
- Natural Gas Simple Cycle Solar Centaur 40-4702 Turbine (Unit ES-10/11)
- Amine Gas Treating Units.[592]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[593] The following provides a review of the company's four-factor analyses. Comments on the four-factor analysis for the amine gas treating units are provided further below in Section XXIII.

A. Interest Rate Used in Cost Analyses.

Oxy used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[594] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest

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[588] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.
[589] Title V Operating Permit No. P103-R3, OXY USA WTP Limited Partnership Indian Basin Gas Plant, 11/1/2019, at A3.
[590] *Id.*
[591] *Id.* at A7-A8.
[592] November 2019 Regional Haze Four-Factor Analysis for Oxy Indian Basin Gas Plant at 1-2.
[593] *Id.*
[594] *Id.* at Appendix B Cost Analysis Calculations.

rate.[595] The current bank prime rate is 3.25%.[596] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[597] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[598] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

B. Natural Gas Simple Cycle Solar Centaur 40-4002 Turbines (Units ES-06/07, ES-08/09, and ES-10/11)

The combustion turbines evaluated for controls at the Indian Basin Gas Plant are all Solar Centaur turbines that were manufactured in 1980.[599] The turbines have a permitted capacity of 4000 hp (Units ES-06/07 and ES-08/09) and 4700 hp (Unit ES-10/11).[600] The units each are either routed to a heat recovery generator or a bypass stack.[601] Units ES-06/07 and ES-08/09 are each subject to a NOx limit of 15.4 lb/hr and 67.4 tpy, and Unit ES-10/11 is subject to a 23.7 lb/hr NOx limit and 104.0 tpy.[602]

Oxy only evaluated one control technology for the combustion turbines: SoLoNOx combustion technology. Oxy did not evaluate SCR. Yet, SCR is a technically feasible control technology for combustion turbines.

1. Evaluation of SoLoNOx for Solar Centaur Turbines at Indian Basin Gas Plant

Oxy states that SoLoNOx is available for the existing Solar Centaur combustion turbines, but it would require the 4002 turbines at Units ES-06/07 and ES-08/09 to be uprated to model 4702 to support the SoLoNOx technology.[603] Oxy states that such controls could reduce NOx to 25

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595 EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
596 https://www.federalreserve.gov/releases/h15/.
597 https://fred.stlouisfed.org/series/DPRIME.
598 December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.
599 Title V Operating Permit No. P103-R3, OXY USA WTP Limited Partnership Indian Basin Gas Plant, 11/1/2019, at A7.
600 *Id.*
601 *Id.*
602 *Id.* at A10.
603 November 2019 Regional Haze Four-Factor Analysis for Indian Basin Gas Plant at 2-3.

ppm.[604] Based on a comparison to Oxy's reported recent testing data for the units, SoLoNOx would reduce NOx by 75% at Units ES-06/07 and ES-08/09 and by 84% at Unit ES-10/11. It also must be noted that Oxy's capital cost estimates for installation of SoLoNOx at Units ES-06/07 and ES-08/09 (Solar Centaur T4002 turbines) are significantly higher than the costs to upgrade the same model turbines at Kutz Canyon Gas Plant. Specifically, Units 1-6 at Kutz Canyon Gas Plant are the same model turbines (Solar Centaur T4002) and would also need to be uprated to model T4702 with the installation of SoLoNOx.[605] Yet, Harvest Four Corners identified the capital cost for SoLoNOx at Units 1-6 of the Kutz Canyon facility as $467,400 with annual operations and maintenance costs of $22,500[606] whereas Oxy identified the capital cost for SoLoNOx at the same model turbines at Units ES-06/07 and ES-08/09 three times as much at $1,510,295 and with a higher operations and maintenance cost of $30,407 per year.[607]

While Oxy submitted supplemental information to NMED in a February 2020 submittal, the supplemental information appears to be for a different turbine model and also is from four years ago. Specifically, in response to NMED's request for the vendor specifications for the SoLoNOx costs and emission rate guarantee, Oxy submitted a sheet on "Predicted Emission Performance" for SoLoNOx at a Centaur 40-4700S turbine with a NOx emission rate of 42 ppmvd and submitted cost data as confidential business information for a "similar unit that was installed at the facility."[608] Yet, the turbines being reviewed in this four-factor analysis are of a different model and of a model for which a 25 ppm NOx emission rate was evaluated for SoLoNOx. NMED must collect more current cost information as to why SoLoNOx at the combustion turbines currently being evaluated for controls at Indian Basin Gas Plant would cost three times as much at the Indian Basin Solar Centaur T4002 gas turbines compared to the Kutz Canyon Solar Centaur T4002 gas turbine

In terms of the life of SoLoNOx controls in the cost effectiveness analyses, Oxy's analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[609] In the table below, we revised Oxy's cost effectiveness analyses of SoLoNOx were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate.

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[604] *Id.*

[605] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Gas Plant at 2-3.

[606] *Id.* at Appendix B (pdf 30 of document).

[607] November 2019 Regional Haze Four-Factor Analysis for Indian Basin Gas Plant at Appendix B (pdf pages 21-22 of document).

[608] February 2020 Four-Factor Addendum for Oxy Indian Basin Gas Plant at pdf page 3 and at Appendix A. Cost data in Appendix B is not publicly available.

[609] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

Table 37. Revised Cost Effectiveness of SoLoNOx at Units ES-06/07, ES-08/09, and ES-10/11 of the Indian Basin Gas Plant, to Reflect a 4.7% Interest Rate and a 25-Year Life

Unit	Oxy's Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	Oxy's Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25 Year Life
ES-06/07	$156,787	$3,809/ton	$134,367	$3,265/ton
ES-08/09	$156,787	$4,132/ton	$134,367	$3,542/ton
ES-10/11	$147,290	$1,834/ton	$127,096	$1,582/ton

Thus, the cost effectiveness of SoLoNOx at the Solar Centaur turbines based on Oxy's capital cost of SoLoNOx should be in the range of $1,582/ton to $3,542/ton assuming a more appropriate 25-year life at lower interest rate. However, assuming that the costs of SoLoNOx are instead the same as the capital and operating and maintenance costs for SoLoNOx (including uprating of the turbines) of the same model turbine (Solar T4002) at the Kutz Canyon plant, the cost effectiveness of SoLoNOx at Units ES-06/07 and 08/09 would be $1,328/ton at Unit ES-06/07 and $1,441/ton at Unit ES-08/09. It is thus imperative that NMED determine why Oxy's cost estimates for SoLoNOx at these units are so much more expensive as the costs for controls (and turbine uprates) at the same model turbines as Units 1-6 of the Kutz Canyon Gas Plant.

2. Evaluation of SCR for the Solar Centaur Combustion Turbines at the Indian Basin Gas Plant

Oxy did not evaluate SCR as a control option for any of the combustion turbines at Indian Basin Gas Plant. Oxy acknowledged that Solar Turbines indicated that SCR is an available technology for the Solar Centaur turbines at Indian Basin Gas Plant, but Oxy determined that the additional power demands of SCR make the controls infeasible because the power at the plant would "need to be upgraded significantly and re-designed in order to power the SCR controls."[610] If the power at the plant would need to be upgraded to accommodate SCR, that should be evaluated as part of the cost of SCR rather than deem the control as technically infeasible. Further, NMED should request information from Oxy to determine whether the power would need to be upgraded for SCR systems at just one combustion turbine, or if the company's claim of power supply upgrades apply to SCR systems installed at all three combustion turbines. SoLoNOx at Unit ES-10/11 is very cost effective and will reduce NOx by 84%. Thus, it is likely SCR is the better control choice just for units ES-06/07 and ES-08/09, for which SoLoNOx has higher cost effectiveness values and will only result in 75% control. NMED should request that Oxy look into the option of shared SCR reactor for these two units, which could reduce electricity needs as well as reduce costs of control.

SCR would be more effective at reducing NOx at the Solar Centaur combustion turbines than SoLoNOx. As presented NPCA's Oil and Gas Four-Factor Report, NESCAUM assumed 90%

[610] November 2019 Regional Haze Four-Factor Analysis for Indian Basin Gas Plant at 2-4.

control with SCR in its 2000 Status Report to control small gas turbines down to 15 ppmv.[611] SCR at Units ES-06/07 and ES-08/09 of the Indian Basin Gas Plant should be able to at least achieve a 15 ppmv NOx limit, which reflects 85% NOx control at each unit.

Based on the fact that the combustion turbines at its Eunice Gas Plant (Units 17A, 18B, 19A, 25A, and 26A) evaluated for SCR by DCP Midstream are of similar size as the Indian Basin Gas Plant turbines, one would expect SCR to have a similar cost effectiveness. As shown in Table 9 above, the cost effectiveness SCR at the DCP Eunice Gas Plant turbines ranged from $2,600/ton to $3,800/ton (assuming a 4.7% interest rate and 25-year life). Thus, one would expect the similar (or same) model turbine and similar size units at Indian Basin Gas Plant combustion turbines to have a similar cost effectiveness of SCR to achieve 15 ppmv at 15% O_2.

Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[612] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[613] NMED should require Oxy to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

XVII. Enterprise South Carlsbad Compressor Station

The Enterprise South Carlsbad Compressor Station is a natural gas compressor station and dew point plant.[614] According to a January 2020 NMED Statement of Basis for a Title V Permit modification,[615] after compression, the gas is sent to an amine unit to remove CO2. Water is then removed from the treated gas from the amine unit by routing through a glycol dehydrator. Salable hydrocarbons are then removed. The compressed gas then has liquids removed in a three-phase separator. Dry gas is sent into a pipeline for transport. The gas stream from the three-phase separator is used as turbine fuel along with other fuel if needed from the discharge residue gas stream or the gas stream from the condensate stabilizer. The facility is located

[611] NPCA March 2020 Oil and Gas Four-Factor Report at 74-75. *See also* NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15), available at http://www.nescaum.org/documents/nox-2000.pdf/view.
[612] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.
[613] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.
[614] NMED Statement of Basis, Title V Minor Modification, Enterprise Fields Services, LLC, South Carlsbad Compressor Station, 1/10/2020, at 1.
[615] *Id.*

about 2.8 miles northwest of Loving, New Mexico in Eddy County.[616] The plant consists of two compressors driven by natural gas-fired combustion turbines, a glycol reboiler, an amine heater, tanks, and a flare, among other air emissions sources.[617]

In Enterprise's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Solar Centaur T4702 Turbines (Units 1 and 2).[618]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[619] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

Enterprise used an 8.38% interest rate in the cost analyses for the controls evaluated in its 4-factor analyses.[620] This is an unreasonably high interest rate for cost effectiveness analyses. EPA's Control Cost Manual indicates that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[621] The current bank prime rate is 3.25%.[622] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[623] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. However, in a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[624] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. Enterprise's use of an 8.38% interest rate is unreasonably high and overstates the cost effectiveness of pollution controls evaluated in the four-factor analyses.

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[616] Title V Permit No. P130-R3 issued 3/8/18 for South Carlsbad Compressor Station at A3.
[617] *Id.* at A6-A7.
[618] November 2019 Regional Haze Four-Factor Analysis for South Carlsbad Compressor Station at 1-2.
[619] *Id.*
[620] *Id.* at Section 8.0 Supporting Documentation.
[621] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[622] https://www.federalreserve.gov/releases/h15/.
[623] https://fred.stlouisfed.org/series/DPRIME.
[624] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

B. Solar Centaur T4702 Turbines (Units 1 and 2)

The combustion turbines evaluated for controls at the South Carlsbad Compressor Station are both model T4702 Solar Centaur turbines that were manufactured in 2004.[625] The turbines have a permitted capacity of 4328 hp and a heat input of 42.8 MMBtu/hr.[626] The units each power a compressor engine.[627] The units are each subject to a NOx limit of 27.0 lb/hr and 90.8 tpy.[628]

Enterprise only evaluated one control technology for the combustion turbines: SoLoNOx combustion technology. Enterprise did not evaluate SCR. Yet, SCR is a technically feasible control technology for combustion turbines.

