REGIONAL HAZE FOUR-FACTOR ANALYSIS

El Paso Natural Gas Company, L.L.C. - Willcox Compressor Station

Arizona Department of Environmental Quality

Prepared For:

El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

5151 E BROADWAY BLVD., SUITE 1680
TUCSON AZ 85711
(520) 663-4239

Prepared By:

TRINITY CONSULTANTS
1661 E Camelback Road, Suite 290
Phoenix, AZ 85016
(602) 274-2900

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1. EXECUTIVE SUMMARY

The U.S. Environmental Protection Agency (EPA) Regional Haze Rule (RHR) is designed to improve visibility at national Class I areas to natural levels by 2064. The program is designed to achieve this goal by assessing visibility during various "planning" periods, demonstrate that visibility improvements are progressing along the Uniform Rate of Progress (URP), and require controls to demonstrate reasonable progress. The current planning period requires that states submit updated implementation plans no later than July 31, 2021. The analysis requires the development of a "Source Screening" approach to remove sources from further consideration. Sources that are not screened out are subject to additional review such as a four-factor analysis (4FA).

The Arizona Department of Environmental Quality (ADEQ) informed the El Paso Natural Gas Company, L.L.C. (EPNG), a Kinder Morgan Company that the Willcox Compressor Station was selected for a 4FA. The ADEQ has also provided EPNG with a list of emission points that are subject to the 4FA. This report details the methodology used to complete the 4FA for these emission points and summarizes the associated results. Table 1-1 summarizes the results of the 4FA for the Willcox Compressor Station.

Table 1-1. Willcox Compressor Station – Four Factor Analysis Conclusions

Emission Unit Identifier	Pollutant	Proposed Control	Post Control Emission Rate (tpy)	Proposed Emission Rate Averaging Period
TURBINE-1	NO_x	Good Combustion Practices	N/A	N/A
TURBINE-2	NO_x	Good Combustion Practices	N/A	N/A

2. INTRODUCTION

In the 1977 amendments to the Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural visibility conditions by remedying existing anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the EPA published the final RHR located at Title 40 of the Code of Federal Regulations (40 CFR) §51.308. The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across the United States, known as Federal Class I areas. Pursuant to 40 CFR §51.308(d)(1), the RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal (RPG) for a Class I area, each state must:

- Pursuant to 40 CFR §51.308(d)(1)(i)(B), "*Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction.*" The URP or improvement is also known as the "glidepath".

- Pursuant to 40 CFR §51.308(d)(1)(i)(A), "*Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.*" This is known as a four-factor analysis (4FA).

The program is designed to assessing visibility at Class I areas during various "planning" periods. As part of the first planning period (for the period between 2004 and 2018) states were required to submit implementation plans (SIPs) no later than December 17, 2007. The second planning period (for the period between 2018 and 2028) requires that states submit updated SIPs no later than July 31, 2021 and is currently underway.

3. REGIONAL HAZE SECOND PLANNING PERIOD & EPNG

Pursuant to 40 CFR 51.308(d)(3)(iv), states are responsible for identifying the sources that contribute to the most impaired days (MID) in the Class I areas. To accomplish this, the ADEQ reviewed calendar year 2014 emission inventory data for sources of PM_{10}, NO_x, and SO_2, and developed a "source screening" approach using a "Q/d" analysis, to remove sources from further consideration. In this analysis "Q" is the aggregate tons per year of PM_{10}, NO_x, and SO_2, and "d" is the distance (km) of a facility to a Class I area. Arizona utilized guidance from the Western Regional Air Partnership (WRAP) regarding using a threshold of "Q/d > 10" to screen out sources from four-factor analysis. Additionally, the ADEQ evaluated calendar year 2018 facility operations and emissions to determine which processes have installed an "effective control" within the last five years. Those processes which have an "effective control" were deferred from further evaluation during this planning period.[1] Based on the results of the initial "Q/d > 10" and "effective control" screening approach, ADEQ identified that the EPNG Willcox Compressor Station is subject to the requirements to develop a 4FA. For facilities that are subject to the requirement to develop a 4FA, ADEQ determined that the 4FA must be completed for emission points at these facilities contributing to the top 80% of the "Q" emissions.

The Willcox Compressor Station is located in Cochise County, on Arzberger Road six miles east of Kansas Settlement Road. The nearest Class I area to the station is the Chiricahua Wilderness, located 27 km away from the station. ADEQ calculated the "Q/d" for this source to be 12. Table 3-1 provides a list of all equipment at the Willcox Compressor Station that is subject to the four-factor analysis as determined by the "Top 80% of Processes" provided by the ADEQ.[2] NO_x is the only pollutant subject to evaluation in this four-factor analysis.

Table 3-1. Emission Points Subject to Four-Factor Analysis

Equipment Type	Max Capacity	Make	Model	Serial Number	ADEQ Unit Description	Pollutant Subject to 4FA	Installation / Manufacturing date
Gas Turbine	10,110 hp	General Electric	M3142R-J	226335	TURBINE-1	NO_x	1977
Gas Turbine	10,110 hp	General Electric	M3142R-J	226001	TURBINE-2	NO_x	1972

[1] ADEQ 2021 Regional Haze State Implementation Plan Source Screening Methodology

[2] Per "Four Factor Processes" spreadsheet received September 2019.

4. FOUR-FACTOR ANALYSIS METHODOLOGY & RESULTS

The 4FA completed as part of this report contains the following four statutory factors:

1. Cost of the control;
2. Time necessary to install the control
3. Energy and non-air quality impacts of the control; and
4. The remaining useful life of the emission point.

Factors 1 and 3 of the four factors are considered by conducting a step-wise review of emission reduction options in a top-down fashion similar to the top-down approach that is included in the EPA RHR guidelines for conducting a review of Best Available Retrofit Technology (BART)[3]. These steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate energy and non-air quality impacts and document the results

Factor 4 is also addressed in the step-wise review of the emission reduction options, primarily in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by limited equipment life. Once the step-wise review of control options is completed, a review of the timing of the emission reductions is provided to satisfy Factor 2 of the four factors.

4.1. TURBINES – NO_X CONTROLS

This section presents the step-wise review of control options for NO_x for the GE gas turbines located at the Willcox Compressor Station.

