REGIONAL HAZE FOUR-FACTOR ANALYSIS

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

Arizona Department of Environmental Quality

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December 2019

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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 Williams 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 Williams Compressor Station.

Table 1-1. EPNG Williams – RH 2PP 4FA – Conclusions

Emission Unit Identifier	Pollutant	Proposed Control	Post Control Emission Rate (tpy)	Proposed Emission Rate Averaging Period
RECIP-1	NO_x	Good Combustion Practices	Not Applicable	Not Applicable
RECIP-2	NO_x	Good Combustion Practices	Not Applicable	Not Applicable
RECIP-5	NO_x	Good Combustion Practices	Not Applicable	Not Applicable
TURBINE-1	NO_x	Good Combustion Practices	Not Applicable	Not Applicable

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 the EPNG Williams 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 Williams Compressor Station is located in Coconino County, about 3 miles north of exit 171 of I-40. The nearest Class I area to the station is the Sycamore Canyon Wilderness, located 29 km away from the station. ADEQ calculated the "Q/d" for this source to be 55. Table 3-1 provides a list of all equipment at the Williams 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. EPNG Williams – RH 2PP 4FA – Subject Sources

Equipment Type	Max Capacity	Make	Model	Serial Number	ADEQ Unit Description	Installation/ Manufacturing Date
2SLB Reciprocating Engine	2,000 hp	Clark	TLA-6	73563	RECIP-1	1956
2SLB Reciprocating Engine	2,000 hp	Clark	TLA-6	73557	RECIP-2	1956
2SLB Reciprocating Engine	3,400 hp	Clark	TLA-10	79032	RECIP-5	1960
Gas Turbine	22,150 hp	General Electric	M5322R	282044	TURBINE-1	1993

[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. TURBINE – NO_X CONTROLS

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

4.1.1. Identification of Potential Control Technologies and Elimination of Technically Infeasible Controls

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 turbine. 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."

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 is described in detail below. Additionally, infeasible controls are identified to satisfy Steps 1 and 2.

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 Williams 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. Water and steam injection use the same operating principle to reduce NO_x emissions but are further analyzed separately because of differing considerations between liquid and vaporized water.

Water or Steam Injection has been determined to be technically feasible for the GE gas turbine at Williams Compressor Station. Steam injection would require vaporizing water before injection, which requires supplemental energy input.

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. During the 1st planning period of Regional Haze, the EPA identified a liner upgrade as a possible NO_x reducing technology for the General Electric (GE) M5322R turbine at the Williams Compressor Station.[4]

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[4] See spreadsheet "Non EGU_RP_Ch5.xlsx" in the index on *www.regulations.gov* under docket number EPA–R09–OAR–2013–0588.

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.[5] 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 turbine. 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 GE Frame 5 gas turbine. EPNG was able to obtain a cost estimate from GE for the control technology; as such, DLN has been considered technically feasible for the GE gas turbine. 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 turbine will have adverse impacts on the efficiency of the gas turbine, 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.[6]

The GE gas turbine at Williams Compressor Station is a regenerative-cycle turbine, with an exhaust temperature greater than 900 °F. EM_X™/$SCONO_X$™ applications on turbines with outlet temperatures this high have not been identified. Consequently, it has been concluded that EM_X™/$SCONO_X$™ is not technically feasible for control of NO_x emissions from the GE turbine.

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

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

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. The exhaust temperature of the GE gas turbine assessed here is above 900 °F which is greater than the upper limit of 850 °F. Per AP-42 Section 3.1, at this temperature, NO_x and NH_3 can pass through the catalyst unreacted. Based on the exhaust temperature range of the turbine, a flue gas-cooling scheme would be required to make SCR a technically feasible technology for this unit.

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:

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

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

[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.

[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.

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 turbine assessed here. For this reason, it has been determined that this control technology is not feasible for the GE gas turbine at Williams 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 turbine at Williams 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 Williams 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 five potentially feasible control technologies are SCR, water injection, steam injection, combustion liner upgrade and Low NO_x Burner design (DLN), and good combustion practices. The control efficiency associated with each control technology is summarized in Table 4-1.

Table 4-1. EPNG Williams – RH 2PP 4FA – Turbine - Potentially Feasible NO_x Control Technologies

Rank	Control Technology	Potential NO_X Control Efficiency (%) [1]
1	Liner upgrade and DLN	79
2,3	Steam injection	75
	Water injection	75
4	SCR	70
5	Good Combustion Practices	Base Case, already in use

[1] NOx control efficiencies calculated as detailed in Appendix A

[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 turbine.