1. Evaluation of SoLoNOx for Solar Centaur Model T4702 Turbines

Enterprise states that SoLoNOx is available for the existing Solar Centaur model T4702 combustion turbines and that the controls could reduce NOx to 25 ppm.[629] Oxy states that such controls could reduce NOx to 25 ppm.[630] According to Enterprise's Four-Factor Analysis, SoLoNOx would reduce NOx by 64% at Unit 1 and by 66% at Unit 2.[631]
In terms of the life of SoLoNOx controls in the cost effectiveness analyses, Enterprise's analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[632] In the table below, we revised Enterprise's cost effectiveness analyses of SoLoNOx were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate.

Table 38. Revised Cost Effectiveness of SoLoNOx at Units 1 and 2 of the South Carlsbad Compressor Station, to Reflect a 4.7% Interest Rate and a 25 Year Life

Unit	Enterprise's Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	Enterprise's Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25 Year Life
1	$178,387	$8,584/ton	$130,180	$6,265/ton
2	$178,387	$6,629/ton	$130,180	$4,838/ton

625 Title V Permit No. P130-R3 issued 3/8/18 for South Carlsbad Compressor Station at A6
626 *Id.*
627 *Id.*
628 *Id.* at A9.
629 November 2019 Regional Haze Four-Factor Analysis for South Carlsbad Compressor Station at 2-2.
630 *Id.*
631 *Id.* at 3-1.
632 *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

Thus, the cost effectiveness of SoLoNOx at the Solar Centaur T4702 turbines should be in the range of $4,800/ton to $6,200/ton assuming a more appropriate 25-year life at lower interest rate. The cost effectiveness of SoLoNOx at Units 1 and 2 of the South Carlsbad Compressor Station are much higher than the cost effectiveness of SoLoNOx at Unit ES-10/11 of the Indian Basin Gas Plant, despite the turbine models being the same Solar Centaur T4702 model. It appears this is due to the low 2016 emission rates of the Units 1 and 2 at the South Carlsbad Compressor Station. As discussed in Section I.B.1. of this report, it is imperative that NMED ensure that the emissions considered as baseline emission for cost effectiveness analyses be a reasonable estimate of current and future NOx emissions. The 2016 emissions reported by Enterprise for Units 1 and 2 are less than half of the NOx emission limits for the units, despite the units both operating 8,544 hours in 2016 (or 97.2% of the available hours in a year). These low 2016 NOx emissions either reflect the need to reduce the allowable emission limits for the units to more accurately reflect current emissions levels or the 2016 emissions data may not have been measured when the units were operating at maximum capacity. If the baseline NOx emissions are going to make the difference for NMED as to whether a pollution control is cost effective or not (especially if that pollution control is considered to be cost effective for other similar size or same model turbines, then NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on an accurate estimate of emissions expected in 2028.

2. Evaluation of SCR for the Solar Centaur T4702 Turbines at the South Carlsbad Compressor Station

Enterprise did not evaluate SCR as a control option for the Units 1 and 2 combustion turbines. Enterprise states the South Carlsbad facility was designed and constructed without plans for installation of SCR, and that based on size estimated provided by CECO-Peerless, Enterprise determined that it is "not possible" to install SCR at Units 1 and 2 of the South Carlsbad Compressor Station.[633]

While the facility and gas turbines may not have been originally designed to have space to accommodate SCR, that is typically the case with most SCR retrofits. As such, there have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints. For example, for many large coal-fired power plants, SCR reactors have been elevated above the air preheaters. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new foundations to make way for the SCR reactor.[634] Thus, before NMED accepts a very brief claim of retrofit difficulty of SCR at any emissions unit being evaluated for reasonable progress controls, it is imperative that NMED ask Enterprise for a site plan and photos that shows whatever space constraints are being

[633] November 2019 Regional Haze Four-Factor Analysis for South Carlsbad Compressor Station at 2-3.
[634] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, , available at https://www.onepetro.org/conference-paper/SPE-66501-MS.

claimed, and that NMED ask Enterprise to consult with SCR vendors for options for SCR installation at the gas turbines of South Carlsbad Compressor Station. In addition, there may be other options for the location of the SCR system. Depending on the proximity of the gas turbines, it is possible that one SCR reactor could be used by both Units 1 and 2, which would reduce costs and potentially be easier to install at the site. NMED must require all possibilities for SCR installation be evaluated and documented by Enterprise. The state must not simply discount this highly effective NOx control based on a claim of some retrofit difficulty.

SCR would be more effective at reducing NOx at the South Carlsbad combustion turbines than SoLoNOx. As presented NPCA's Oil and Gas Four-Factor Report, NESCAUM assumed 90% control with SCR in its 2000 Status Report to control small gas turbines down to 15 ppmv.[635] That would reflect a 78% reduction in NOx emissions at Units 1 and 2. However, because SCR can achieve NOx reductions of 90%, SCR could be even more effective at reducing NOx from these units.

Based on the fact that the combustion turbines at its Eunice Gas Plant (Units 17A, 18B, 19A, 25A, and 26A) evaluated for SCR by DCP Midstream are of similar size as the South Carlsbad Compressor Station turbines, one would expect SCR to have a similar cost effectiveness. As shown in Table 9 above, the cost effectiveness SCR at the DCP Eunice Gas Plant turbines ranged from $2,600/ton to $3,800/ton (assuming a 4.7% interest rate and 25-year life). Thus, one would expect the similar (or same) model turbine and similar size units at Indian Basin Gas Plant combustion turbines to have a similar cost effectiveness of SCR to achieve 15 ppmv at 15% O_2.

Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[636] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[637] NMED should require Enterprise to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

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[635] NPCA March 2020 Oil and Gas Four-Factor Report at 74-75. *See also* NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15), available at http://www.nescaum.org/documents/nox-2000.pdf/view.

[636] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.

[637] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.

XVIII. El Paso Natural Gas Company – Blanco Compressor Station A

The El Paso Natural Gas Company, LLC. (EPNG) Blanco Compressor Station A is located in San Juan County. NMED has described the facility processes as follows:

The Blanco Compressor Station A is a natural gas compressor station that compresses natural gas for the purpose of transportation to another facility or a major transportation pipeline.[638]

According to the permit, the plant includes 14 2-stroke lean-burn reciprocating internal combustion engines (RICE).[639] In EPNG's four-factor submittal, the company evaluated air pollution controls for these units:

- Cooper-Bessemer 2SLB RICE GMV10-TF: Units A01 through A14.[640]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[641] The following provides a review of the company's four-factor analyses.

A. Units A01 through A14: Cooper-Bessemer GMV10-TF 2-Stroke Lean-Burn Compressor Engines

Units A01 through A14 are 2-stroke lean-burn RICE that were constructed in 1953, each with a capacity of 943 hp.[642] The units each have an hourly NOx limit of 21.9 lb/hr and an annual NOx limit of 95.97 tpy.[643]

1. Use of Low Emission Combustion Technology

EPNG presents three options for reducing NOx emissions from these compressor engines, with varying low emission combustion (LEC) control techniques to meet NOx emission levels of 3 g/hp-hr, 1 g/hp-hr, and 0.5 g/hp-hr. Uncontrolled NOx emissions (tpy) are based on 2016 emissions. The 2016 actual emissions for these units and the allowable NOx emission rates are shown in the table below.[644]

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[638] Title V Operating Permit P048-R3 for Blanco Compressor Station A at 4.
[639] *Id.* at 6-7.
[640] October 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Blanco Compressor Station A at 5.
[641] *Id.* at 3.
[642] Title V Operating Permit P048-R3 for Blanco Compressor Station A at 6-7.
[643] *Id.* at 8.
[644] October 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Blanco Compressor Station A at 5.

Table 39. EPNG Blanco Compressor Station A 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	Allowable NOx Emissions [tpy]	2016 NOx Emissions [tpy]
A01	943	95.97	73.711
A02	943	95.97	0.025
A03	943	95.97	54.915
A04	943	95.97	1.093
A05	943	95.97	3.081
A06	943	95.97	0.613
A07	943	95.97	65.341
A08	943	95.97	0.019
A09	943	95.97	27.382
A10	943	95.97	0.019
A11	943	95.97	48.253
A12	943	95.97	0.016
A13	943	95.97	82.061
A14	943	95.97	0.019

It appears that many of these units operate infrequently, with several emitting less than 1 tpy in 2016. NMED should request more information on the typical operating schedules for these engines to ensure that EPNG's four-factor analysis is based on usage that is expected in 2028.

EPNG's four-factor analysis is based on detailed cost estimates for retrofitting these units with LEC technologies; control costs include capital costs and net annual costs (annual recurring costs).[645] EPNG does not provide any details on the source of the cost information included in the four-factor analysis; we assume they represent current costs (2019$). These cost estimates are high, at $138—$217/hp, compared to other capital cost estimates for LEC controls at other similar engines.[646] EPNG presents cost effectiveness, in dollars per ton of NOx reduced, ranging from $32K/ton to as high as $2.9M/ton.[647] However, these cost effectiveness figures do not take into account the annualized costs over the lifetime of the controls, they are simply the total per unit capital cost divided by the NOx emissions reductions from 2016 emissions. The following three tables present the cost effectiveness based on EPNG's capital cost estimates—for Options 1, 2, and 3—annualized over the life of the controls. Note, this updated analysis uses an interest rate of 4.7%, reflective of current and likely near future interest

[645] *Id.* at 4 and 10.

[646] *See, e.g.,* Four-Factor analyses for Saunders Gas Plant (Cooper-Bessemer 2SLB RICE at $90-$138/hp), Roswell Compressor Station No. 9 (Cooper-Bessemer 4SLB RICE at $90/hp), and Jal No. 3 (Cooper-Bessemer 2SLB RICE at $123/hp).

[647] *Id.*

rates.[648] Further note, the LEC controls are assumed to last 25 years, consistent with other cost effectiveness analyses submitted to NMED for LEC controls.[649]

Table 40. Cost Effectiveness of LEC at Uncontrolled Blanco Compressor Station A Units A01 through A14 for Option 1 (3 g/hp-hr), Assuming a 4.7% Interest Rate and a 25-Year Life

Unit	Capital Cost of LEC to Reduce NOx Option 1 3 g/hp-hr [assuming 2019$]	Total Annualized Costs	NOx Removed, tpy Based on 2016 Source Data	Cost Effectiveness of LEC at 3 g/hp-hr [2019$], $/ton
A01	$1,884,728	$129,734	52.718	$2,461
A02	$1,884,728	$129,734	0.018	$7,207,430
A03	$1,884,728	$129,734	39.275	$3,303
A04	$1,884,728	$129,734	0.782	$165,900
A05	$1,884,728	$129,734	2.204	$58,863
A06	$1,884,728	$129,734	0.439	$295,521
A07	$1,884,728	$129,734	46.732	$2,776
A08	$1,884,728	$129,734	0.014	$9,266,695
A09	$1,884,728	$129,734	19.584	$6,624
A10	$1,884,728	$129,734	0.014	$9,266,695
A11	$1,884,728	$129,734	34.511	$3,759
A12	$1,884,728	$129,734	0.012	$10,811,145
A13	$1,884,728	$129,734	58.690	$2,210
A14	$1,884,728	$129,734	0.014	$9,266,695

Table 41. Cost Effectiveness of LEC at Uncontrolled Blanco Compressor Station A Units A01 through A14 for Option 2 (1 g/hp-hr), Assuming a 4.7% Interest Rate and a 25-Year Life

Unit	Capital Cost of LEC to Reduce NOx Option 2 1 g/hp-hr [assuming 2019$]	Total Annualized Costs	NOx Removed, tpy Based on 2016 Source Data	Cost Effectiveness of LEC at 1 g/hp-hr [2019$], $/ton
A01	$2,975,000	$204,782	66.713	$3,070
A02	$2,975,000	$204,782	0.022	$9,308,261
A03	$2,975,000	$204,782	49.701	$4,120
A04	$2,975,000	$204,782	0.989	$207,059
A05	$2,975,000	$204,782	2.789	$73,425
A06	$2,975,000	$204,782	0.555	$368,976
A07	$2,975,000	$204,782	59.138	$3,463

[648] As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.
[649] See 2019 Four-Factor submittals for Roswell Compressor Station and Jal No. 3 which both assume 25-year life of controls for LEC.