4.1.1. Identification of Potential Control Technologies

NO_X reduction can be accomplished by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the kinetics of NO_X formation (reducing peak flame temperature) or introduce inerts (combustion products, for example) that limit initial NO_X formation, or both. Several post-combustion NO_X control technologies are potentially applicable to the GE gas turbines. These technologies employ various strategies to chemically reduce NO_X to elemental nitrogen (N_2) with or without the use of a catalyst.

In order to identify all feasible control technologies, the RACT/BACT/LAER Clearinghouse (RBLC) database as well as technical literature was reviewed. Using these sources, potentially applicable NO_X control technologies for turbines were identified based on the principles of control technology and engineering experience for general combustion units.

[3] Pursuant to EPA "Draft Guidance on Progress Tracking Metrics, Long-Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period", July 2016, "many of the statements in the BART Guidelines continue to be relevant as recommendations for how a state should assess facts related to the four statutory factors."

Step 2 of the top-down control review is to eliminate technically infeasible NO_x control options that were identified in the first step.

It should be noted that the turbines at the Willcox Compressor Station were built in the 1970’s. Original Equipment Manufacturer (OEM) technology relative to NO_x emissions abatement has evolved substantially over the last 50 years. Low NO_x combustion modifications are generally developed specific to a particular model by the OEM and are not offered for the turbines at the Willcox Compressor Station. As such, these technologies are not considered to be “reasonably available” for the turbines as discussed in more detail below.

Combustion control options include:

- Water or Steam Injection
- Combustion Liner Upgrade and Low NO_X Burner Design (e.g., Dry Low-NO_X (DLN) Combustion Technology)
- Good Combustion Practices (Base Case)

Post-combustion control options include:

- EM_X™/$SCONO_X$™ Technology (oxidation catalyst)
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)

Each control technology and its feasibility are described in detail below to satisfy Steps 1 and 2 of the top-down control review.

4.1.1.1. Water or Steam Injection

Water or steam injection operates by introducing water or steam into the flame area of the gas turbine combustor. The injected fluid provides a heat sink that absorbs some of the heat of combustion, thereby reducing the peak flame temperature and the formation of thermal NO_x. The water injected into the turbine must be of high purity such that no dissolved solids are injected into the turbine. Dissolved solids in the water may damage the turbine due to corrosion and/or the formation of deposits in the hot section of the turbine. The requirement of high-purity water can be expensive to retrofit because the Willcox Compressor Station currently does not have water treatment system on site. Moreover, the consumption of water can be very high for a large turbine. Such high water usage may pose problems for the local water supply and is an added expense. This is important especially in dry regions such as Arizona. Although water/steam injection acts to reduce NO_x emissions, the lower average temperature within the combustor may produce higher levels of CO and hydrocarbons because of incomplete combustion. Additionally, water/stream injection results in a decrease in combustion efficiency and increase in maintenance requirements due to wear on the turbine and combustor.

Both turbines at the Willcox Compressor Station are GE Frame 3 turbines. Per EPNG’s engineering team, the water or steam injection technology is not available to the GE Frame 3 gas turbines. This NO_x control method is not technically feasible.

4.1.1.2. Lean Head End Combustion Liner Upgrade

The liner of a turbine surrounds the combustion process and allows for various airflows to pass through into the combustion zone. The liner is subject to high temperatures due to the combustion process which it contains. Because of this, the life of the liner is limited. Replacing the old combustion liner with a new, upgraded liner is a common retrofit. Combustion liners have a limited lifespan and are designed to be replaced. This control is feasible.

4.1.1.3. Dry Low-NO_X (DLN) Combustors

Lean premix technology, also referred to as dry low-NO_x (DLN) combustion technology, is a pollution prevention technology that controls NO_X emissions. DLN inhibits the conversion of atmospheric nitrogen to NO_X in the turbine combustor. This is accomplished by reducing the combustor temperature using lean mixtures of air and/or fuel staging or by decreasing the residence time of the combustor through combustion chamber design. For existing turbines, the combustion chamber would need to be redesigned and reconfigured to allow for lean premixing or fuel staging.

In lean combustion systems, excess air is introduced into the combustion zone to produce a significantly leaner fuel/air mixture than is required for complete combustion. This excess air reduces the overall flame temperature because a portion of the energy released from the fuel must be used to heat the excess air to the reaction temperature. Pre-mixing the fuel and air prior to introduction into the combustion zone provides a uniform fuel/air mixture and prevents localized high temperature regions within the combustor area. The fuel to air ratio must be maintained within a relatively narrow range to obtain low NO_X without blowout and without increasing carbon monoxide (CO) emissions, which are generated during incomplete combustion.[4] Since NO_X formation rates are an exponential function of temperature, turbines having frequent and rapid load changes may experience a brief spike in NO_x emissions with DLN technology.

4.1.1.4. Lean Head End Combustion Liner Upgrade and Dry Low-NO_X (DLN) Combustors

Lean Head End Combustion liner upgrade and DLN combustors are analyzed together for the remainder of this report, as both retrofits could be accomplished simultaneously during a major overhaul of the turbines. The installation cost would be optimized by adding both of these controls at the same time. DLN control technology combined with a liner upgrade is an available option for the GE Frame 3 gas turbines. Note that the DLN combustion technology requires conversion of the GE gas turbine from regenerative cycle to simple cycle. The simple cycle conversion of the turbines will have adverse impacts on the efficiency of the gas turbines, increasing fuel usage up to 40%.

4.1.1.5. EM_X/$SCONO_X$

EM_X™ (the second-generation of the $SCONO_X$ NO_X Absorber Technology) utilizes a coated oxidation catalyst to remove both NO_X and CO without a reagent, such as NH_3. Hydrogen (H_2) is used as the basis for the proprietary catalyst regeneration process. The $SCONO_X$ system consists of a platinum-based catalyst coated with potassium carbonate to oxidize NO and CO. The NO_2 molecules are subsequently absorbed on the treated surface of the $SCONO_x$ catalyst. The catalyst is installed in the flue gas with a temperature range between 300°F to 700°F.[5]

The EM_X™/$SCONO_X$™ catalyst system is designed to operate effectively at temperatures ranging from 300 to 700 °F. The turbines at EPNG have exhaust temperature of approximately 800 °F.[6]

[4] "Retrofitability of DLN/DLE system," GE Technology Insights 2013.