The cost of each control technology was estimated using published methods,[10,11,12] 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 the turbine is estimated to be 15 years (after 2028, which is the earliest time that the controls are expected to be installed). The choice of control technology does not affect the remaining useful life of the GE gas turbine. Cost effectiveness for each potential control technology is discussed below.

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

4.1.3.1. Lean Head End Combustion Liner Upgrade and DLN Control Technology

Cost of Control Technology: The total annualized cost was estimated at $2.24 million to remove 231 tpy of NO_x. This equates to a cost effectiveness of $9,733 per ton of NO_x removed. The projected 2028 cost is $12,167 per ton of NO_x removed. The post-control emission rate was estimated at 153.56 lb NO_x /MMCF.

Time necessary to install controls: A total of 14 months 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 DLN control technology would require the GE gas turbine 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 formation.

4.1.3.2. Steam Injection

Cost of Control Technology: For steam injection, the total annualized cost was estimated at $1.04 million to remove 219 tpy of NO_x. This equates to a cost effectiveness of $4,750 per ton of NO_x removed. The projected 2028 cost is $5,938 per ton of NO_x removed. The post-control emission rate was estimated at 184.27 lb NO_x /MMCF.

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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] NESCAUM, "Status Report on NOx for Industrial Boilers, Gas Turbines, IC Engines, and Cement Kilns; Control Technologies and Cost Effectiveness", December 2000, pg IV-47. Cost was escalated using the Chemical Engineering Plant Cost Index

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

Time necessary to install controls: A total of 14 months is the estimated time to install steam injection technology. This estimation is from the EPNG Engineering Department and includes time for engineering, permitting, and installation.

Energy and non-air quality impacts: Steam injection would increase the overall fuel usage of the source because of multiple factors. Injecting steam reduces the thermal efficiency of the turbine, thereby requiring more fuel to achieve the necessary power output. Using steam would require an additional fuel gas supply of 16,000 scfh to vaporize the water.

Producing and transporting large amount of high purity water to a remote area would use natural resources for fuel and would have associated energy and environmental impacts. A vendor quote estimated that a demineralized water consumption rate of 30 gpm would be required to achieve the desired control efficiency. This is important especially in dry regions such as Arizona. Disposal of waste water is another add-on expense.

4.1.3.3. Water Injection

Cost of Control Technology: For water injection, the total annualized cost was estimated at $1.00 million to remove 219 tpy of NO_x. This equates to a cost effectiveness of $4,579 per ton of NO_x removed. The projected 2028 cost is $5,724 per ton of NO_x removed. The post-control emission rate was estimated at 184.27 lb NO_x /MMCF.

Time necessary to install controls: A total of 14 months is the estimated time to install water injection technology. This estimation is from EPNG Engineering Department and includes time for engineering, permitting, and installation.

Energy and non-air quality impacts: Water injection would increase the overall fuel usage of the source because of multiple factors. Injecting water reduces the thermal efficiency of the turbine, thereby requiring more fuel to achieve the necessary power output. Producing and transporting large amount of high purity water to a remote area would use natural resources for fuel and would have associated energy and environmental impacts. A vendor quote estimated that a demineralized water consumption rate of 30 gpm would be required to achieve the desired control efficiency. This is important especially in dry regions such as Arizona. Disposal of waste water is another add-on expense.

4.1.3.4. Selective Catalytic Reduction (SCR)

Cost of Control Technology: The total annualized cost of the SCR was estimated to be $1.75 million to remove 229 tpy of NO_x. This equates to a cost effectiveness of $ $7,629 per ton of NO_x removed. The projected 2028 cost is $9,536 per ton of NO_x removed. The post-control emission rate was estimated at 205.33 lb NO_x /MMCF.

Time necessary to install controls: A total of 14 months is the estimated time to install SCR system. This estimation is from EPNG Engineering Department 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.[13]

In addition, it should be noted that in order to construct an SCR system, the building that houses the turbine 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.

4.2. RECIPROCATING ENGINES – NO_X CONTROLS

This section presents the step-wise review of control options for NO_x for the reciprocating engines at the Williams Compressor Station.