Unit	Capital Cost of LEC to Reduce NOx Option 2 1 g/hp-hr [assuming 2019$]	Total Annualized Costs	NOx Removed, tpy Based on 2016 Source Data	Cost Effectiveness of LEC at 1 g/hp-hr [2019$], $/ton
A08	$2,975,000	$204,782	0.017	$12,045,984
A09	$2,975,000	$204,782	24.783	$8,263
A10	$2,975,000	$204,782	0.017	$12,045,984
A11	$2,975,000	$204,782	43.673	$4,689
A12	$2,975,000	$204,782	0.015	$13,652,116
A13	$2,975,000	$204,782	74.271	$2,757
A14	$2,975,000	$204,782	0.017	$12,045,984

Table 42. Cost Effectiveness of LEC at Uncontrolled Blanco Compressor Station A Units A01 through A14 for Option 3 (0.5 g/hp-hr), Assuming a 4.7% Interest Rate and a 25-Year Life

Unit	Capital Cost of LEC to Reduce NOx Option 3 0.5 g/hp-hr [assuming 2019$]	Total Annualized Costs	NOx Removed, tpy Based on 2016 Source Data	Cost Effectiveness of LEC at 0.5 g/hp-hr [2019$], $/ton
A01	$2,804,837	$193,069	70.212	$2,750
A02	$2,804,837	$193,069	0.023	$8,394,291
A03	$2,804,837	$193,069	52.308	$3,691
A04	$2,804,837	$193,069	1.041	$185,465
A05	$2,804,837	$193,069	2.935	$65,781
A06	$2,804,837	$193,069	0.584	$330,597
A07	$2,804,837	$193,069	62.240	$3,102
A08	$2,804,837	$193,069	0.018	$10,726,039
A09	$2,804,837	$193,069	26.082	$7,402
A10	$2,804,837	$193,069	0.018	$10,726,039
A11	$2,804,837	$193,069	45.963	$4,201
A12	$2,804,837	$193,069	0.016	$12,066,794
A13	$2,804,837	$193,069	78.166	$2,470
A14	$2,804,837	$193,069	0.018	$10,726,039

For many of these units, LEC controls can be cost effective for reducing NOx emissions to emission rates as low as 0.5 g/hp-hr. NMED must request a revised four-factor analysis from EPNG for the Blanco Compressor Station A that includes the annualization of costs. Also, NMED should request additional information on the usage of these engines to determine if the units are consistently used as in 2016 or if usage varies from year to year. NMED must ensure that the cost effectiveness analyses for LEC evaluated for the company's four-factor analyses are based on a more comprehensive representation of emissions reduction and operating hours expected in 2028.

2. Use of SCR

EPNG did not evaluate SCR for Units A01 through A14 primarily because it claimed that it was not technically feasible for this engine type.[650] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly because EPNG has not found LEC to be a cost effective NOx reduction strategy for some of these units.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[651]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[652] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[653] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

XIX. Transwestern Pipeline Company Roswell Compressor No. 9

The Transwestern Pipeline Company (Transwestern) Roswell Compressor Station No. 9 is a natural gas compressor station located about 5 miles north of Roswell, New Mexico in Chaves

[650] October 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Blanco Compressor Station A at 9.
[651] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[652] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[653] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

County.[654] The plant consists of two natural gas-fired four-stroke lean-burn compressor engines compressors and a natural gas-fired rich burn engine used as a generator, as well as several tanks and other emissions sources.[655] The compressor station also has two electric-driven compressor engines with no associated air emissions.[656] In Transwestern's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Two Four-Stroke Lean-Burn RICE (Units 903 and 904).[657]

The rich burn generator engine is used as an emergency generator and operates less than 100 hours per year, and so was not evaluated for controls.[658] The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses. The following provides a review of the company's four-factor analyses.

A. Lean Burn Natural Gas-Fired Compressor Engines (Units 903 and 904)

The primary sources of NOx emissions at the Roswell Compressor Station No. 9 are two four-stroke lean burn natural gas-fired RICE (Units 903 and 904). The engines are both 4,500 hp Cooper-Bessemer LSV-16G compressor engines used for transportation of natural gas.[659] The engines were constructed in 1959, and are subject to allowable emission limits of 125 lb/hr and 547.5 tpy each.[660]

According to documentation submitted with the four-factor analysis, the 2016 emissions and operating hours used as baseline were as follows:

Table 43. Units 903 and 904 of Roswell Compressor Station No. 9 2016 Emissions and Operating Hours[661]

Unit No.	NOx Emission Rate, lb/hr	2016 Operating Hours	NOx Emissions, tpy
903	37.19 (Tested)	3,607	67.07
904	125 (PTE)	971	60.69

The source's Title V renewal application indicates that the allowable annual number of operating hours for Units 903 and 904 was increased from 6,620 to 8,760, which was the

[654] Title V Permit No. P154-R4, Roswell Compressor Station No. 9, 9/28/2018, at A3.
[655] *Id.* at A6.
[656] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[657] *Id.* at 2.
[658] *Id.*
[659] *Id.*
[660] Title V Permit No. P154-R4, Roswell Compressor Station No. 9, 9/28/2018, at A7.
[661] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, Appendix A at 1. Apparently, the company only had NOx emissions test data for Unit 903.

allowable number of hours in Permit No. P154-R2M1.[662] So presumably the 2016 operating hours are lower than what might be expected in current and future years for these units, especially for Unit 904. And, in fact, a review of the facility's NOx emissions from 2016 through 2019 show an increase in NOx emissions as shown in the table below.

Table 44. Roswell Compressor Station No. 9 NOx Emissions 2016-2019, as Presented in NMED's Emissions Analysis Tool

2016	2017	2018	2019
74.4 tons	185.5 tons	136.5 tons	436.8 tons

NOx emissions are over five times higher in 2019 than they were in 2016. And NOx emissions in all years since 2016 are significantly higher. And it is safe to assume that the bulk of those NOx increases are coming from the Units 903 and 904 lean burn compressor engines, because the only other sources of NOx emissions at the compressor station are Unit 921 (four-stroke rich burn emergency generator engine operating less than 100 hours per year) and two thermal oxidizers. These three NOx sources are limited to a combined total NOx emissions of 27.54 tons per year.[663] Even if we assume that these three units emitted NOx at their allowable emissions of 27.54 tons per year total, that means over 400 tons of NOx were emitted in 2019 by Units 903 and 904, rather than the 127.76 tons per year in total assumed in Transwestern's four-factor cost effectiveness analysis.[664] NMED must ensure that Transwestern's cost effectiveness analysis of controls is based on emissions expected in 2028. Given the significant increases in emissions since 2016 and the permitted increased levels of operation, 2016 emissions should not be used as baseline emissions in the company's cost effectiveness analysis for controls. Use of more recent data would result in more favorable cost effectiveness values because of the increased reduction in NOx that would occur from more recent emissions levels.

1. Evaluation of Low Emissions Combustion for Units 903 and 904

Transwestern assumes a controlled NOx emission rate from LEC retrofits on units 903 and 904 of 2.5 g/hp-hr.[665] For unit 903, Transwestern reports that this represents a 33% reduction from baseline NOx emission rates that are based on the 2016 emissions inventory.[666] For unit 904, Transwestern reports that this represents an 80% reduction from the unit's permitted NOx emission rate; according to Transwestern, "permitted hourly NO_X emission rates were used for Unit 904 in this analysis due to the 2016 emissions inventory showing lower NO_X emission rates

[662] February 1, 2017 Title V Operating Permit Renewal Application, Permit P154-R3M1 Transwestern Pipeline Company, LLC Roswell Compressor Station No. 9 Section 3 Page 2.
[663] *See* Title V Permit No. P154-R4, Roswell Compressor Station No. 9, 9/28/2018, at A8.
[664] Note, Transwestern's four-factor analysis is based on PTE emissions for unit 904. Even so, actual emissions in 2019 are much higher that what was used in the company's four-factor analysis.
[665] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Roswell Compressor Station No. 9 at 3 and Appendix A.
[666] *Id.* Appendix A.

than what was feasible to obtain by the engine vendor."[667] The permitted maximum hourly NOx emission rate of 125.0 lb/hr for these units is significantly higher than the 2016 emissions inventory data used for baseline emissions, even for unit 903. The allowable hourly NOx emission rate is equivalent to 12.6 g/hp-hr for these 4,500 hp engines. The source's Title V renewal application notes that the NOx emission factors are based on the permitted hourly rate in Permit No. P154-R2M1; it's not clear if the rates are based on stack testing or AP-42 emission factors but since all other emission factors (besides NOx) are identified as EPA AP-42 emission factors it's assumed that the permitted hourly rates are either based on stack tests or are source requested limits.[668] So for both units, emissions reductions to meet a controlled NOx rate of 2.5 g/hp-hr, based on a baseline emission rate that is reflective of the units' allowable emission rate, represents an 80% reduction in NOx emissions.

In January 2020, Transwestern submitted additional information in response to a request from NMED, including the specific technologies included in the quote from Cooper Machinery for LEC upgrades that lower NOx emissions to 2.5 g/hp-hr (e.g., precombustion chambers, turbocharger upgrades, larger intercoolers, etc.).[669]

It's possible that the controlled emission rate with LEC for these specific engines could be even lower that 2.5 g/hp-hr. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[670] EPA's Alternative Control Techniques document for RICE includes emissions test results for Clean Burn, low-emission retrofits (with a pre-combustion chamber) for LSV model dual-fuel engines demonstrating NOx emission rates of 2.0 g/hp-hr and as low as 1.27 g/hp-hr.[671] And, more generally, EPA's updated information on stationary RICE NOx emissions and control technologies concludes, for lean-burn engines, an emission rate of 2.0 g/bhp-hr is achievable for "new engines and most engines retrofitted with LEC technology."[672] Emissions reductions to meet a controlled NOx rate of 2 g/hp-hr, based on a baseline emission rate that is reflective of the units' allowable emission rate, represents an 84% reduction in NOx emissions.

Revising Transwestern's cost effectiveness analyses to reflect the quoted emissions reductions of 80% but based on potential operation at permitted levels for both units (not just for unit 904), results in more favorable cost effectiveness of these controls, as shown in the table below.

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[667] *Id.* at 1 and Appendix A.
[668] February 1, 2017 Title V Operating Permit Renewal Application, Permit P154-R3M1 Transwestern Pipeline Company, LLC Roswell Compressor Station No. 9 pdf page 39.
[669] January 23, 2020 Additional Information for Four Factor Analysis Roswell Compressor Station at 2.
[670] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.
[671] *See* EPA 1993 Alternative Control Techniques Document for RICE at 5-82 and 5-83.
[672] *Id.* at 4-12.

Table 45. Cost Effectiveness of LEC at Uncontrolled Roswell Compressor Station No. 9 Units 903 and 904 to Reduce NO_x Levels to 2.5 g/hp-hr, Assuming 80% Control

Unit	Size [hp]	Capital Cost of LEC [current vendor quote, assuming 2019$]	Annual O&M Costs (15% of Capital Costs) [2019$]	Total Annualized Costs of LEC to Reduce NOx to 2.5 g/hp-hr (80% NOx Reduction) [2019$]	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC [2019$], $/ton
903	4,500	$1,800,000	$270,000	$342,000	3,607	180	$1,896/ton
904	4,500	$1,800,000	$270,000	$342,000	971	49	$7,044/ton

Note, the cost effectiveness of LEC controls would be more favorable for unit 904 at higher operating hours and would be more feasible for both units if they were able to meet controlled emission rates below 2.5 g/hp-hr, which, as discussed earlier, has been demonstrated for other LEC retrofits for similar engines. NMED should request that Transwestern research other available retrofit options from additional vendors that may be able to guarantee NOx emission rates less than 2.5 g/hp-hr.