[5] BACT Analysis for JEA-Greenland Energy Center Units 1 and 2, Combined Cycle Combustion Turbines. Prepared by Black & Veatch (September 2008).

[6] Per average of 2016, 2017, and 2018 emissions test summaries.

EM_X™/$SCONO_X$™ applications on turbines with outlet temperatures this high have not been identified. Consequently, it is concluded that EM_X™/$SCONO_X$™ is not technically feasible for control of NO_X emissions from the turbines.

4.1.1.6. Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is a post-combustion gas treatment process in which urea or ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, ammonia and nitric oxide (NO) react to form diatomic nitrogen and water vapor. The chemical reactions can be expressed as:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 \rightarrow 3\ N_2 + 6\ H_2O$$

When operated within the optimum temperature range, the reaction can result in removal efficiencies between 70 and 90 percent.[7] In order for the SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 and 850 °F), dependent on the material of the catalyst. SCR units have the ability to function effectively under fluctuating temperature conditions although fluctuation in exhaust gas temperature reduces removal efficiency slightly by disturbing the NH_3/NO_x molar ratio. SCR installations typically have an operating range of 450 to 850ºF. The exhaust temperatures of the turbines are approximately 800ºF, making this control technology feasible.

It should be noted that there are several operational issues which may inhibit the effectiveness of SCR as a control option for turbines at natural gas compressor stations. The NH_3/NO_x molar ratio of 1:1 must be carefully controlled to allow for optimum NO_x reduction while limiting the amount of nonreacted NH_3 emitted to the atmosphere (known as “ammonia slip”). This ratio is difficult to control in units which have the variable loads experienced at compressor stations. The unit loading and speed of the turbines fluctuate continually according to the time of day, changes in the weather, and customer demands. Throughout the day, units are started and stopped and loads are changed to keep pipeline operating pressures within safe operating parameters and keep volumes sufficient to meet customer obligations. Although the variable nature of compressor station turbine loads does not make SCR operation technically infeasible, the inherent lag between CEM sampling and ammonia injection for the turbines may cause hourly NO_x emission limits to be exceeded during periods of increasing load and nonreacted NH_3 emissions (“ammonia slip”) to increase during periods of load loss.

4.1.1.7. Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion NO_x control technology based on the reaction of urea or ammonia with NO_x. In the SNCR chemical reaction, urea [$CO(NH_2)_2$] or ammonia is injected into the combustion gas path to reduce the NO_x to nitrogen and water. The overall reaction schemes for both urea and ammonia systems can be expressed as follows:

$$CO(NH_2)_2 + 2\ NO + \tfrac{1}{2}\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$$
$$4\ NH_3 + 6NO \rightarrow 5\ N_2 + 6\ H_2O$$

[7] U.S. EPA, Office of Air Quality Planning and Standards. *OAQPS Control Cost Manual Section 4-2 Chapter 2*,updated on June 12, 2019.

Typical removal efficiencies for SNCR range from 40 to 60 percent.[8] An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600 to 2,000°F.[9] Operation at temperatures below this range results in ammonia slip (when non-reacted NH_3 emitted to the atmosphere). The temperature range required for effective operation of this technology is above the peak exhaust temperature for the GE gas turbines assessed here. For this reason, it has been determined that this control technology is not feasible for the GE gas turbines at Willcox Compressor Station.

4.1.1.8. Good Combustion Practices (base case)

NO_x emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the combustion chamber where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_x emissions.

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC for the control of NO_x emissions from combustion turbines; therefore, it has been determined that this method of NO_x control is feasible for the GE gas turbines at Willcox Compressor Station. EPNG has developed Turbine Inspection and Maintenance Schedules Best Practices procedures, which are based on manufacturer recommendation, and EPNG has systems in place to ensure that its turbines are operated and maintained in accordance with these procedures. These practices are currently in use at Willcox Compressor Station. No further assessment of these control practices is included in this report.

4.1.2. Rank of Remaining Control Technologies Based on Control Effectiveness

The three potentially feasible control technologies are a combustion liner upgrade with DLN, SCR, and good combustion practices. The control efficiency associated with each control is summarized in Table 4-1.

Table 4-1. Potential Feasible NO_X Control Technologies

Rank	Control Technology	Potential Control Efficiency (%)	
		TURBINE-1	TURBINE-2
1	SCR	70	70
2	Liner Upgrade and DLN	69	70
3	Good Combustion Practices	Base Case, already in use	

[8] U.S. EPA, Office of Air Quality Planning and Standards. *OAQPS Control Cost Manual Section 4-2 Chapter 1*, updated on April 25, 2019.

[9] U.S. EPA, Clean Air Technology Center. *Oxides of nitrogen (NO_X), Why and How They Are Controlled*. Research Triangle Park, North Carolina. p. 18, EPA-456/F-99-006R, November 1999.

4.1.3. Evaluation of Impacts for Potentially Feasible Control Technologies

The fourth step of the top-down control review is the impact analysis. The impact analysis considers the:

- Cost of control;
- Time necessary to install the control;
- Energy impacts and non-air quality impacts; and
- The remaining useful life of the GE turbines.

The cost of each control technology was estimated using published methods,[10,11] vendor quotes, and turbine characteristics. The initial capital cost was annualized over a 15-year period and added to the annual operating costs.

The remaining useful life of each turbine is estimated to be 15 years (after 2028, which is the earliest time that the controls are expected to be installed) for either control. The choice of control technology does not affect the remaining useful life of the GE gas turbines. Cost effectiveness for each potential control technology is discussed below.

Detailed calculations for the turbines can be found in Appendix A.

4.1.3.1. SCR

Cost of Control Technology: The total annualized cost for TURBINE-1 was estimated to be $910,693 to remove 112 tpy of NO_x. This equates to a cost effectiveness of $8,130 per ton of NO_x removed. The projected 2028 cost is $10,163 per ton of NO_x removed. The post-control emission rate was estimated at 294 lb NO_x/MMCF.

The total annualized cost for TURBINE-2 was estimated to be $959,262 to remove 122 tpy of NO_X. This equates to a cost effectiveness of $7,895 per ton of NO_x removed. The projected 2028 cost is $9,868 per ton of NO_x removed. The post-control emission rate was estimated at 290 lb NO_x/MMCF.