4.2.1. Identification of Potential Control Technologies

In order to identify all feasible control technologies, the RBLC database, WRAP guidance, as well as technical literature was reviewed. Using these sources, potentially applicable NO_x control technologies for lean burn engines were identified based on the principles of control technology and engineering experience for general combustion units. Control options include:

- Selective Catalytic Reduction (SCR)
- Air-fuel ratio adjustment with high energy ignition
- Low-emission combustion (LEC) retrofit
- Replace three engines with one low NO_x emissions gas turbine
- Replace three engines with electric motors
- Good combustion practices

Step 2 of the top-down control review is to eliminate technically infeasible NO_x control options that were identified in the first step. The feasibility of each control may be identical for all three reciprocating engines or may have differing considerations for each and will be noted as such. The control technologies and their feasibilities are discussed below to satisfy Steps 1 and 2 of the top-down control review.

4.2.1.1. Selective Catalytic Reduction (SCR)

SCR installations typically have an operating range of 450 to 850°F but can operate at slightly higher temperatures.[14] The exhaust temperatures of all three reciprocating engines are within the range of feasibility, as such, they will be considered further in this analysis. It should be noted that reciprocating engines having frequent and rapid load fluctuations can cause variations in exhaust temperature and NO_x concentration which can create problems with the effectiveness of the SCR system.

[13] Per *"Title V Significant Modification to Request Alternative NOx RACT Emission Limit"* for Texas Eastern Transmission, L.P. Lambertville, New Jersey submitted November 2017.
[14] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

4.2.1.2. Air-Fuel Ratio Adjustment

Air-fuel ratio adjustment can be accomplished with an automatic control system. For lean-burn engines, the amount of air in the combustion process is increased which lowers the combustion temperature and reduces NO_x formation. Control efficiencies for lean-burn engines are in the range of 5 to 30 percent, with NO_x outputs reduced to as low as 15 g/hp-hr.[15] At Williams Compressor Station, one TLA-6 engine (RECIP-2) and the TLA-10 engine (RECIP-5) already achieve this NO_x emission rate, making the control infeasible for RECIP-2 and RECIP-5. The remaining engine, TLA-6 (RECIP-1), has a NO_x emission rate of nearly 17 g/hp-hr. Controlled air-fuel ratio adjustment is a feasible control for RECIP-1.

4.2.1.3. Low-Emission Combustion (LEC) Retrofit

Many engine manufacturers have created low-emission combustion designs that operate at leaner air to fuel ratios than typical engine designs. Some manufacturers provide retrofit kits for existing engine models that were not pre-installed with this technology. The low-emission combustion design uses improved swirl patterns to increase air/fuel mixing. Often times, a precombustion chamber is also included which lowers combustion temperatures and NO_x emissions. This technology is available for rich-burn engines, lean-burn engines, and dual-fuel engines. This analysis considers three graduated levels of retrofits which will hereinafter be referred to as the following:

- LEC 1: The first level is adding only a high pressure-fuel injection system, referred hereafter as LEC 1.
- LEC 2: The second level adds three systems combined with LEC 1: turbocharger aero, aftercooler, and an air-fuel ratio control; hereafter referred to as a LEC 2.
- LEC 3: The third level adds three new systems to LEC 2: pre-combustion chambers (PCC), electronic PCC valves, and an auto-balance system, hereafter referred to as LEC 3.

EPNG was able to obtain cost estimates for all three graduated levels of retrofit, as such, LEC are feasible for all engines.

4.2.1.4. Replacement of Three Engines with One Low Emissions Turbine

New gas turbines are typically superior to older reciprocating engines for both power output and emissions. The degree of emissions reduction is evaluated on a case by case basis and depend on the unique engine characteristics of each site. The high capacity of the gas turbine allows for a single unit to replace multiple reciprocating engines. For purposes of this analysis, it is assumed that a Solar Mars 100 gas turbine (15,900 hp) will replace the three reciprocating engines.

The complete replacement of three reciprocating engines with a Solar Mars 100 gas turbine is technically feasible although it requires significant capital investment, extensive engineering oversight, and the compressor station off-line for an extended period, causing service interruption to end users and natural gas suppliers.

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

4.2.1.5. Replacement with Electric Motors

Replacing the reciprocating engines with electrical motors require electricity as a source of power. No emissions would be released directly from the electric motors. Replacement of three engines with electric motors has similar feasibility considerations to the replacement with a single gas turbine. Initial capital, engineering oversight, and downtime incurred would be high, causing service interruption to end users and natural gas suppliers.

The electric motors have no technical barriers to feasibility and could be installed at the site in place of individual reciprocating engines to reduce direct fuel burning emissions.

4.2.1.6. Good Combustion Practices

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 cylinders 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.