2. Evaluation of SCR for Units 903 and 904

Although Transwestern identified concerns with utilization of SCR for the lean burn engines (which included reagent injection control, exhaust temperature requirements, variations in exhaust NO/NO2 ratio, and engine oil carryover), Transwestern evaluated SCR as a NOx control option for the Units 903 and 904 engines.[673] In the May 21, 2020 Review of SCR Claims for Lean Burn Engines report, these issues and methods to resolve these concerns were addressed.[674] Transwestern said as a result of its stated concerns, LEC is the preferred control. Yet, the company's cost analysis showed that SCR was more cost effective, and it can achieve 90% NOx reduction.[675]

Transwestern appears to have used EPA's SCR Chapter of its Control Cost Manual to either estimate annual operations and maintenance costs of SCR and used a formula from the December 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines to estimate capital costs for SCR.[676]

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[673] *Id.* at 3-4.

[674] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.

[675] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 4-5 and Appendix A.

[676] December 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines at III-30.

Specifically, the NESCAUM formula which was based on only one case study for a RICE unit to "approximate" SCR capita costs for lean burn RICE is as follows:

$310,000 + ($72.7 x hp)[677]

This NESCAUM equation is twenty years old and is likely based on cost data from the 1990's. SCR has been implemented on numerous source types over the past twenty years, and the much wider-scale implementation and innovation in catalyst design has lowered the cost of SCR.[678] Yet, Transwestern's analysis escalated the capital costs developed with the above equation from the 2000 NESCAUM report by assuming the NESCAUM cost equation was based on 1994 costs and escalating to 2019, using the differences in the Consumer Price Index between 1994 and 2019.[679] EPA's Control Cost Manual cautions against escalating costs more than five years due to the potential for significant inaccuracies in price estimates.[680] EPA currently has a spreadsheet available to estimate the capital and operating costs for SCR. While the spreadsheet was developed for fossil fuel fired boilers, it can be used as an estimate for SCR at other natural gas-fired sources and, in fact, has been used oil and gas companies for several four-factor analyses submitted to NMED. Transwestern included the necessary information to be able to utilize the EPA SCR cost spreadsheet to estimate SCR costs for the Units 903 and 904 engines. Specifically, the company provided the hourly heat input in MMBtu/hr, the inlet NOx emission rate in lb/MMBtu, the engine fuel consumption in terms of Btu/hp-hr (with which the annual fuel consumption can be estimated based on the 2016 operating hours for each unit and each unit's rated horsepower of 4500), the flue gas flow rate in actual cubic feet per minute, and the SCR inlet temperature. The elevation for the location was estimated to be 3600 feet above sea level.

Using the unit-specific operating hours for 2016 and assuming 90% NOx reduction across the SCR, the cost effectiveness based on EPA's SCR spreadsheet is estimated as shown in the table below. Transwestern assumed a 25-year life of SCR, which was also assumed in the SCR cost effectiveness calculation presented below which is consistent with EPA's Control Cost Manual for the expected life of SCR at an industrial unit. For reasons discussed above in this report, a 4.7% interest rate was used rather than Transwestern's assumed 5.5% interest rate. (See, e.g., Section I.A. above).

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[677] *Id*.

[678] See EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.

[679] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, Appendix A (pdf pages 15 and 17 of report).

[680] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.

Table 46. Estimated Cost Effectiveness of SCR Using EPA's SCR Cost Spreadsheet and 2016 Operational Data for Units 903 and 904 Cooper-Bessemer LSV-16G Compressor Engines at Roswell Compressor Station No. 9 (25-Year Life, 4.7% Interest Rate), 2018 $

Unit Number	Capital Cost	Operations and Maintenance Costs	Total Annual Costs	NOx Reduced from 2016 Emissions, tpy	Cost Effectiveness
903	$1,778,670	$25,746	$150,853	60	$2,449/ton
904	$1,832,960	$26,173	$128,846	55	$2,835/ton

In comparison, Transwestern's SCR cost estimates are much higher. The table below provides the company's SCR cost estimates for comparison to Table 46 above.

Table 47. Transwestern's Cost Effectiveness of SCR for Units 903 and 904 Cooper-Bessemer LSV-16G Compressor Engines at Roswell Compressor Station No. 9 (25-Year Life, 5.5% Interest Rate), 2019 $[681]

Unit Number	Capital Cost	Operations and Maintenance Costs	Total Annual Costs	NOx Reduced from 2016 Emissions, tpy	Cost Effectiveness
903	$1,100,282	$218,527	$262,538	60	$4,376/ton
904	$1,100,282	$255,446	$299,457	55	$5,445/ton

Interestingly, EPA's SCR cost spreadsheet estimates a much higher capital cost than Transwestern's escalation of NESCAUM's capital cost equation for RICE units. But what makes most of the differences in the cost estimates is Transwestern's operations and maintenance costs. A review of the company's cost data sheet found two significant errors that lead to the overstatement of operations and maintenance costs. First, an error was made in the calculation of catalyst volume by Transwestern, due to an error in the formula used for the NOx efficiency adjustment factor η_{adj}. The formula for η_{adj} in EPA's Control Cost Manual chapter for SCR is:

$$\eta_{adj} = 0.2869 + (1.058 \underline{x}\ \eta_{NOx})$$ [682]

However, Transwestern used the formula

$$\eta_{adj} = 0.2869 + (1.058 \mathbf{+} \eta_{NOx})$$ [683]

Transwestern's error resulted in a significant overestimate of the volume of catalyst, in which η_{adj} is a multiplier, which then resulted in an overestimate of annual catalyst replacement costs.

[681] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, Appendix A (pdf pages 13-14 of report).
[682] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 61 (Equation 2.23).
[683] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, Appendix A (pdf pages 16 and 18 of report).

In addition, Transwestern assumed 8,760 hours per year of operation in determining annual operations and maintenance costs which significantly overstated the costs of reagent, catalyst replacement, and labor.[684]

In summary, SCR is a more cost effective NOx control for the Units 903 and 904 engines at Roswell Compressor No. 9 compared to LEC which Transwestern estimated would have a cost effectiveness of $7,000/ton to $15,000/ton.[685]

XX. Transwestern Pipeline Mountainair Compressor Station

The Transwestern Pipeline Company (Transwestern) Mountainair Compressor Station is a natural gas compressor station located in Torrance County, New Mexico. NMED has described the facility processes as follows:

> The facility is a natural gas compressor station. The station is equipped with three 4,500- horsepower (hp) Cooper-Bessemer LSV-16SG compressor engines (701-703) and two 335- hp Ingersoll-Rand PSVG-6 generator engines (721-722), a pipeline condensate storage tank (T-006), and a mist extractor (MIST).[686]

In Transwestern's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Cooper-Bessemer 4SLB RICE LSV-16G: Units 701, 702, and 703.[687]

The rich burn generator engines are equipped with NSCR and are achieving 85% reduction in NOx emissions based on recent engine performance testing.[688] The selection of the 4SLB RICE units for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses. The following provides a review of the company's four-factor analyses.[689]

A. Lean Burn Natural Gas-Fired Compressor Engines (Units 701, 702, and 703)

The primary sources of NOx emissions at the Mountainair Compressor Station are three four-stroke lean-burn natural gas-fired RICE (Units 701, 702, and 703). The engines are each 4,500 hp Cooper-Bessemer LSV-16G compressor engines used for transportation of natural gas.[690]

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[684] *Id.* at pdf pages 15-18.
[685] *Id.* at pdf page 13.
[686] Title V Permit No. P153-R3M1, Mountainair Compressor Station, 9/26/2016, at 3.
[687] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mountainair Compressor Station at 2.
[688] *Id.*
[689] *Id.* at 1.
[690] Title V Permit No. P153-R3M1, Mountainair Compressor Station, 9/26/2016, at 5-6.

The engines were constructed in 1960 (701 and 701) and 1967 (703), and are subject to allowable emission limits of 165.3 lb/hr and 724.2 tpy each.[691]

1. Baseline Emissions for Units 701, 702, and 703

According to documentation submitted with the four-factor analysis, the 2016 emissions and operating hours used as baseline were as follows:

Table 48. Units 701, 702, and 703 of Mountainair Compressor Station 2016 Emissions and Operating Hours[692]

Unit No.	2016 NOx Emission Rate, lb/hr	2016 Operating Hours	2016 NOx Emissions, tpy	NOx Allowable Emissions, tpy	NOx Allowable Emissions, lb/hr
701	59.07	1,535	45.34	724.2	165.3
702	98.03	3,116	152.73	724.2	165.3
703	100.86	4,586	231.27	724.2	165.3
TOTAL	258.0	9,237	429.34	2,172.6	495.9

The company's 2016 NOx emissions, used as baseline emissions, are significantly lower than the units' allowable emission limits of 165.3 lb/hr and 724.2 tpy each. And more recent actual emissions from the facility are also much higher.

In fact, the facility obtained a permit in 2016 that allowed for a three-fold increase in startup, shutdown, maintenance, and malfunction emissions because the facility was operating more due to increased volume of natural gas being processed at the facility.[693] Prior to 2016, NMED referred to the compressor station as a "peaking station."[694] A review of the facility's NOx emissions from 2016 through 2019 show a dramatic increase in NOx emissions as shown in the table below.

Table 49. Mountainair No. 7 Compressor Station NOx Emissions 2016-2019, as Presented in NMED's Emissions Analysis Tool

2016	**2017**	**2018**	**2019**
436.6 tons	449.2 tons	1,048.1 tons	932 tons

NOx emissions have more than doubled since 2016 at the Mountainair No. 7 Compressor Station. The most recent two year average NOx emissions are 990.05 tons compared to 436.6 tons of NOx emitted in the 2016 base year used in Transwestern's cost analysis. And it is safe

[691] *Id.*
[692] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mounatinair Compressor Station Appendix A at 1.
[693] *See* 9/26/2016 NMED Statement of Basis -Narrative for Title V Permit Significant Permit Modification for Mountainair No. 7 Compressor Station (Permit No. P153-R3M1) at 1.
[694] *Id.* at 3.

to assume that the bulk of those NOx increases are coming from the Units 701, 702, and 702 lean burn compressor engines, because the only other sources of NOx emissions at the compressor station are Units 721 and 722 (four-stroke rich burn generator engines) that are limited to a combined total NOx emissions of 90.9 tons per year.[695] If we assume that Units 721 and 722 emitted NOx at their allowable emissions of 90.9 tons per year total (which is not likely to occur),[696] that means at least 899.15 tons of NOx were emitted on average over 2018 to 2019 by Units 701, 702, and 703, rather than the 429.34 tons per year in total assumed in Transwestern's four-factor cost effectiveness analysis. NMED must ensure that Transwestern's cost effectiveness analysis of controls is based on emissions expected in 2028. Given the significant increases in emissions since 2016 and the permitted increased levels of operation, 2016 emissions should not be used as baseline emissions in the company's cost effectiveness analysis for controls. Use of more recent data would result in lower cost effectiveness values because of the increased reduction in NOx that would occur from more recent emissions levels.