Time necessary to install controls: A total of 14 months for each turbine is the estimated time to install SCR system. This estimation is from vendor quotes and includes time for engineering, permitting, and installation.

Energy and non-air quality impacts: Selective catalytic reduction requires an ammonia storage, handling and delivery system. This includes vaporizers and blowers to prepare the ammonia reagent for injection. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Storage, transportation, and handling of ammonia increases risk of human exposure. In addition to risks with ammonia, spent catalyst is classified as a hazardous waste. Turbine efficiency would also be affected because an SCR system increases the engine backpressure.[12]

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[10] U.S. EPA, Office of Air Quality Planning and Standards. *OAQPS Control Cost Manual,* 7th edition. EPA 452/B-02-001. Research Triangle Park, NC. June 2019.

[11] EPA "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" dated August 20, 2019

[12] Per EPA document "*Alternative Control Techniques Document -- NO_x Emissions from Stationary Reciprocating Internal Combustion Engines", July 1993.*

In addition, it should be noted that in order to construct an SCR system, the building that houses the turbines may have to undergo drastic modifications to accommodate the system. Although this was not included in the cost analysis, the cost to modify the current building design could surpass millions of dollars.

4.1.3.2. Lean Head End Combustion Liner Upgrade and Dry Low NO_X Combustion

Cost of Control Technology: The total annualized cost for TURBINE-1 was estimated at $1.05 million to remove 93 tpy of NO_x. This equates to a cost effectiveness of $11,272 per ton of NO_x removed. The projected 2028 cost is $14,090 per ton of NO_x removed. The post-control emission rate was estimated at 298 lb NO_x/MMCF.

The total annualized cost for TURBINE-2 was estimated at $1.13 million to remove 110 tpy of NO_x. This equates to a cost effectiveness of $10,300 per ton of NO_x removed. The projected 2028 cost is $12,876 per ton of NO_x removed. The post-control emission rate was estimated at 286 lb NO_x/MMCF

Time necessary to install controls: A total of 14 months for each turbine is the estimated time to install DLN control technology with liner upgrade. This estimation is from EPNG Engineering Department and includes time for engineering, permitting, and installation.

Energy and non-air quality impacts: The turbine liner replacement would reduce the heat rate of the turbines, thereby increasing the fuel usage. The DLN control technology would require the GE gas turbines to be converted from regenerative-cycle to simple-cycle, reducing the heat rate and increasing the fuel usage. A 40% fuel use increase is expected based on a vendor quote obtained. The increased fuel usage will result in additional CO, VOC, and SO_2 formations.

The cost of controls for the turbines are summarized below in Table 5-1. For the GE gas turbines, cost for each technically feasible control technology is greater than $5,000 per ton of NO_x removed (based on current and 2028 dollars). EPNG currently employs good combustion practices through routine inspection and maintenance of the turbine and will continue with its current schedule and practices. Good combustion practice is the only feasible control option.

Table 5-1. Cost of Controls

Unit	Projected 2028 Cost of Control for Technically Feasible Controls ($/ton)	
	Liner Upgrade + Dry Low-NO_x/Simple Cycle	Selective Catalytic Reduction (SCR)
TURBINE-1	14,090	10,163
TURBINE-2	12,876	9,868

APPENDIX A: CONTROL COST ANALYSIS

Table A-1. EPNG - Willcox - RH 2PP - 4FA - Summary - Turbines

Equipment				Baseline Operations		Baseline NOx Emissions			Technically Feasible Controls	
Type	Make & Model	Rating [1] (hp at 80 deg F)	ADEQ Unit Description [2]	Hours of Operation [3] (hr/yr)	Fuel Usage [3] (MMcf/yr)	(tpy) [3]	(g/hp-hr) [4]	Four Factor Analysis Statutory Factor	Liner Upgrade + Dry Low-NOx/Simple Cycle	Selective Catalytic Reduction (SCR)
Gas Turbine Engine	GE M3142R-J	10,110	TURBINE-1	4,619	281.624	134.72	-	Cost of Control ($/ton)	14,090	10,163
								Time Necessary for Installation (months)	14	14
								Energy and Non-Air Environmental Impacts	Will reduce heat rate, and increase fuel use.	Requires ammonia storage, handling and delivery system, which would include vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. In addition, an SCR system catalyst would increase the backpressure on the engine. Spent catalyst is classified as a hazardous waste. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Storage and transportation of ammonia increases risk of human exposure.
								Remaining Useful Life of the Source	15	15
Gas Turbine Engine	GE M3142R-J	10,110	TURBINE-2	5,079	334.870	157.44	-	Cost of Control ($/ton)	12,876	9,868
								Time Necessary for Installation (months)	14	14
								Energy and Non-Air Environmental Impacts	Will reduce heat rate, and increase fuel use.	Requires ammonia storage, handling and delivery system, which would include vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. In addition, an SCR system catalyst would increase the backpressure on the engine. Spent catalyst is classified as a hazardous waste. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Storage and transportation of ammonia increases risk of human exposure.
								Remaining Useful Life of the Source	15	15

[1] Per ADEQ Air Quality Class I Permit 61325

[2] Per email from Mariana Armendariz, ADEQ, to Weiwen Daly, EPNG, on September 13, 2019.

[3] Per 2028 projection provided by Weiwen Daly, EPNG, to ADEQ on August 1, 2019.