Good Combustion Practice has been determined as feasible for the engines at Williams. EPNG has developed Engine Inspection and Maintenance Schedules Best Practices procedures, which are based on manufacturer recommendation, and EPNG has systems in place to ensure that its engines are operated in accordance with this. These practices are currently in use at Williams. No further assessment of these control practices is included in this report.

4.2.2. Rank of Remaining Control Technologies Based on Control Effectiveness

The remaining control technologies are presented in Table 4-2.

Table 4-2. EPNG Williams – RH 2PP 4FA – Engines - Remaining NO_x Control Technologies

Rank	Control Technology	Potential Control Efficiency (%) [1]		
		RECIP-1	RECIP-2	RECIP-5
1	Replacement with electric motors	100	100	100
2	LEC 3	97	96	97
3	Replace three engines with single low emission gas turbine unit	90	90	90
4	Selective Catalytic Reduction (SCR)	88	85	87
5	LEC 2	82	78	80
6	LEC 1	52	40	46
7	Air-fuel ratio adjustment	11	NA	NA
8	Good Combustion Practices	Base Case, already in use		

[1] NO_x control efficiencies calculated as detailed in Appendix A

4.2.3. Evaluation of Impacts for Remaining Control Technologies

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

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

The cost of each control technology was estimated using published methods,[16][17] vendor quotes, and reciprocating engine characteristics. The initial capital costs of engine replacements were amortized over a 20-year period, while the capital costs of add on controls were amortized over a 10-year period due to the ages of these engines. These annualized capital costs were added to the estimated operating costs. Below is each NO_x control method provided in Table 4-2 and its corresponding results of impact analyses.

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

4.2.3.1. Replacement with Electric Motors

Cost of control technology: For RECIP-1, a TLA-6 engine, the total annualized cost of replacing the reciprocating engine with an electric motor was estimated to be $4.03 million to remove 148 tpy of NO_x. This equates to a cost effectiveness of $27,123 per ton of NO_x removed. The projected 2028 cost is $33,903 per ton of NO_x removed. The post-control emission rate was estimated at 0.0 lb NO_x /MMCF.

For RECIP-2, a TLA-6 engine, the total annualized cost of replacing the reciprocating engine with an electric motor was estimated to be $4.88 million to remove 170 tpy of NO_x. This equates to a cost effectiveness of $28,617 per ton of NO_x removed. The projected 2028 cost is $35,771 per ton of NO_x removed. The post-control emission rate was estimated at 0.0 lb NO_x /MMCF.

For RECIP-5, a TLA-10 engine, the total annualized cost of replacing the reciprocating engine with an electric motor was estimated to be $7.81 million to remove 205 tpy of NO_x. This equates to a cost effectiveness of $38,076 per ton of NO_x removed. The projected 2028 cost is $47,595 per ton of NO_x removed. The post-control emission rate was estimated at 0.0 lb NO_x /MMCF.

Time necessary to install controls: A total of 18 months for each engine is the estimated time to install the controls. This estimation is from EPNG Engineering Department and includes time for engineering, permitting, and installation.

Energy and non-air quality impacts: Electric motors would require the installation of new electric utility line and a transmission sub-station. This could introduce other environmental impacts involving such facilities. The generation of the electricity would involve fuel combustion (including those from coal and oil-fired power plants), thereby increasing upstream emissions in NO_x, CO, and VOC .

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[16] 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.

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

Given this cost analysis, replacement of the engines with motors is infeasible.

Remaining useful life of the source: It is assumed that the electric motors would operate for 20 yearsto fully amortize the cost of controls.

4.2.3.2. Low-Emission Combustion (LEC) 3

LEC 3 would include adding high pressure fuel injection, turbocharger modifications, an aftercooler, air-fuel ratio control, pre-combustion chambers, electronic PCC valves, and an auto-balance system.

Cost of Control Technology: For RECIP-1, a Clark TLA-6 engine, the total annualized cost of completely retrofitting the reciprocating engine was estimated to be $901,000 to remove 144 tpy of NO_x. This equates to a cost effectiveness of $6,238 per ton of NO_x removed. The projected 2028 cost is $7,798 per ton of NO_x removed. The post-control emission rate was estimated at 153 lb NO_x /MMCF.

For RECIP-2, a TLA-6 engine, the total annualized cost of completely retrofitting the reciprocating engine was estimated to be $901,000 to remove 165 tpy of NO_x. This equates to a cost effectiveness of $5,457 per ton of NO_x removed. The projected 2028 cost is $6,821 per ton of NO_x removed. The post-control emission rate was estimated at 150 lb NO_x /MMCF.