2. Evaluation of Low Emissions Combustion for Units 701, 702, and 703

Transwestern assumes a controlled NOx emission rate from LEC retrofits on units 701, 702, and 703 of 2.5 g/hp-hr.[697] This represents a 58% (unit 701) and 75% (units 702 and 703) NOx emissions reduction from baseline NOx emission rates that are based on the 2016 emissions inventory.[698] The permitted maximum hourly NOx emission rate of 165.3 lb/hr for these units is significantly higher than the 2016 emissions inventory data used for baseline emissions. The allowable hourly NOx emission rate is equivalent to 16.7 g/hp-hr for each of these 4,500 hp engines. No test data are provided for these units and the source's recent Title V modification application does not specify the basis for the source's allowable NOx emission limits.[699] For both units, emissions reductions to meet a controlled NOx rate of 2.5 g/hp-hr, based on a baseline emission rate that is reflective of the units' allowable emission rate, represents an 85% reduction in NOx emissions.

It's possible that the controlled emission rate with LEC for these specific engines could be even lower that 2.5 g/hp-hr. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[700] EPA's

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[695] *See* 9/26/2016 Title V Operating Permit No. P153-R3M1 for Mountainair Compressor Station (Station No. 7) at 3 and at 5-7.

[696] For example, in 2016, Units 701, 702, and 703 emitted 429.34 tons (based on what was reported for these units' 2016 emissions in the Mountainair No 7 Compressor Station Four-Factor Analysis in Appendix A). The total reported NOx emissions as shown in Table 49 above were 436.6 tons, which would mean Units 721 and 722 only emitted 7.26 tons of NOx in 2016.

[697] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mounatinair Compressor Station at 3 and Appendix A.

[698] *Id.* Appendix A.

[699] *See* March 3, 2016 Title V Operating Permit Application for Significant Modification, Permit P153-R3 Transwestern Pipeline Company, LLC Mountainair Compressor Station Section 6, Page 4.

[700] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.

Alternative Control Techniques document for RICE includes emissions test results for Clean Burn, low-emission retrofits (with a pre-combustion chamber) for LSV model dual-fuel engines demonstrating NOx emission rates of 2.0 g/hp-hr and as low as 1.27 g/hp-hr.[701] And, more generally, EPA's updated information on stationary RICE NOx emissions and control technologies concludes, for lean-burn engines, an emission rate of 2.0 g/bhp-hr is achievable for "new engines and most engines retrofitted with LEC technology."[702] Emissions reductions to meet a controlled NOx rate of 2 g/hp-hr, based on a baseline emission rate that is reflective of the units' allowable emission rate, represents an 88% reduction in NOx emissions. Revising Transwestern's cost effectiveness analyses to reflect higher baseline emission levels that are more in line with recent NMED actual emissions data, results in more favorable cost effectiveness of these controls, as shown in the table below. This revised analysis assumes baseline emissions that are reflective of more recent NMED emissions data (e.g., 899.15 tons per year for units 701, 702, and 703 based on 2018-2019 actual emissions and assuming units 721 and 722 concurrently operated at permitted allowable levels during that time). These annual emissions are distributed equally across units 701, 702, and 703 since 2018-2019 operating hours are not known. The table below presents cost effectiveness assuming an 85% reduction in NOx emissions, which reflect reducing hourly allowable NOx emission rates to a level of 2.5 g/hp-hr.

Table 50. Cost Effectiveness of LEC at Uncontrolled Mountainair Compressor Station Units 701, 702, and 703 to Reduce NO_x Levels to 2.5 g/hp-hr, Based on 2018-2019 Baseline Emission Levels Evenly Distributed Across Units 701, 702, and 703

Unit	Size [hp]	Total Annualized Costs of LEC to Reduce NOx to 2.5 g/hp-hr [2019$]	NOx Removed, tpy	Cost Effectiveness of LEC [2019$], $/ton
701	4,500	$342,000*	255	$1,341/ton
702	4,500	$342,000*	255	$1,341/ton
703	4,500	$342,000*	255	$1,341/ton

*Quote from Cooper Machinery Services 10/17/19

Note, if units 701, 702, and 703 operate with the same distribution as in 2016 (i.e., with unit 701 operating roughly 15% of the time, unit 702 operating 35% of the time, and unit 703 operating 50% of the time), the cost effectiveness would range from $900–$3,000/ton. And the cost effectiveness of LEC controls would be even more favorable, under any operating scenario, if LEC at these units were able to meet controlled emission rates below 2.5 g/hp-hr, which, as discussed earlier, has been demonstrated for other LEC retrofits for similar engines. NMED should request that Transwestern research other available retrofit options from additional

[701] *See* EPA 1993 Alternative Control Techniques Document for RICE at 5-82 and 5-83.
[702] *Id.* at 4-12.

vendors that may be able to guarantee NOx emission rates less than 2.5 g/hp-hr for these engines.

3. Use of SCR

Transwestern also evaluated SCR as a control for the four-stroke lean burn engines at Mountainair Compressor Station (Units 701, 702, and 703). The company did identify concerns with applicability of SCR to the two-stroke lean burn units including reagent injection control, exhaust temperature requirements, variations in the exhaust NO/NO_2 ratio, and engine oil carryover harming the SCR catalyst.[703] In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[704]

Irrespective of the company's concerns with applicability of SCR to the lean burn engines, Transwestern did conduct a cost effectiveness evaluation for SCR at Units 701, 702, and 703 assuming a target NOx emission rate of 0.060 to 1.02 g/hp-hr which purported reflects 90% reduction from current NOx emission levels.[705] Specifically, the company estimated the cost effectiveness of SCR at Unit 701 as $6,596/ton, at Unit 702 as $2,114/ton, and at Unit 703 as $1,372/ton.[706] The company's analyses show that SCR is more cost effective than LEC. Yet, these cost effectiveness values are in error and true cost effectiveness of SCR would be even lower, as discussed below.

One reason the cost effectiveness values are likely lower is because Transwestern relied on 2016 emissions as baseline emissions, but 2016 emissions were much lower than more recent years' emissions as discussed earlier.

Transwestern appears to have used a 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines to estimate capital costs for SCR.[707] Specifically, the NESCAUM formula which was based on only one case study for a RICE unit to "approximate" SCR capita costs for lean burn RICE is as follows:

$310,000 + ($72.7 x hp)[708]

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[703] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mountainair Compressor Station at 3.
[704] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[705] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mountainair Compressor Station at Appendix A.
[706] *Id.* at Appendix B.
[707] *Id.* at 8. *See also* December 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines at III-30.
[708] *Id*.

This NESCAUM equation is twenty years old and is likely based on cost data from the 1990's. SCR has been implemented on numerous source types over the past twenty years, and the much wider-scale implementation and innovation in catalyst design has lowered the cost of SCR.[709] Yet, Transwestern's analysis escalated the capital costs developed with the above equation from the 2000 NESCAUM report by assuming the NESCAUM cost equation was based on 1994 costs and escalating to 2019, using the differences in the Consumer Price Index between 1994 and 2019.[710] EPA's Control Cost Manual cautions against escalating costs more than five years due to the potential for significant inaccuracies in price estimates.[711]

EPA currently has a spreadsheet available to estimate the capital and operating costs for SCR. While the spreadsheet was developed for fossil fueled fired boilers, it can be used as an estimate for SCR at other natural gas-fired sources and, in fact, has been used oil and gas companies for several four-factor analyses submitted to NMED. Transwestern included the necessary information to be able to utilize the EPA SCR cost spreadsheet to estimate SCR costs for the Units 701-703 engines. Specifically, the company provided the hourly heat input in MMBtu/hr, the inlet NOx emission rate in lb/MMBtu, the engine fuel consumption in terms of Btu/hp-hr (with which the annual fuel consumption can be estimated based on the 2016 operating hours for each unit and each unit's rated horsepower of 4500), the flue gas flow rate in actual cubic feet per minute, and the SCR inlet temperature. The elevation for the location was estimated to be 6,519 feet above sea level (the elevation of the city of Mountainair, New Mexico)

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Using the unit-specific operating hours for 2016 and assuming 90% NOx reduction across the SCR, the cost effectiveness based on EPA's SCR spreadsheet is estimated as shown in the table below. Transwestern assumed a 25-year life of SCR, which was also assumed in the SCR cost effectiveness calculation presented below which is consistent with EPA's Control Cost Manual for the expected life of SCR at an industrial unit. For reasons discussed above in this report, a 4.7% interest rate was used rather than Transwestern's assumed 5.5% interest rate. (See, e.g., Section I.A. above).

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[709] See EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.

[710]October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mountainair Compressor Station at Appendix B.

[711] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.

Table 51. Estimated Cost Effectiveness of SCR Using EPA's SCR Cost Spreadsheet and 2016 Operational Data for Units 701, 702, and 703 at Mountainair Compressor Station No. 7 (25-Year Life, 4.7% Interest Rate), 2018 $

Unit Number	Capital Cost	Operations and Maintenance Costs	Total Annual Costs	NOx Reduced from 2016 Emissions, tpy	Cost Effectiveness
701	$1,996,770	$22,760	$162,886	41	$3,989/ton
702	$1,996,397	$36,662	$176,761	137	$1,286/ton
703	$1,886,138	$44,591	$177,098	208	$850/ton

In comparison, Transwestern's SCR cost estimates are much higher. The table below provides the company's SCR cost estimates for comparison to Table 51 above.

Table 52. Transwestern's Cost Effectiveness of SCR for Units 701, 702, and 703 at Mountainair Compressor Station No. 7 (25-Year Life, 5.5% Interest Rate), 2019 $[712]

Unit Number	Capital Cost	Operations and Maintenance Costs	Total Annual Costs	NOx Reduced from 2016 Emissions, tpy	Cost Effectiveness
701	$1,100,282	$225,152	$269,152	40.81	$6,596/ton
702	$1,100,282	$246,513	$290,525	137.46	$2,114/ton
703	$1,100,282	$241,474	$285,485	208.14	$1,372/ton

Interestingly, EPA's SCR cost spreadsheet estimates a much higher capital cost than Transwestern's escalation of NESCAUM's capital cost equation for RICE units. But what makes most of the differences in the cost estimates is Transwestern's operations and maintenance costs. A review of the company's cost data sheet found two significant errors that lead to the overstatement of operations and maintenance costs. First, an error was made in the calculation of catalyst volume by Transwestern, due to an error in the formula used for the NOx efficiency adjustment factor η_{adj}. The formula for η_{adj} in EPA's Control Cost Manual chapter for SCR is:

$$\eta_{adj} = 0.2869 + (1.058 \ \underline{\mathbf{x}} \ \eta_{NOx})$$ [713]

However, Transwestern used the formula

$$\eta_{adj} = 0.2869 + (1.058 \ \mathbf{+} \ \eta_{NOx})$$ [714]

[712] October 2019 Regional Haze Four-Factor Analysis for Mountainair Compressor Station No. 7, Appendix A (pdf page 12 of report).
[713] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 61 (Equation 2.23).
[714] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, Appendix A (pdf pages 14, 16, and 18 of report).

Transwestern's error resulted in a significant overestimate of the volume of catalyst, in which η_{adj} is a multiplier, which then resulted in an overestimate of annual catalyst replacement costs.

In addition, Transwestern assumed 8,760 hours per year of operation in determining annual operations and maintenance costs which significantly overstated the costs of reagent, catalyst replacement, and labor.[715]

With these deficiencies in Transwestern's cost analysis along with its use of 2016 emissions to define the NOx emissions reduced with SCR, Transwestern's cost effectiveness values for SCR are greatly overstated. While the increased hours of operation would mean increased operational costs, the capital cost of SCR would remain the same. And the annual reduction in NOx emissions would be much greater (i.e., 90% control from 2018-2018 average NOx emissions versus 90% control from the much lower 2016 NOx emissions). Thus, with more recent NOx emissions used as baseline, SCR will be even more cost effective than shown above.

In summary, SCR is a more cost effective NOx control for the Units 701, 702, and 703 compared to LEC, which Transwestern estimated would have a cost effectiveness of $1,961/ton to $13,002/ton.[716] However, if more recent emissions data are used, the cost effectiveness of LEC would also be much lower than estimated by Transwestern at $1,341/ton.