Table A-2. EPNG - Willcox - RH 2PP - 4FA - GE M3142R-J Turbine (TURBINE-1) - Control Review & Cost Analysis (Using 2028 Projected Emissions)

Technical Feasibility													
Parameter		**Liner Upgrade + Dry Low-NOx/Simple Cycle**		**Selective Catalytic Reduction (SCR)**		**Steam Injection**		**Water Injection**		**Selective Non-Catalytic Reduction (SNCR)**		**EM_X™/$SCONO_X$™ Technology (oxidation catalyst)**	
Value	**Units**	**Value**	**Reference**	**Value**	**Reference**	**Value**	**Reference**	**Value**	**Reference**	**Value**	**Reference**	**Value**	**Reference**
Is this technology feasible?		Yes		Yes		No		No		No		No	
If not, please explain						Steam injection is not available for Frame 3 turbines.	[8]	Water injection is not available for Frame 3 turbines.	[8]	SNCR is only effective in a relatively high, narrow temperature range (greater than 1600 °F). The exhaust from this turbine is around 800 °F.	[13]	The operating temperature range for this technology is limited to 300 to 700 °F. The exhaust from this turbine is around 800 deg F making this technology technically infeasible for simple-cycle operation.	[12]
If Control Technology is Technically Feasible, Complete the Following													
Potential NOx Reduction													
NOx Reduction	%	69%	[4], [7]										
Rating	MW	7.54	[1]										
Operating Hours	hr/yr	4,619	2028 Projections	See Table A-4									
Inlet NOx	tpy	134.72	2028 Projections										
Outlet NOx	tpy	41.96	Calculated										
NOx Reduced	tpy	93	Calculated										
Capital Implementation Costs													
Unit Cost	$/kW	370.74	Calculated										
Total Cost	$	$2,795,000	[8], [9]										
Cost Obtained from Vendor Quote?	Yes / No	Yes	[8], [10]										
Capital Recovery Factor	%	10.98%	[2]										
Annualized Cost	$/yr	$306,876	Calculated	See Table A-4									
Admin, Taxes, Insurance	$/yr	$111,800	[3]										
Fixed Operating Cost	$/yr	$184,717	[5], [6]										
Variable Operating Cost - Fuel	$/yr	$442,175	[5], [6], [15]										
Total Annual Cost	$/yr	$1,045,568	Calculated										

Table A-2. EPNG - Willcox - RH 2PP - 4FA - GE M3142R-J Turbine (TURBINE-1) - Control Review & Cost Analysis (Using 2028 Projected Emissions)

Technical Feasibility															
Parameter		Liner Upgrade + Dry Low-NOx/Simple Cycle		Selective Catalytic Reduction (SCR)		Steam Injection		Water Injection		Selective Non-Catalytic Reduction (SNCR)		EM_X™/$SCONO_X$™ Technology (oxidation catalyst)	
Value	Units	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference
Cost of Control (Statutory Factor 1)															
2019 Cost of Control	$/ton removed	11,272	Calculated	8,130	Calculated								
2028 Cost of Control	$/ton removed	14,090	[16]	10,163	[16]								
Post-Control Emission Rate	lb/MMCF	298.01	Calculated	293.59	Calculated								
Averaging Period		30-day rolling	Calculated	30-day rolling	Calculated								
Time Necessary for Installation (Statutory Factor 2)															
Modification time	months	8	[14]	8	[14]								
Permitting	months	4	Estimated	4	Estimated								
Engineering	months	2	Estimated	2	Estimated								
Total Time Necessary for Compliance	months	14	Estimated	14	Estimated								
Energy and Non-Air Environmental Impacts (Statutory Factor 3)															
Energy and Non-Air Environmental Impacts		Will reduce heat rate, and increase fuel use.	Process Knowledge	Requires ammonia storage, handling and delivery system, which would include vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. In addition, an SCR system catalyst would increase the backpressure on the engine. Spent catalyst is classified as a hazardous waste. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Storage and transportation of ammonia increases risk of human exposure.	[11]								
Remaining Useful Life of the Source (Statutory Factor 4)															
Remaining Useful Life	Years	15	Estimated	15	Estimated								

Table A-2. EPNG - Willcox - RH 2PP - 4FA - GE M3142R-J Turbine (TURBINE-1) - Control Review & Cost Analysis (Using 2028 Projected Emissions)

Technical Feasibility													
Parameter		Liner Upgrade + Dry Low-NOx/Simple Cycle		Selective Catalytic Reduction (SCR)		Steam Injection		Water Injection		Selective Non-Catalytic Reduction (SNCR)		EM_X™/$SCONO_X$™ Technology (oxidation catalyst)	
Value	Units	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference

[1] Data from ADEQ Air Quality Class I Permit 61325

[2] Capital Recovery factor (CRF) calculated as follows

Interest Rate	7%	Per EPA Air Pollution Control Cost Manual Chapter 2 Cost Estimation: Concepts and Methodology
Remaining useful life of source	15	
Capital Recovery Factor	10.98%	

Note that the number of years corresponds to the remaining life of the unit after 2028, the earliest time that controls are expected to be installed. Per EPA "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" dated August 20, 2019:
"Typically, the remaining useful life of the source itself will be longer than the useful life of the emission control system under consideration unless there is an enforceable requirement for the source to cease operation sooner ... annualized compliance costs are typically based on the useful life of the control equipment rather than the life of the source, unless the source is under an enforceable requirement to cease operation"

[3] Admin, Taxes, Insurance assumed to be: 4.00% Per EPA Air Pollution Control Cost Manual, Seventh Ed., 2017, Sect. 2.6.5.8, pg 2-35

[4] Inlet concentration per average of 2016, 2017, and 2018 Emissions Test Summary

[5] Chemical Engineering Plant Cost Index

Year	Index
1995	381.1
1996	381.7
1997	386.5
1998	389.5
1999	391.8
2000	394.1
2001	394.3
2002	395.6
2003	402.0
2004	444.2
2005	468.2
2006	499.6
2007	525.4
2008	575.4
2009	521.9
2010	550.8
2011	593.2
2012	584.6
2013	567.3
2014	576.1
2015	556.8
2016	541.7
2017	567.5
2018	603.1
2019	-

[6] Cost per Onsite Sycom Energy Corporation, "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines", Contract No. DE-FC02-97CHIO877, November 5, 1999.

Fuel cost 2.5 $/MMBTU = 2.55 $/MSCF

[7] Target NOx outlet of 35 ppm per vendor quote.

[8] Per information received from EPNG Engineering Department on August 1, 2019 and August 2, 2019

[9] Per EPA "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" dated August 20, 2019: "... every source-specific cost estimate used to support an analysis of control measures must be documented in the SIP."

[10] Per EPA "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" dated August 20, 2019: "...states may place greater weight on vendor quotes that represent an offer to enter a contract at that price than on estimates without an offer to enter a contract."

[11] Per "Title V Significant Modification to Request Alternative NOx RACT Emission Limit" for Texas Eastern Transmission, L.P. Lambertville, New Jersey submitted November 2017.