For RECIP-5, a Clark TLA-10 engine, the total annualized cost of completely retrofitting the reciprocating engine was estimated to be $901,000 to remove 196 tpy of NO_x. This equates to a cost effectiveness of $4,603 per ton of NO_x removed. The projected 2028 cost is $5,754 per ton of NO_x removed. The post-control emission rate was estimated at 150 lb NO_x /MMCF.

See Table 4-3 for the operating cost analysis for LEC 1, LEC 2, and LEC 3.

Table 4-3. EPNG Williams – RH 2PP 4FA – Engines - Clean Burn Conversion - Operating Costs

Parameter	LEC 1	LEC 2 [1]	LEC 3 [1]
Engine Make	Clark	Clark	Clark
Engine Model	TLA6/TLA10	TLA6/TLA10	TLA6/TLA10
Engine Type	2SLB	2SLB	2SLB
DIRECT OPERATNG COST			
Operating Labor			
Operator Labor	$1,440	$2,880	$3,744
(8 hr/mn day @ $60/hr, 3 mn day/year)			
Supervision, 15% of Operator	$216	$432	$562
Maintenance			
Labor	$32,850	$65,700	$85,410
(0.5 hrs/shift @ $60/hr, 3 shifts/day, 365 days/yr)			
Material Cost	$32,850	$65,700	$85,410
Testing			
Annual Reference Method Stack Test	$15,000	$15,000	$15,000
Utilities & Operating Expenses			
Electricity	$5,000	$10,000	$13,000
Total Direct Operating Cost, $/yr	**$87,356**	**$159,712**	**$203,126**
INDIRECT OPERATNG COST			
Overhead			
60% of operators, supervisors, maintenance labor, and material	$40,414	$80,827	$105,075
Total Indirect Operating Cost, $/yr	**$40,414**	**$80,827**	**$105,075**
TOTAL ANNUAL OPERATING COST - 2019 Dollars	**$127,770**	**$240,539**	**$308,201**

[1] Because LEC 1, LEC 2, and LEC 3 are cumulative control options, a retrofit factor of 2 and 2.6 was applied to LEC 2 and LEC 3 respectively to incorporate the additional cost of maintenance, labor, and materials as the control options accumulate.

Time necessary to install controls: It is estimated that a total of 14 months is needed to install controls for each engine. This estimation is from EPNG Engineering Department and includes time for engineering, permitting, and installation.

Energy and non-air quality impacts: The High-Pressure Fuel Injection System requires electricity to operate. The generation of the electricity would most likely involve fuel combustion, thereby increasing emissions. A new transformer may also be needed which could cost millions to install. The cost of a new transformer is not included in this analysis.

Remaining useful life of the source: It is assumed that the engines would continue operating for 10 years after 2028 to fully amortize the cost of controls.

4.2.3.3. Replace Three Engines with Single Low Emission Turbine

Cost of control technology: The total annualized cost of replacing one Clark TLA-10 and two Clark TLA-6 reciprocating engines with a low NO_x emission gas turbine was estimated to be $4.06 million. It was estimated that the installation of the low NO_x emission gas turbine will remove 470 tpy of NO_x from the three Clark engines, equating to a cost effectiveness of $8,636 per ton of NO_x removed. The projected 2028 cost is $10,795 per ton of NO_x removed. The post-control emission rate was estimated at 432 lb NO_x/MMCF. See Table 4-4 for the low emission turbine cost analysis.

Table 4-4. EPNG Williams – RH 2PP 4FA – Engines - Replacement with Low-Emitting Unit

Parameter	Value
Potential NO_x Reduction	
New Turbine Size (hp) [1]	15,900
Outlet NO_x (g/hp-hr) [2]	0.35
Inlet NO_x (tpy) [3]	523.97
Outlet NO_x (tpy) [4]	53.74
NO_x Reduced (tpy)	470.23
Capital Implementation Costs	
Capital Investment ($)	$25,850,426
Total Capital Investment	**$25,850,426**
Capital Recovery Factor [5]	0.0944
Annualized Cost ($/yr)	$2,440,097
Component Exchange ($/yr) [6]	$500,000
Admin, Tax, Insurance ($/yr) [7]	$1,034,017
Annual Reference Method Stack Test ($/yr)	$15,000
Labor Cost - Unmanned Station ($/yr)	$1,440
Supervisor ($/yr)	$216
Maintenance and Materials ($/yr) [8]	$70,000
2019 Total Annual Cost ($/yr)	**$4,060,770**
2028 Total Annual Cost ($/yr) [9]	**$5,075,963**
Cost Effectiveness ($/ton)	**$10,795**

[1] New 15,900 hp Solar Mars 100 to replace Engines RECIP-1, RECIP-2, and RECIP-5.