XXI. Transwestern Pipeline Company – Corona Compressor Station

The Transwestern Pipeline Company, LLC. (Transwestern) Corona Compressor Station was not a facility for which NMED requested a four-factor analysis, yet the facility has a Q/d value (based on 2014 emissions) of 5.9. The closest Class I area to the plant is the White Mountains Wilderness, which is 60 kilometers away, according to the NMED Emissions Analysis Tool. The Corona Compressor Station is located in Lincoln County. NMED has described the facility processes as follows:

> The function of the facility is to compress natural gas. This facility receives natural gas from an upstream compressor station which goes through an inlet separator. The gas is then compressed by two (2) natural gas fired RICE compressors (units 801 and 802) and is sent to the next downstream compressor station. Two Waukesha generator engines supply electrical power to the station.[717]

According to the permit, the plant includes two 2-stroke lean-burn compressor engines, two 4-stroke rich-burn RICE, and two tanks.[718]

[715] *Id.* at pdf pages 15-18.
[716] *Id.* at pdf page 12.
[717] Title V Operating Permit P151-R3 for Corona Compressor Station at A3.
[718] *Id.* at A5.

A. Units 801 and 802: Cooper-Bessemer V-250 2-Stroke Lean-Burn Compressor Engines

Units 801 and 802 are Cooper-Bessemer V-250 2-stroke lean-burn RICE constructed in 1967 (801) and 1968 (802), each with a capacity of 5,000 hp.[719] The units each have an hourly NOx limit of 205.5 lb/hr and an annual NOx limit of 900 tpy.[720]

1. Use of Low Emission Combustion Technology

The uncontrolled allowable NOx emission rates for units 801 and 802 of 205.5 lb/hr are equivalent to 18.6 g/hp-hr for these 5,000 hp engines. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with low emission combustion (LEC) technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[721] In 2002, EPA collected data on emission rates of lean burn engines that have been retrofitted with LEC, including data from several state agencies for specific engine models.[722] Test results for eight Cooper-Bessemer V-250 engines ranged from 1.6 to 3.4 g/hp-hr, with an average controlled NOx rate of 2.9 g/hp-hr.[723] And, overall, EPA calculated the weighted average for installation of LEC technology retrofit on all of the large IC engines in the dataset to be 2.9 g/bhp-hr.[724] At this controlled emission rate, NOx emissions reductions for units 801 and 802 would be 84%. These emissions reductions could prevent up to 1,500 tons per year of NOx emissions from these two units, combined, for operation at permitted annual levels. NMED should request a four-factor analysis for these units to evaluate the cost effectiveness of controlling NOx emissions from these units with LEC to 2.9 g/hp-hr.

2. Use of SCR

SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[725]

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[719] *Id.*
[720] *Id*. at A7.
[721] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.
[722] *See* EPA Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call (October 2003) at 15, *available at:* http://www.valleyair.org/workshops/postings/2011/8-18-11-rule4702/R4702%20APPF.pdf.
[723] *Id.* Table 4.
[724] *Id.* at 25.
[725] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.

If LEC is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[726] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[727] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should consider SCR as a potentially viable control option for lean burn engines in a company's analysis of available controls to achieve reasonable progress towards the national visibility goal.

B. Units 821 and 822: Waukesha F3520GU 4-Stroke Rich-Burn RICE

Units 821 and 822 are Waukesha F3520GU 4-stroke rich-burn RICE constructed in 1967, each with a capacity of 418 hp.[728] The units each have an hourly NOx limit of 18.5 lb/hr and a combined annual NOx limit of 83.4 tpy.[729]

1. Use of Non-Selective Catalytic Reduction

The uncontrolled allowable NOx emission rates for units 821 and 822 of 18.5 lb/hr are equivalent to 20.1 g/hp-hr for these 418 hp engines. NPCA's March 2020 Oil and Gas Four-Factor Report provides an analysis of the cost effectiveness of NSCR to reduce NOx emissions from rich-burn RICE by 94%.[730] This cost analysis is laid out below, as applied to these two specific units at the Corona Compressor Station.

EPA describes NSCR and potential controlled emission rates in its Alternative Control Techniques document for RICE:

> Catalyst vendors quote NOx emission reduction efficiencies of 90 to 98 percent. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 0.3 to 1.6 g/hp-hr….[731,732]

[726] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[727] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[728] *Id.* at A5.
[729] *Id*. at A7.
[730] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 17-20 and Table 7 at 26.
[731] EPA 1993 Alternative Control Techniques Document for RICE at 2-10 to 2-11.
[732] Note, employing NSCR to reduce NOx emissions from EPA's uncontrolled emission rate of 15.8 g/bhp-hr to 1.0 g/bhp-hr corresponds to a NOx emission reduction efficiency of 94%. This control efficiency is used in the analysis presented here as a reasonable achievable emission rate but certainly not the lowest possibility.

A cost effectiveness analysis of NSCR was performed in 2010 for EPA, to help determine national impacts associated with EPA's final rule for Reciprocating Internal Combustion Engine National Emission Standards for Hazardous Air Pollutants (RICE NESHAP).[733] The analysis, performed by E^{C}/R Incorporated, was based on 2009 cost data for retrofitting NSCR on existing 4SRB engines from industry groups, vendors, and manufacturers of RICE control technology. E^{C}/R Incorporated performed a linear regression analysis[734] on the data set to determine the following linear equation for annual cost, which includes annual operating and maintenance costs plus annualized capital costs based on a 7% interest rate and 10-year life of controls:

NSCR Annual Cost = \$4.77 x (hp) + \$5,697 (2009\$)

The capital cost equation for retrofitting an air-to-fuel ratio controller (AFRC) and NSCR on a 4SRB engine was determined by E^{C}/R Incorporated to be, as follows:

NSCR Capital Cost = \$24.9 x (hp) + \$13,118 (2009\$)

These relationships are derived from a data set that includes engines ranging in size from 50–3,000 hp.

The E^{C}/R document does not explain why it assumed a 10-year life of controls for estimating the annualized capital costs. The life of a RICE unit is generally much longer than ten years, and is often at least thirty years.[735] The assumed 10-year life was not based on the catalyst replacement timeframe, because the E^{C}/R operating costs took into account the cost for replacing the catalyst every three years, as well as replacing the thermocouple every 7.5 years, the crankcase filters every three months, the oxygen sensor on a quarterly basis, and rotating the catalyst for cleaning annually.[736] Thus, the assumed 10-year life of an NSCR system seems arbitrary. In cost analyses done in 2000 for EPA, an equipment life of NSCR of fifteen years was assumed.[737] The state of Colorado also recently assumed a 15-year life of NSCR for RICE

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[733] Memo from E^{C}/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010), *available at*: https://www.epa.gov/sites/production/files/2014-02/documents/5_2011_ctrlcostmemo_exist_si.pdf.

[734] *Id.* The report notes that the linear equation has a correlation coefficient (R) of 0.7987, concluding that it "shows an acceptable representation of cost data."

[735] *See, e.g.*, EPRI, 20 Power Companies Examine the Role of Reciprocating Internal Combustion Engines for the Grid, *available at*: https://eprijournal.com/start-your-engines/. The authors also note that, in reviewing permits for gas processing facilities and compressor stations in New Mexico, it is not uncommon to have engines that were constructed from the 1950's to 1970's still operating at such facilities.

[736] Memo from E^{C}/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010), at 4 and at 11, 13, and 15.

[737] *See* August 11, 2000, E.H. Pechan & Associates, Inc., NOx Emissions Control Costs for Stationary Reciprocating Internal Combustion Engines in the NOx SIP Call States, at 5 and at A-2, *available at*: https://www3.epa.gov/ttn/ecas/regdata/cost/pechan8-11.pdf. *See also* EPA, Regulatory Impact Analysis for the NOx SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).

units.[738] Given that EPA assumed a selective catalytic reduction (SCR) system at an industrial fossil fuel-fired boiler has a life of 20-25 years,[739] it seems very likely that NSCR would have a useful life of at least fifteen years if not longer. For the purpose of the NSCR cost analyses presented here, a 15-year life of the NSCR system was assumed.

In addition, a lower interest rate than 7% is assumed in determining annualized costs of controls for this report. As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

The table below shows the cost effectiveness of NSCR and an AFRC achieving 94% NOx reduction efficiency and operating at 2,000 hours per year and 8,000 hours per year, based on these cost equations from EPA's 2010 RICE NESHAP, adjusted to reflect a 4.7% interest rate and 15-year life of controls.

Note that lower NOx emission limits may be possible that reflect a higher NOx removal efficiency than the 94% assumed in the table below and the costs of employing NSCR to meet these lower limits will be even more cost effective than what is shown here.

Table 53. Cost Effectiveness to Reduce NOx Emissions from 4SRB RICE with NSCR and an AFRC, Based on EPA RICE NESHAP Cost Equations for Existing Stationary RICE[740]

UNIT	SIZE, hp	ANNUALIZED COSTS OF NSCR AND AFRC, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2009$
801	418	$6,544	$499/ton	$125/ton
802	418	$6,544	$499/ton	$125/ton

We did not escalate these costs to 2019 dollars. The Chemical Engineering Plant Cost Index (CEPCI) has been used extensively by EPA for escalating costs, but EPA states that using the CEPCI indices to escalate costs over a period longer than five years can lead to inaccuracies in

[738] *See* Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for RICE Source Category, circa 2008 [hereinafter referred to as "CDPHE RP for RICE"], at 8, *available at*: https://www.colorado.gov/pacific/sites/default/files/AP_PO_Reciprocating-Internal-Combustion-Engine-RICE-engines_0.pdf.

[739] *See* EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 80, *available at*: https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.

[740] *See* Memo from E^C/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010). Annualized costs of control were calculated using a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 4.7% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and a 94% NOx removal efficiency.

price estimation.[741] Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. As an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. However, even today's costs for NSCR are assumed to be very cost effective given that the cost effectiveness based on 2009$ is on the order of $100/ton.

XXII. Durango Midstream - Empire Abo Gas Plant

The Empire Abo Gas Plant is a natural gas processing and gas sweetening plan located in Eddy County, New Mexico, operated by Durango Midstream. NMED did not request a four-factor analysis for this facility, but the source does have a Q/d value of 24.2 based on 2014 emissions and it is 68.9 kilometers from Carlsbad Caverns National Park according to NMED's Emission Data Analysis Tool. The plant is permitted to operate under two operating scenarios: 1) a gas sweetening and processing plant, and 2) a compressor station that receives gas at low pressure and routes it to the Maljamar Gas Plant for processing.[742] A review of data on NMED's Emissions Analysis Tool shows that the plant has varying emissions, with the last three years (2017-2019) being much lower emissions than in the past. For the 2016 year that most facilities used as a baseline, the plant emitted 271.1 tons of SO2. However, currently, the plant emitted 72 tons in 2019 and only 19 tons of SO2. In the 2012 to 2015 timeframe, the plant had about 200 tpy of NOx emissions and approximately 450-850 tpy of SO2 emissions. The state should request information from Durango Midstream as to the planned operation of the plant (whether it will be primarily as a gas sweetening plant or a compressor station) in 2028 to determine which sources to focus on for control.

Of all of the emission limits identified in the Title V permit, the SRU/Incinerator is allowed the highest level of emissions of 565 tpy.[743] Based on the discussion in Section XXIII below, NMED should thus require the company to evaluate an AGI well and/or an acid gas scrubber to add after the tail gas incinerator to remove SO2 when the SRU is down for maintenance.

XXIII. Comments on Pollution Control Evaluations for Amine Units/Acid Gas Flares at Gas Sweetening Plants

NMED requested four-factor analyses of controls for several amine units at New Mexico gas processing plants. Amine treating units are used to remove hydrogen sulfide (H2S) and carbon dioxide (CO2) from natural gas. Plants that remove H2S are referred to as gas sweetening plants. Amines such as Monoethanolamine (MEA), Diglycolamine (DGA), Diethanolamine (DEA) and Methyldiethanolamine (MDEA) can form salts with H2S and CO2 in an aqueous solution.