[12] Per Application for a Non-Major Comprehensive Plan Approval for Northeast Energy Direct Project Market Path Mid 3 Compressor Station Northfield, MA, submitted November 2015

[13] Per EPA Cost Control Manual, Chapter 1: Selective Noncatalytic Reduction.

[14] Per estimate received from Jonathan Goss, EPNG on 10/3/2019. Modifications will require 8 months; replacements will require 12 months.

[15] A 40% fuel rate increase is expected for DLN per vendor quote received on August 1, 2019. Current fuel rate is based off of average of 2016, 2017, and 2018 usages.

[16] Adjusted current price to 2028 projected price using an inflation rate of: 25 %

Table A-3. EPNG - Willcox - RH 2PP - 4FA - GE M3142R-J Turbine (TURBINE-2) - Control Review & Cost Analysis (Using 2028 Projected Emissions)

Technical Feasibility													
Parameter		**Liner Upgrade + Dry Low-NOx/Simple Cycle**		**Selective Catalytic Reduction (SCR)**		**Steam Injection**		**Water Injection**		**Selective Non-Catalytic Reduction (SNCR)**		**EM_X™/$SCONO_X$™ Technology (oxidation catalyst)**	
Value	**Units**	**Value**	**Reference**	**Value**	**Reference**	**Value**	**Reference**	**Value**	**Reference**	**Value**	**Reference**	**Value**	**Reference**
Is this technology feasible?		Yes		Yes		No		No		No		No	
If not, please explain						Steam injection is not available for Frame 3 turbines.	[8]	Water injection is not available for Frame 3 turbines.	[8]	SNCR is only effective in a relatively high, narrow temperature range (greater than 1600 °F). The exhaust from this turbine is around 800 °F.	[13]	The operating temperature range for this technology is limited to 300 to 700 °F. The exhaust from this turbine is around 800 deg F making this technology technically infeasible for simple-cycle operation.	[12]
If Control Technology is Technically Feasible, Complete the Following													
Potential NOx Reduction													
NOx Reduction	%	70%	[4], [7]	See Table A-4									
Rating	MW	7.54	[1]										
Operating Hours	hr/yr	5,079	2028 Projections										
Inlet NOx	tpy	157.44	2028 Projections										
Outlet NOx	tpy	47.81	Calculated										
NOx Reduced	tpy	110	Calculated										
Capital Implementation Costs													
Unit Cost	$/kW	370.74	Calculated	See Table A-4									
Total Cost	$	$2,795,000	[8], [9]										
Cost Obtained from Vendor Quote?	Yes / No	Yes	[8], [10]										
Capital Recovery Factor	%	10.98%	[2]										
Annualized Cost	$/yr	$306,876	Calculated										
Admin, Taxes, Insurance	$/yr	$111,800	[3]										
Fixed Operating Cost	$/yr	$184,717	[5], [6]										
Variable Operating Cost - Fuel	$/yr	$525,776	[5], [6], [15]										
Total Annual Cost	$/yr	$1,129,169	Calculated										

Table A-3. EPNG - Willcox - RH 2PP - 4FA - GE M3142R-J Turbine (TURBINE-2) - Control Review & Cost Analysis (Using 2028 Projected Emissions)

Technical Feasibility													
Parameter		Liner Upgrade + Dry Low-NOx/Simple Cycle		Selective Catalytic Reduction (SCR)		Steam Injection		Water Injection		Selective Non-Catalytic Reduction (SNCR)		EM_X™/$SCONO_X$™ Technology (oxidation catalyst)	
Value	Units	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference
Cost of Control (Statutory Factor 1)													
2019 Cost of Control	$/ton removed	10,300	Calculated	7,895	Calculated								
2028 Cost of Control	$/ton removed	12,876	[16]	9,868	[16]								
Post-Control Emission Rate	lb/MMCF	285.56	Calculated	289.67	Calculated								
Averaging Period		30-day rolling	Calculated	30-day rolling	Calculated								
Time Necessary for Installation (Statutory Factor 2)													
Modification time	months	8	[14]	8	[14]								
Permitting	months	4	Estimated	4	Estimated								
Engineering	months	2	Estimated	2	Estimated								
Total Time Necessary for Compliance	months	14	Estimated	14	Estimated								
Energy and Non-Air Environmental Impacts (Statutory Factor 3)													
Energy and Non-Air Environmental Impacts		Will reduce heat rate, and increase fuel use.	Process Knowledge	Requires ammonia storage, handling and delivery system, which would include vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. In addition, an SCR system catalyst would increase the backpressure on the engine. Spent catalyst is classified as a hazardous waste. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Storage and transportation of ammonia increases risk of human exposure.	[11]								
Remaining Useful Life of the Source (Statutory Factor 4)													
Remaining Useful Life	Years	15	Estimated	15	Estimated								

Table A-3. EPNG - Willcox - RH 2PP - 4FA - GE M3142R-J Turbine (TURBINE-2) - Control Review & Cost Analysis (Using 2028 Projected Emissions)

Technical Feasibility													
Parameter		Liner Upgrade + Dry Low-NOx/Simple Cycle		Selective Catalytic Reduction (SCR)		Steam Injection		Water Injection		Selective Non-Catalytic Reduction (SNCR)		EM_X™/$SCONO_X$™ Technology (oxidation catalyst)	
Value	Units	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference

[1] Data from ADEQ Air Quality Class I Permit 61325

[2] Capital Recovery factor (CRF) calculated as follows

Interest Rate	7%	Per EPA Air Pollution Control Cost Manual Chapter 2 Cost Estimation: Concepts and Methodology
Remaining useful life of source	15	
Capital Recovery Factor	10.98%	

Note that the number of years corresponds to the remaining life of the unit after 2028, the earliest time that controls are expected to be installed. Per EPA "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" dated August 20, 2019: *"Typically, the remaining useful life of the source itself will be longer than the useful life of the emission control system under consideration unless there is an enforceable requirement for the source to cease operation sooner ... annualized compliance costs are typically based on the useful life of the control equipment rather than the life of the source, unless the source is under an enforceable requirement to cease operation"*

[3] Admin, Taxes, Insurance assumed to be: 4.00% Per EPA Air Pollution Control Cost Manual, Seventh Ed., 2017, Sect. 2.6.5.8, pg 2-35

[4] Inlet concentration per average of 2016, 2017, and 2018 Emissions Test Summary

[5] Chemical Engineering Plant Cost Index

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2013	567.3
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2019	-

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Fuel cost 2.5 $/MMBTU = 2.55 $/MSCF

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[13] Per EPA Cost Control Manual, Chapter 1: Selective Noncatalytic Reduction.