[2] Per vendor quote.

[3] The new turbine will replace Engines RECIP-1, RECIP-2, and RECIP-5. As such, inlet NO_x includes NO_x emissions from RECIP-1, RECIP-2, and RECIP-5.

[4] Conservatively assumed that new turbine will operate 8,760 hours per year.

[5] For installation of new low-emitting turbine:
Interest Rate: 7%
Remaining useful life of source: 20
Capital Recovery Factor: 0.0944

[6] Solar Component Exchange - Every 40,000 hours of operation hours; assumed every 5 years to be conservative.
$2.5 million cost based on 2019 actual incurred cost.

[7] Admin, Taxes, Insurance assumed to be: 4%
Per EPA Air Pollution Control Cost Manual, Seventh Ed., 2017, Sect. 2.6.5.8, pg 2-35

[8] Maintenance and materials cost obtained from 2019 actual cost for maintaining a Solar Mars 100 at Seligman Compressor Station, AZ.

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

Time necessary to install controls It is estimated that a total of 18 months is needed to replace the three Clark engines with a low NO_x emission gas turbine. This estimation is from EPNG Engineering Department and includes time for engineering, permitting, and installation.

Energy and non-air quality impacts: The overall higher power rating may require additional fuel. The complete replacement of three engines with one low NO_x gas requires significant capital investment, extensive engineering oversite, and the compressor station to be off-line for an extended period, causing service interruption to end users and natural gas suppliers.

Remaining useful life of the source: It is assumed that the new gas turbine would operate for 20 years after 2028 to fully amortize the cost of controls.

4.2.3.4. Selective Catalytic Reduction (SCR)

Cost of Control Technology: For RECIP-1, a Clark TLA-6 engine, the total annualized cost of adding SCR control technology was estimated to be $828,000 to remove 131 tpy of NO_x. This equates to a cost effectiveness of $6,333 per ton of NO_x removed. The projected 2028 cost is $7,916 per ton of NO_x removed. The post-control emission rate was estimated at 678 lb NO_x/MMCF.

For RECIP-2, a Clark TLA-6 engine, the total annualized cost of adding SCR control technology was estimated to be $917,000 to remove 145 tpy of NO_x. This equates to a cost effectiveness of $6,330 per ton of NO_x removed. The projected 2028 cost is $7,913 per ton of NO_x removed. The post-control emission rate was estimated at 719 lb NO_x/MMCF.

For RECIP-5, a Clark TLA-10 engine, the total annualized cost of adding SCR was estimated to be $1.20 million to remove 177 tpy of NO_x. This equates to a cost effectiveness of $6,741 per ton of NO_x removed. The projected 2028 cost is $8,426 per ton of NO_x removed. The post-control emission rate was estimated at 441 lb NO_x/MMCF. See Table 4-5 for the SCR cost analysis.

Table 4-5. EPNG Williams – RH 2PP 4FA – Engines - SCR - Costs

Parameter	**RECIP-1**	**RECIP-2**	**RECIP-5**
Engine Make / Model	Clark TLA6	Clark TLA6	Clark TLA10
Engine Size (hp)	2,000	2,000	3,400
Engine Size (MW)	1.49	1.49	2.54
NO_x Inlet (lb/MMBtu) [5]	5.04	4.05	4.63
Maximum Heat Input (MMBtu/hr)	15.11	15.11	23.20
Hours of Operation (hr/year) [1]	3,615	4,814	5,035
NO_x Removal Efficiency (%)	88%	85%	87%
CAPITAL COST (CC)			
SCR Capital Investment	$550,347	$550,347	$550,347
Preproduction Cost	$11,006.94	$11,007	$11,007
Inventory Capital	$4,863	$3,908	$6,859
Total Capital Cost $	**$566,217**	**$565,262**	**$568,213**
DIRECT OPERATING COST			
Operating Labor			
Operator Labor	$108,458	$144,428	$151,058