Targa's four-factor submittal for the Saunders gas plant describes and amine unit as follows:

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[741] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.
[742] 6/30/2017 Title V Permit No. P146-R3 for Empire Abo Gas Plant.
[743] *Id.* at A11.

> An amine treating unit operates by feeding the inlet gas stream into the bottom of a contactor and simultaneously feeding a lean amine solution at the top of the contactor. The two streams interact in counter flow, resulting in CO2 and H2S being stripped from the natural gas stream. The lean amine solution must be kept at a higher temperature than the gas feeding into the contactor, or condensation of heavier hydrocarbons could occur. Trays or packing in the contactor provide a place for the lean amine solution to interact with the inlet gas stream. The natural gas leaving the contactor will be "sweet gas."
>
> The rich amine leaving the contactor is usually sent to a flash tank which reduces the pressure of the stream and causes dissolved hydrocarbons to flash off. The rich amine will then pass through a heat exchanger and enter a solvent regenerator. The heated vapor generated at the bottom of the regenerator flows upward through the trays or packing where it comes in contact with the rich amine and removes the acid gases from the amine. The lean amine is then cooled and reenters the first contactor to start the process over. The acid gas that is dissolved in the vapor is then sent to a control device such as a sulfur recover unit (SRU) with a tail gas incinerator, a flare, or an acid gas injection (AGI) well.

November 2019 Four-Factor Analysis for Saunders Gas Plant at 2-8 to 2-9.

The acid gas exiting the amine unit is essentially composed of H2S and CO2. While the percentage of H2S and CO2 can vary depending on the sulfur content of the natural gas, as one example, a gas amine unit in Texas in the Permian Basin is composed of approximately 45% H2H and 54% CO2.[744] According to EPA's AP-42 Emission Factor documentation, emissions from gas sweetening units only result when gas is flared or incinerated and the major pollutant of concern from such flaring or incineration is SO2.[745] When the acid gas stream is flared rather than injected into the geologic strata or controlled with an SRU, all or most of the H2S is converted to SO2. While flaring may be a control for H2S in the acid gas stream, it is a cause of SO2 emissions and does not control SO2.

The typical controls for amine units are acid gas injection (AGI) well or a sulfur recovery unit (SRU). An AGI well should result in no emissions because the acid gas stream is injected into the geologic strata. However, if there are any malfunctions in the equipment that pumps the acid gas stream into the AGI, then air emissions can result. An SRU converts hydrogen sulfide to element sulfur. The most commonly applied method is the Claus method, which can typically recover 95-97% of the hydrogen sulfide feed stream.[746] According to EPA, older SRUs or very

[744] *See* Oil and Gas Docket No. 08-0289658, Application of James Lake Midstream, LLC, available for download at https://www.rrc.state.tx.us/hearings/dockets/oil-gas-proposals-for-decision-and-orders/index-for-336/.
[745] EPA, AP-42, Section 5.3 Natural Gas Processing at 5.3-3.
[746] EPA, AP-42, Sulfur Recovery at 8.13-1.

small Claus plants producing less than 22 tons of sulfur per day have varying sulfur recovery efficiencies.[747] The following table lists those amine units for which NMED requested four-factor analyses for the control of SO2.

Table 54. List of Facility Amine Units (or Acid Gas Flares) For Which NMED Requested Four-Factor Analysis of Controls and Potential to Emit (PTE) SO2 as Reported in Company Analysis

Facility	Amine Unit	Existing Controls	PTE SO2 tpy	PTE SO2 lb/hr
Jal No. 3	Unit 9S (Thermal Oxidizer)	SRU and AGI well	1,205.9	275.3
DCP-Eunice Gas Plant	Unit 31	SRU	257.2	9,368.2
Targa-Eunice Gas Plant	Unit AM-01/F-01	AGI well	776.5	5,176.6
Targa-Monument Gas Plant	Unit AM-01/F-03	AGI well	872.6	5,817.5
Targa – Saunders Gas Plant	Unit A-01/I-01	SRU with tail gas incinerator	1,397.0	316.7
DCP-Artesia Gas Plant	Amine-C Unit 23 (Acid Gas Flare)	AGI well	328.2	4918.4
Davis Gas Processing - Denton Gas Plant	Unit 005 (amine regeneration still and reboiler) and Unit 007 (acid gas flare)	None	1,195.9	312.5
Oxy-Indian Basin Gas Plant	Unit AMINE -1 & SELEXOL	AGI	Not indicated	Not Indicated

It must be noted that there are facilities listed in the above table that did not specifically list amine units but that otherwise did list startup, shutdown, and maintenance (SSM) emissions as triggering the need for a four-factor analysis due to SO2 emissions. For those facilities listed in the above table (DCP Eunice Gas Plant and DCP Artesia Gas Plant), the units have gas sweetening plants and the SO2 emissions from SSM are from flaring of the acid gases. Yet, those companies' four-factor analyses claimed they did not need to evaluate controls for SSM emissions that occur during "non-steady state" operations.[748] Flaring of the acid gas stream at units with amine units appear to, unfortunately, be part of the normal operations of the unit even though due to SSM, and there are control options available to reduce SO2 emissions from flaring – by reducing flaring via redundant acid gas steam control options (second AGI well, or

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[747] *Id.* at 8.13-3.

[748] *See*, e.g., November 2019 Four-Factor Analysis for DCP Eunice Gas Plant at 1-2 and November 2019 Four-Factor Analysis for DCP Artesia Gas Plant at 1-2.

redundant compressor at AGI well, or SRU plus AGI well) or by replacing a flare with an incinerator and acid gas scrubber to be used when the primary acid gas control for the amine unit is not functioning. Thus, NMED must not allow facilities with significant SO2 emissions due to SSM to be exempt from a four-factor analysis of controls.

The following provides a discussion of controls for SO2 emissions at gas sweetening plants in the context of reviewing and commenting on the four-factor submittals for the facilities listed in the above table.

A. Amine Units with No Acid Gas Controls – Denton Gas Plant

There is one amine unit listed in the above table which apparently has no H2S controls – the Davis Gas Processing Denton Gas Plant. Although the Denton Gas Plant used 2017-2018 SO2 emissions as baseline emissions for its cost effectiveness analysis, the plant's two-year average SO2 emissions have varied from 713.00 tpy (2017-2018 average) to 1,061.27 tpy over the past ten years.[749] Davis Gas Processing states that the sulfur recovery process (both the Claus process and another processed called LO-CAT) were eliminated from further consideration because of concerns of the level of control achievable with variable flowrates and H2S concentrations, which the company claims are common at Denton, and apparently because of the low throughput rate that would apply to an SRU at the Denton amine unit.[750] While a properly designed, operated, and maintained acid gas injection well would achieve a higher level of SO2 control (SO2 removal efficiency should be 100% with an AGI well), we note that NMED has requested some companies to analyze installing an AGI well in addition to having a sulfur recovery unit.[751] Such duplicative controls should be considered, even for units with AGI wells. Although an AGI well in theory should provide 100% control of SO2, problems with the equipment to compress and pump the acid gas steam into the AGI well can occur – or sometimes even with the AGI well. For example, Targa explained that its Monument AGI well "failed an OCD required pressure test on July 27, 2016" and the well had to be shut down August 8th and ultimately was abandoned, resulting in significant flaring of acid gas until the new well became operational in March 2017.[752] This flaring resulted in approximately 2,000 tons of SO2[753] from a pollution control that should have 100% SO2 reduction efficiency. While this AGI well malfunction may have been unique, there clearly are also problems with AGI compressors because other New Mexico companies have installed, or are in the process of installing, redundant compressors.[754] Yet, redundant compressors are not necessarily enough to prevent significant SO2 emissions from flaring that may occur during upsets or maintenance. NMED should ask each company with gas sweetening plants, including the Denton Gas Plant, to evaluate the cost of redundant SO2 pollution controls. One option is to install an SRU if the

[749] November 2019 Denton Gas Plant Four-Factor Analysis at 2-2.
[750] *Id.* at 2-4.
[751] *See* Targa's February 2020 Four-Factor Addendum for the Eunice Gas Plant at pdf page 10.
[752] *Id.*at pdf page 9.
[753] *Id.*
[754] *Id.* at pdf page 10. Targa states that it installed redundant compression at the Monument AGI well as a result of an AQB enforcement case. Targa also installed redundant compression at the Eunice Gas Processing Plant.

facility already has an AGI well, to be used when the AGI well cannot be used for control. Another option is to have the gas routed to an incinerator with an add-on acid gas scrubber, when the AGI well is not functioning.[755] For those facilities that have SRUs to control SO2 from amine units or that have no SO2 controls such as the Denton Gas Plant, adding an AGI well as a duplicative control should be evaluated first.

The four-factor analysis for the Denton Gas Plant evaluated the costs of installing an AGI well. While the Denton analysis used a 5.25% interest rate and a 20-year life as well as the lowest 2-year baseline of all of the past 10 years of SO2 emissions, the company's cost effectiveness analysis shows that an AGI well would be quite cost effective at $1,014/ton of SO2 removed.[756] Davis Gas Processing likely overstated the capital costs of an AGI well, by adding 25% to the purchased equipment costs as well as using EPA's Control Cost Manual's percentage of purchased equipment costs for foundations and supports, handling and erection, etc.[757] As the company notes in its four-factor analysis, the use of AGI for the disposal of acid gas "is becoming increasingly common…"[758] Thus, rather than adding a 25% contingency factor to the purchased equipment cost and then adding EPA's Control Cost Manual estimates (which are a percentage of the purchased equipment costs) for installation of an AGI, the company could have obtained a reliable estimate of the cost of AGI well installation. With respect to operating expenses, David Gas Processing's analysis assumed a cost per kW hour of $0.11 which appears to be the cost for residential service in New Mexico.[759] The electricity cost for an industrial user is generally much lower than a residential user. EPA estimates the cost for electricity in its SCR cost spreadsheet of $0.0676/kWh. A web search for average electricity cost in New Mexico for industrial use shows a cost of $0.0583/kWh.[760] Thus, annual electricity costs for the electric compressors for an AGI well in New Mexico should be in the range of $41,893 to $48,575 rather than the $79,043 assumed for the Denton Gas Plant. Further, this cost reflects electricity use when the compressors are used at maximum capacity for all hours of the year, so this is a worst case annual operating cost. The company's assumed cost for electricity has a significant impact on the cost effectiveness of an AGI well. When just the cost for electricity is revised to be $0.0583/kWh, the cost effectiveness of an AGI well at the Denton Gas Plant reduced from $1,014/ton to $663/ton. If the interest rate is lowered to a more reasonable 4.7% for the reasons discussed in this report and the life of an AGI well is increased to 25 years which seems reasonable given the life of gas sweetening plants like Denton, the cost effectiveness of an AGI well further reduces to $574/ton. Moreover, if one removes the 25% contingency factor that Davis Gas Processing applied to its estimate of equipment costs, the cost effectiveness of AGI to reduce SO2 would be $481/ton. Clearly, installation of an AGI well is very cost effective for the Denton Gas Plant.