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[16] Adjusted current price to 2028 projected price using an inflation rate of: 25 %

Table A-4. EPNG - Willcox - RH 2PP - 4FA - SCR for Turbines - Costs

Parameter	Short name	Calculation	El Paso Natural Gas [1]	El Paso Natural Gas [1]	Units	Reference
Location			Willcox	Willcox		
Turbine Make			GE	GE		
Turbine Model			M3142R-J	M3142R-J		
ADEQ Unit Description			TURBINE-1	TURBINE-2		
Exhaust Parameters						
Heat Input Rate	Q_b		72.2	72.2	MMBtu/hr	Per 2019 Permit Renewal Application. Heat input adjusted to turbine rating at 80 deg F.
Exhaust Temperature			809.0	815.7	deg F	Per average of 2016, 2017, and 2018 Emissions Test Summary
Exhaust Temperature			704.8	708.5	deg K	
Exhaust Flow	$q_{fluegas}$		210,833	220,114	acfm	Per average of 2016, 2017, and 2018 Emissions Test Summary
Operating Temperature	T	Vendor Data	860	860	deg F	
Operating Hours Per Year	AOH	Max	4,619	5,079	hours	
Inlet Concentration	NOx_{in}		0.96	0.95	lb/MMBtu	Per average of 2016, 2017, and 2018 Emissions Test Summary
Inlet Concentration	NOx_{in}		112	115	ppmv	Per average of 2016, 2017, and 2018 Emissions Test Summary
Outlet Concentration	NOx_{out}		34	35	ppmv	70% control efficiency per EPA Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032
Outlet Concentration	NOx_{out}		0.288	0.284	lb/MMBtu	
Available Cost Data						
Capital Cost of Ammonia Catalyst	$CC_{initial}$	$(8000/m^3)/(35.1347\ ft^3/m^3)$	249	249	$\$/ft^3$	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, footnote 4. Adjusted from 2010 dollar.
Capital Cost of 19% Ammonia	$CC_{NH3solu}$	$\$3.56/gal/Den_{NH3}$	0.49	0.49	$/lb	Vendor quotes from 2011 to 2013. Adjusted from 2012 dollar.
Electricity Rate	$TAIE_{cost}$		0.108	0.108	$/kWh	Per September 2019 Electricity Bill at Willcox Compressor Station.
Chemical Properties and Constants						
19% Ammonia Solution Density	Den_{NH3}		7.51	7.51	lbs/gal	Per CFIndustries Aqua Ammonia 19% Safety Data Sheet.
Ammonia MW	$M_{reagent}$		17.03	17.03	g/mol	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction
NO_2 MW	M_{NOx}		46.01	46.01	g/mol	
Ratio of Equivalent Moles of NH_3 per Mole of Reagent Injected	$SR_{theoretical}$		1	1	mol NH_3:mol reagent	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction
Ratio of Equivalent Moles of NH_3 per mole of NOx	SRF		1.05	1.05	mol NH3:mol NOx	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.3.7
Constant 1	C1		7	7	ft	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.3.12
Constant 2	C2		9	9	ft	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.3.12
SCR Design Data						
Empty Catalyst Layers	n_{empty}		0	0	layers	Value assumed for lowest capital cost
Nominal Height of Each Catalyst Layer	h'_{layer}		3.1	3.1	ft	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.3.12
Number SCR Chambers	n_{scr}		1	1	chamber	Value assumed for lowest capital cost
Allowable Slip	Slip		2	2	ppm	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.2.2. Minimum range of allowable slip.
Pressure Drop due to Duct	ΔP_{duct}		3	3	in	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.5
Pressure Drop due to Catalyst	$\Delta P_{catalyst}$		1	1	in	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.5
Operating Life of Catalyst in Hours	$h_{catalyst}$		24,000	24,000	hours	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.5
NOx Removal Efficiency	η_{NOx}	$(NOx_{in}-NOx_{out})/NOx_{in}*100\%$	70	70	%	Calculated
Cross Sectional Area of Catalyst	$A_{catalyst}$	$q_{fluegas}/(16ft/sec \times 60\ sec/min)$	220	229	ft^2	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.28.
Cross Sectional area of SCR reactor	A_{SCR}	$A_{catalyst}*1.15$ (15% greater than $A_{catalyst}$)	253	264	ft^2	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.29.
Temp Adjustment	T_{adj}	$15.16-(0.03937*T)+(0.0000274*(T^2))$	1.57	1.57	deg F	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.27
Slip Adjustment	$Slip_{adj}$	$(1.2835-(0.0567*Slip))$	1.17	1.17		Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.24
Inlet NOx Adjustment	NOx_{adj}	$(0.8524+(0.3208*NOX_{in}))$	1.16	1.16		Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.25
NOx Efficiency Adjustment	η_{adj}	$(0.2869+(1.058*\eta_{NOx}))$	1.03	1.03		Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.23
Volume of Catalyst	Vol_{cat}	$2.81*Q_b*\eta_{adj}*NOX_{adj}*Slip_{adj}*T_{adj}/n_{scr}$	443	442	ft^3	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.22
Height of catalyst layer	h_{layer}	$Vol_{catalyst}/(N_{layer}*A_{catalyst})+1$	3	3	ft	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.32
Number of catalyst layers	n_{layer}	$Vol_{catalyst}/(h'_{layer}*A_{catalyst})$	1	1	layers	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.31
Total Number of catalyst layers	n_{total}	$n_{layer} + n_{empty}$	1	1	layers	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.33
Height of SCR	h_{scr}	$n_{total}*(C1+h_{layer})+C2$	19	19	ft	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.34
Mass flow of reagent	$m_{reagent}$	$(NOx_{in}*Q_b*\eta_{NOx}*SRF*M_{reagent})/(M_{NOx})$	19	19	lb/hr	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.35
Mass flow of solution	m_{sol}	$m_{reagent}/C_{sol}$	99	98	lb/hr	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.36