Parameter	RECIP-1	RECIP-2	RECIP-5
($60/hr, 1/2 actual operating hours)			
Supervision, 15% of Operator	$16,269	$21,664	$22,659
Maintenance			
Labor	$65,700	$65,700	$65,700
(1 hrs/shift @ $60/hr, 3 shifts/day, 365 days/yr)			
Material Cost	$65,700	$65,700	$65,700
Testing			
Quarterly Portable Analyzer Test ($600 each)	$2,400	$2,400	$2,400
Annual Reference Method Stack Test	$15,000	$15,000	$15,000
Utilities & Operating Expenses			
Electricity [3, 4]	$18,952	$21,613	$37,978
Mass Flow of Reagent (lb/hr) [6]	29.60	23.78	41.75
Mass Flow of 19% Ammonia (lb/hr)	155.77	125.18	219.72
Annual Cost of Ammonia ($/year) [2]	$275,387	$294,685	$541,003
Urea Consumption (gal/hr)	-	-	-
Urea Consumption (costs)	-	-	-
Catalyst Required (ft^3) [7]	79	79	134
Catalyst Cost ($/$ft^3$)	$249	$249	$249
Catalyst Cost ($)	$19,697	$19,697	$33,484
Future Worth Factor [8]	0.12	0.17	0.18
Annual Catalyst Replacement Cost	$2,432	$3,437	$6,159
Catalyst Replacement	-	-	-
Catalyst Installation	$608	$859	$1,540
Total Direct Operating Cost, $/yr	**$570,904**	**$635,486**	**$909,196**
INDIRECT OPERATING COST			
Overhead			
60% of operators, supervisors, maintenance labor, and material	$153,675.68	$178,495	$183,069.68
Administrative charges	$11,000	$11,000	$11,000
Property Taxes	$6,000	$6,000	$6,000
Insurance	$6,000	$6,000	$6,000
Capital Recovery Factor	0.1424	0.1424	0.1424
Remaining useful life of source	10	10	10
Interest Rate	7%	7%	7%
Capital Recovery Cost	$80,617	$80,481	$80,901
Total Indirect Operating Cost, $/yr	**$257,292**	**$281,976**	**$286,970**
TOTAL ANNUAL OPERATING COST - 2019 Dollars	**$828,196**	**$917,461**	**$1,196,167**
TOTAL ANNUAL OPERATING COST - 2028 Dollars [9]	**$1,035,246**	**$1,146,827**	**$1,495,209**
2028 Projected NO_x Emissions (tpy)	**148.40**	**170.40**	**205.16**
NO_x Removed (tpy)	**130.78**	**144.93**	**177.45**
2028 Cost of Control ($/ton NO_x removed)	**7,916**	**7,913**	**8,426**

Parameter	RECIP-1	RECIP-2	RECIP-5

[1] Per 2028 Projections

[2] Cost of 19% Ammonia: 0.49 $/lb

[3] Industrial electricity rate at Williams Compressor Station: 0.476 $/kW-hr

[4] Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equations 2.48 and 2.49, assuming the following values:

ΔP_{duct}: 3 in.

n_{total}: 2

$\Delta P_{catalyst}$: 1 in.

[5] Per 2019 Source Test.

[6] Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.35

[7] Assuming catalyst required is 1.5 m^3/MW

[8] Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equations 2.65 and 2.66 assuming the following:

	Recip-1	Recip-2	Recip-5
Interest Rate	7%	7%	7%
Catalyst Operating Life (hours)	24,000	24,000	24,000
SCR annual operating time (hours)	3,615	4,814	5,035

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

Time necessary to install controls: It is estimated that a total of 14 months is needed to install SCR control technology for each engine. This estimation is from EPNG Engineering Department 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. Engine efficiency would also be affected because an SCR system increases the engine backpressure.

In addition, it should be noted that in order to construct an SCR system, the building that houses the engines 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.

Remaining useful life of the source: It is assumed that the engines would continue operating for 10 years after 2028 to fully amortize the cost of controls.

4.2.3.5. Low-Emission Combustion (LEC) 2

LEC 2 would include adding high pressure fuel injection, turbocharger modifications, an aftercooler, and air-fuel ratio control.

Cost of control technology: For RECIP-1, a Clark TLA-6 engine, the total annualized cost of retrofitting the reciprocating engine was estimated to be $696,000 to remove 124 tpy of NO_x. This equates to a cost effectiveness of $5,594 per ton of NO_x removed. The projected 2028 cost is $6,993 per ton of NO_x removed. The post-control emission rate was estimated at 920 lb NO_x/MMCF.

For RECIP-2, a Clark TLA-6 engine, the total annualized cost of retrofitting the reciprocating engine was estimated to be $696,000 to remove 139 tpy of NO_x. This equates to a cost effectiveness of $5,027 per ton of NO_x removed. The projected 2028 cost is $6,283 per ton of NO_x removed. The post-control emission rate was estimated at 899 lb NO_x/MMCF.