[755] *See* March 2020 NPCA Oil and Gas Four-Factor Report at 148-154.
[756] November 2019 Denton Gas Plant Four-Factor Analysis at 3-4.
[757] *Id.*
[758] *Id.* at 2-5.
[759] *See*, e.g., https://www.electricitylocal.com/states/new-mexico/.
[760] https://www.electricitylocal.com/states/new-mexico/

B. Amine Units with SRUs – DCP Eunice Gas Plant and Targa Saunders Gas Plant

With respect to the DCP Eunice Gas Plant which has an SRU, DCP's four-factor analysis claims that the area is not suitable for an AGI well[761] despite being near to the Targa Monument Gas Plant which also has an AGI well. It appears that the plants are roughly 10 miles apart. NMED should request more information from DCP as to why it claims an AGI well is not viable for its Eunice Gas Plant. Not only could this provide more information to enable NMED to thoroughly consider the Targa Monument Plant's SO2 controls for its amine plant, but it is needed to justify DCP's claims that an AGI well is not feasible for its location especially given how cost effective an AGI well can be based on the revised Denton Gas Plant analysis discussed above. DCP states that AGI wells typically include a second redundant AGI well.[762] The fact that such redundancy is required for SO2 controls when an AGI well is used for control argues for redundancy in controls when an SRU (which is not nearly as efficient in SO2 reduction as a properly operating AGI well) is used for SO2 control. Use of an incinerator with an add-on acid gas scrubber as a redundant control for those amine units with SRUs should thus be evaluated as an additional SO2 control. This could be used downstream of the SRU to improve SO2 removal efficiency when the SRU is operating and could also be used when the SRU is down for maintenance or upsets. These types of duplicative control have been used in oil refineries and thus are a viable control option for a natural gas processing plant as well.[763] NMED should thus require DCP to evaluate this control option. In addition, NMED should ask DCP to report on its SO2 removal efficiency of its current SRU and to quantify its actual SO2 emissions from flaring the acid gas stream when the SRU is down for maintenance or upsets. As part of its four-factor analysis, NMED must evaluate the level of SO2 control currently being achieved at the gas sweetening plant and ensure that all available options for improving that level of control are evaluated. The Targa Saunders Gas Plant utilizes a "Select-Tox Single State Claus bed with a tail gas incinerator" as a control for the amine unit, with an acid gas flare when the SRU is down for maintenance.[764] Targa considered an AGI well, but claimed it could not install an AGI well without plugging/cementing some of the numerous other wells in the area because acid gas could vent from any unplugged wells.[765] NMED should request more information on the documentation collected by Targa to support this claim. Targa did not evaluate any other controls to reduce SO2 emissions from its amine unit after finding an AGI well was not feasible for the Saunders plant.[766] NMED should require Targa to evaluate the option of adding an acid gas scrubber to its tail gas incinerator and to operate the incinerator and scrubber when the SRU is not available due to maintenance or upsets. This would enable the continued control of SO2 even during SRU downtime, rather than flaring which does not control SO2 emissions at all. In addition, NMED should ask DCP to report on its SO2 removal efficiency of its current SRU and

[761] November 2019 Four-Factor Analysis for DCP Operating Company's Eunice Gas Plant at 2-8 to 2-9.
[762] *Id.*
[763] *See*, e.g., July 2006, Meyer, Steven F., Christina Kulczycki, Ed Juno, and Nick Watts, Improving Sulphur recovery units, Digited Refining, available at https://www.digitalrefining.com/article/1000244/improving-sulphur-recovery-units#.XvJCRudME2w.
[764] November 2019 Four-Factor Analysis for Targa Saunders Gas Plant at 2-9.
[765] *Id.* at 2-10.
[766] *Id.* at 3-3.

to quantify its actual SO2 emissions from flaring the acid gas stream when the SRU is down for maintenance or upsets. As part of its four-factor analysis, DCP must evaluate the level of SO2 control currently being achieved at the gas sweetening plant and ensure that all available options for improving that level of control are evaluated.

C. Amine Units with AGI Wells – Targa Eunice Gas Plant, Targa Monument Gas Plant, DCP Artesia Gas Plant, and Oxy Indian Basin Gas Plant

As indicated above, the Targa Monument Gas Plant flared its acid gas stream for several months in 2016 -2017 due to a failed AGI well after five years of service.[767] This facility provides a pertinent example of how - even an amine unit controlled by an AGI well, which should theoretically eliminate 100% of the potential SO2 emissions - acid gas injection wells need backup and/or redundancy to ensure control of SO2. Indeed, NMED must require all amine plants with AGI wells in the table above to consider duplicative controls for removal of sulfur from the acid gas stream or prevention of SO2 emissions from flaring. Options to consider are 1) a duplicative AGI well, 2) an incinerator and add-on acid gas scrubber or an SRU for when the acid gas stream cannot be routed to the AGI well, and 3) duplicative equipment for ensuring the acid gas is continually injected into the acid gas well, such as a redundant electric compressor. The four-factor analysis submitted by Targa for the Eunice Gas Plant claims the AGI well is in the process of having redundant electric compression added to the AGI well to further reduce SO2 emissions during SSM.[768] Targa did not evaluate any other controls. Similarly, Targa stated that it is adding redundant electric compression to the Monument AGI well, and the company did not evaluate any other controls for its amine plant.[769] While having redundant compression will help to ensure that the acid gas stream is not flared due to the AGI well compressor malfunctioning or being down for maintenance, NMED should ask Targa to evaluate the costs of adding an SRU or adding an incinerator and acid gas scrubber for further redundancy in its SO2 control systems. With respect to the Monument Gas Plant AGI well, given the statements made by DCP in its four-factor analysis for the Eunice Gas Plant that the area is not well-suited for acid gas injection and given the Monument plant's proximity to the DCP Eunice Gas Plant, NMED must determine if the failure of the Monument AGI well is due to any of the reasons that DCP indicated in its Eunice Gas Plant four-factor analysis for an AGI well not being viable in the region. Further, NMED should collect and present data on the last five years of how much SO2 was emitted due to flaring of the acid gas stream at Monument due to upsets at the AGI well's compressors or other causes of flaring of the acid gas stream. Given the failure of the Monument AGI well after five years and the resulting 2,000 tons of SO2 emitted, it seems that redundant controls such as an SRU or an incinerator with acid gas scrubber must be considered as a duplicative SO2 control for the amine unit at the Monument Gas Plant. NMED should also require an evaluation of such controls for the Targa Eunice Gas Plant.

[767] *See* Targa's February 2020 Four-Factor Addendum for the Eunice Gas Plant at pdf page 9.
[768] November 2019 Four-Factor Submittal for Targa Eunice Gas Plant at 2-6.
[769] November 2019 Four-Factor Submittal for Targa Monument Gas Plant at 2-1.

In the Oxy Indian Basin Gas Plant four-factor submittal, Oxy only evaluated one control – a redundant compressor for the AGI.[770] Oxy's submittal indicated a cost effectiveness of $27,600/ton of SO2 reduced due to an estimated cost for electric compression of $11 million.[771] The company assumed baseline emissions from 2016 of NMED of 41.92 tpy and assumed a redundant compressor would reduce those emissions by 90%. NMED should ensure that the company is using realistic baseline emissions due to flaring of the acid gas stream. If 2016 was an exceptionally good year (not much flaring), but prior years had much higher emissions, cost effectiveness should be based on a longer term average of emissions. If baseline emissions were 200 tpy of SO2 from flaring, and with a more appropriate interest rate and lifetime of electric compressor of 4.7% and 25 years (instead of 5.50% and 20 years), the cost effectiveness of a redundant compressor would reduce to $4,873/ton. If the plant emitted 500 tpy, the cost effectiveness would be about $2,000/ton. Thus, it is imperative that NMED ensure that the company uses a realistic SO2 baseline for evaluating redundant controls such as duplicative compressor for its acid gas injection well. NMED did ask Oxy to consider adding a second control to its AGI system to reduce flaring emissions, such as the LO-CAT sulfur recovery technology.[772] The company indicates that it had an SRU that has been shut down due to poor reliability.[773] Given that the SRU already exists on site, NMED should ask the company to evaluate the cost for bringing the SRU back online to use only as a backup to the AGI well. That could be a very cost effective way to ensure redundancy in the SO2 removal systems at the Indian Basin Gas Plant.

DCP did not evaluate any controls for its amine plant at the Artesia Gas Plant. The company's four-factor analysis only listed emissions from flaring and stated that, based on NMED's September 23, 2019 guidance, it did not need to evaluate controls from flaring.[774] Yet, it listed acid gas flaring (Unit 23) as a significant source of SO2 emissions.[775] A review of the Title V permit for the facility shows that the facility has an amine plant and an AGI well.[776] NMED must request that the company provide information on its actual SO2 emissions from flaring the acid gas stream from its amine unit. Further, NMED must request DCP to evaluate duplicative controls and/or redundant AGI well compression.

Moreover, as part of evaluating SO2 control options for any gas processing plant, NMED should collect information on the time periods, causes, and SO2 emissions of acid gas stream flaring at the plant to determine if additional maintenance requirements should be imposed with reporting and recordkeeping to NMED.

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[770] November 2019 Four-Factor Analysis for Indian Basin Gas Plant at 2-5, 3-2, and Appendix B.
[771] *Id.* at Appendix B.
[772] February 2020 Four-Factor Addendum for Oxy Indian Basin Gas Plant at pdf page 2.
[773] *Id.*
[774] November 2019 Four-Factor Submittal for DCP Artesia Gas Plant at 1-2.
[775] *Id.*
[776] 6/27/17 Title V Permit No. P095-R3 for DCP Artesia Gas Plant at A8.

D. Units with SRU and AGI Well – Jal No. 3

The four-factor analysis for the Jal No. 3 amine plant states that the acid gas from its amine units is sent to a sulfur recovery unit which scrubs the H2S at 92% efficiency and that the leftover H2S from the SRU is sent to the thermal oxidizer to be combusted.[777] During downtime of the SRU and/or thermal oxidizer, the acid gas is sent to the AGI wells, and during AGI well downtime, the acid gas is sent to the SRU and thermal oxidizer.[778] The company's four-factor analysis states that "[t]hese existing controls are the best known technologies for controlling acid gas and, to our knowledge, there are no other technically feasible control options to further reduce SO2 emissions from the thermal oxidizer."[779] While this suite of controls does reflect the type of duplicity in controls that is necessary for addressing SO2 emissions as gas sweetening plants, it does seem that there are additional control options that the company should have considered. Despite these duplicative controls, the facility emits significant quantities of SO2. According to date on NMED's Emissions Analysis Tool, the Jal No. 3 plant emitted almost 2,000 tons of SO2 in 2016, the year NMED is apparently using as the baseline year for company four-factor analyses. While SO2 emissions have decreased since then, annual SO2 emissions have varied from 207 tons in 2017 to 1,444 tons in 2018 to 587 tons in 2019. Presumably these emissions are all from the Unit 9S thermal oxidizer, as that appears to be the primary source of SO2 emissions based on a review of the Title V permit.

Two additional control options should have been considered for the Jal No. 3 amine unit/thermal oxidizer: 1) Routing the cleaned acid gas stream from the SRU to the AGI well during normal operation of the SRU, which would improve SO2 removal efficiency from 92% to 100% (when the AGI well was operating and not down for maintenance or upset). Under this control option, the plant should continue to route the acid gas stream directly to the AGI wells during SRU downtime; or 2) Revise the configuration to inject the acid gas stream from the amine units to AGI wells, but route the acid gas stream to the SRU/thermal oxidizer during AGI well downtime to at least achieve 92% H2S removal before combusting the acid gas. It seems like either of these two options could provide for significant additional control of SO2 from the amine units at the Jal No. 3 gas plant. NMED must require ETC Texas Pipeline to evaluate these available control options at Jal No. 3 (given that the SRU and the AGI wells already exist at the facility) to control the SO2 emissions from the facility which can be quite significant despite the plant's duplicative controls.

E. Summary

In summary, because the flaring or incineration of acid gas streams from amine units at gas sweetening plants can be such a significant source of SO2, NMED must ensure a thorough evaluation of control options for such sources. NMED should not consider such sources of emissions to be non-steady state and exempt from the four-factor review of controls, because

[777] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at 7.
[778] *Id.*
[779] *Id.* at 8.

such emissions of SO2 can be very high and can be addressed through duplicative or redundant controls. NMED must also ensure that reasonable evaluations of baseline emissions are used in evaluating the cost effectiveness of controls, in that the baseline emissions must realistically depict emissions from acid gas incineration at a facility.