Table A-4. EPNG - Willcox - RH 2PP - 4FA - SCR for Turbines - Costs

Parameter	Short name	Calculation	El Paso Natural Gas [1]	El Paso Natural Gas [1]	Units	Reference
Direct Costs						
Catalyst Cost	f(Vol)	Vol_{cat}*$CC_{initial}$	110,570	110,178	$	Calculated
Ammonia Flow Adjustment	f(NH3)	$411/(lb/hr)*$m_{reagent}$/$Q_b$-$47.3/MMBtu/hr	93	91	$/(MMBtu/hr)	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.38 Adjusted from 1998 dollar
SCR height Adjustment	f(h_{scr})	$6.12/(ft-MMBtu/hr)*$h_{scr}$-$187.9/MMBtu/hr	-111	-112	$/(MMBtu/hr)	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.37 Adjusted from 1998 dollar
New "Boiler" Adjustment	f(new)	-$728/MMBtu/hr	-1,127	-1,127	$/(MMBtu/hr)	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.40 Adjusted from 1998 dollar
New Bypass	f(bypass)	$127/MMBtu/hr	197	197	$/(MMBtu/hr)	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.42 Adjusted from 1998 dollar
Ammonia Slip Monitoring	MON_{cost}	70,000	80,891	80,891	$	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.2.2 Adjusted from 2009 dollar
Total Direct Cost	DC	Q_b[3,380/MMBtu/hr+f(h_{scr})+f(NH3)+f(new)+f(bypass)](3500/Q_b)$^{0.35}$+f(Vol)+MON_{cost}	1,395,095	1,393,836	$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.36 Adjusted from 1998 dollar
Indirect Costs						
Annual Reference Method Testing	PT_{cost}	Budgetary Cost	15,000	5,000	$	Per email received from Weiwen Daly, EPNG on November 4, 2019.
General Facilities	GF_{cost}	0.05*DC	69,755	69,692	$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Table 2.5
Engineering and Home Office Fees	EO_{cost}	0.10*DC	139,510	139,384	$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Table 2.5
Process Contingency	PC_{cost}	0.05*DC	69,755	69,692	$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Table 2.5
Total Indirect Installation Costs	B	PT_{cost}+GF_{cost}+EO_{cost}+PC_{cost}	294,019	283,767	$	Calculated
Project Contingency	C	0.15*(DC+B)	253,367	251,640	$	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.4.1
Total Plant Costs	D	DC+B+C	1,942,482	1,929,243	$	-
Preproduction Costs	G	0.02*D	38,850	38,585	$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Table 2.5
Inventory Capital	H	$CC_{NH3solu}$*m_{sol}*14 days*24 hr/day	16,300	16,082	$	Based on 14 days of SCR operation, 24 hrs/day
Total Capital Investment	TCI	D+G+H	**1,997,631**	**1,983,910**	**$**	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Table 2.5
Direct Annual Costs						
Operator Labor Rate	OL_{cost}	AOH*50% manned operation*$60/hr	154,279	169,627	$	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.5, adjusted from 2016 dollar
Supervisor Labor	SL_{cost}	0.15*OL_{cost}	23,142	25,444	$	Per 2002 EPA Cost Manual
Annual Maintenance Costs	AM_{cost}	0.015*TCI*2	59,929	59,517	$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.46 (multiplied by two to include maintenance labor and materials)
Annual Reagent Costs	AR_{cost}	$CC_{NH3solu}$*m_{sol}*AOH	224,081	243,082	$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.58
Annual Electricity Costs	AE_{cost}	0.105*Qb*(NOx_{in}*η_{NOx}+0.5(ΔP_{duct}+n_{total}+$\Delta P_{catalyst}$))*AOH*TAIE_{cost}	10,111	11,079	$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equations 2.48 and 2.49
Quarterly Portable Tests		4*600	2,400	2,400	$	$600 per test, performed quarterly
Catalyst Replacement Costs	CR_{cost}	n_{scr}*Vol_{cat}*($CC_{initial}$/n_{layer})	110,570	110,178	$	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.63.
Future Worth Factor	FWF	i*[1/(1+i)$^{hcatalyst/AOH}$-1)	0.2	0.2		Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equations 2.65 and 2.66
Annual Catalyst Replacement Cost	ACR_{cost}	CR_{cost}*FWF	21,249	23,284	$	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.64.
Direct Annual Costs	DA_{cost}	OL_{cost}+SL_{cost}+AM_{cost}+AR_{cost}+AE_{cost}+$RATA_{cost}$+ACR_{cost}	**605,761**	**644,611**	**$/year**	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.56.

Table A-4. EPNG - Willcox - RH 2PP - 4FA - SCR for Turbines - Costs

Parameter	Short name	Calculation	El Paso Natural Gas [1]	El Paso Natural Gas [1]	Units	Reference
Indirect Annual Costs						
Administrative Charges	A_{cost}	0.03*OLcost+0.4*AMcost	28,600	28,896	$/year	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.69.
Overhead Costs		$0.6*(OL_{cost}+SL_{cost}+AM_{cost})$	142,410	152,753	$/year	Per 2002 EPA Cost Manual, Page 2-34.
Indirect Annual Costs	IAcost	A_{cost}	171,010	181,649	$	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.68
Annualized Capital Cost	AC_{cost}	CRF*TCI	133,922	133,003	$/year	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.70
Interest Rate	i		7%	7%		Per EPA Cost Manual Chapter 2 Cost Estimation: Concepts and Methodology
SCR System Life	Life		15	15	years	Per ADEQ guidance, equipment life of turbine from time of installation (2028).
Capital Recovery Factor	CRF	$i(1+i)^{life}/((1+i)^{life}-1)$	0.07	0.07		Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.71
Total Annual Costs	TAC	ACcost+DAcost+IAcost	910,693	959,262	$/year	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.72.
Indirect Annual Costs						
NOx Removed Per Year	$NOx_{removed}$	$NOx_{in}*\eta_{NOx}*Q_b*AOH/2{,}000$ lb/ton	112	122	ton/yr	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.11
Cost Effectiveness		**$TAC/NOx_{removed}$**	**8,130**	**7,895**	**$/ton**	**Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.73**

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