For RECIP-5, a Clark TLA-10 engine, the total annualized cost of retrofitting the reciprocating engine was estimated to be $696,000 to remove 149 tpy of NO_x. This equates to a cost effectiveness of $4,689 per ton of NO_x removed. The projected 2028 cost is $5,861 per ton of NO_x removed. The post-control emission rate was estimated at 901 lb NO_x/MMCF.

See Table 4-3 for the cost analysis for LEC 1, LEC 2, and LEC 3.

Time necessary to install controls: It is estimated that a total of 14 months per engine is needed to install controls. This estimation is from EPNG Engineering Department and includes time for engineering, permitting, and installation.

Energy and non-air quality impacts: The High-Pressure Fuel Injection System requires electricity to operate. The generation of the electricity would involve fuel combustion, thereby increasing emissions. A new transformer may also be needed which could cost millions to install. The cost of a new transformer is not included in this analysis.

Remaining useful life of the source: It is assumed that the engines would continue operating for 10 years after 2028 to fully amortize the cost of controls.

4.2.3.6. Low-Emission Combustion (LEC) 1

Cost of control technology: For RECIP-1, a Clark TLA-6 engine, the total annualized cost of adding LEC 1 was estimated to be $356,000 to remove 85 tpy of NO_x. This equates to a cost effectiveness of $4,203 per ton of NO_x removed. The projected 2028 cost is $5,253 per ton of NO_x removed. The post-control emission rate was estimated at 2,454 lb NO_x/MMCF.

For RECIP-2, a Clark TLA-6 engine, the total annualized cost of adding LEC 1 was estimated to be $356,000 to remove 85 tpy of NO_x. This equates to a cost effectiveness of $4,161 per ton of NO_x removed. The projected 2028 cost is $5,201 per ton of NO_x removed. The post-control emission rate was estimated at 2,398 lb NO_x/MMCF.

For RECIP-5, a Clark TLA-10 engine, the total annualized cost of adding LEC 1 was estimated to be $356,000 to remove 54 tpy of NO_x. This equates to a cost effectiveness of $6,564 per ton of NO_x removed. The projected 2028 cost is $8,206 per ton of NO_x removed. The post-control emission rate was estimated at 2,402 lb NO_x/MMCF.

See Table 4-3 for the cost analysis for LEC 1, LEC 2, and LEC 3.

Time necessary to install controls It is estimated that a total of 14 months per engine is needed to install controls. This estimation is from EPNG Engineering Department and includes time for engineering, permitting, and installation.

Energy and non-air quality impacts: The High-Pressure Fuel Injection System requires electricity to operate. The generation of the electricity would most likely involve fuel combustion, thereby increasing emissions. A new transformer may also be needed which could cost millions to install. The cost of a new transformer is not included in the analysis.

Remaining useful life of the source: It is assumed that the engines would continue operating for 10 years after 2028 to fully amortize the cost of controls.

4.2.3.7. Air-Fuel Ratio Adjustment

Cost of control technology: For RECIP-1, a Clark TLA-6 engine, the total annualized cost of adding air-fuel ratio control was estimated to be $41,000 to remove 16 tpy of NO_x. This equates to a cost effectiveness of $2,529 per ton of NO_x removed. The projected 2028 cost is $3,161 per ton of NO_x removed. The post-control emission rate was estimated at 5,089 lb NO_x/MMCF. Note that although the cost of control is relatively low, the emissions that would be reduced from implementing this technology is minimal. As such, this control method is not effective.

The Clark TLA-6 engine (RECIP-2) and the Clark TLA-10 engine (RECIP-5) already achieve the 15 g NO_x/hp-hr emission rate that can be achieved by implementing this control, making the control infeasible for RECIP-2 and RECIP-5.

Time necessary to install controls: It is estimated that a total of 14 months is needed to install controls. This estimation is from EPNG Engineering Department and includes time for engineering, permitting, and installation.

Energy and non-air quality impacts: The automatic air-fuel ratio adjustment allows for more complete combustion, thereby extracting a larger amount of energy from fuel. This would result in reduced fuel consumption overall.

Remaining useful life of the source: It is assumed that the engines would continue operating for 10 years after 2028 to fully amortize the cost of controls.

5. SUMMARY & CONCLUSIONS

The cost of controls for the engines and turbine are summarized below in Table 5-1 and Table 5-2 respectively.

For the GE gas turbine and the Clark engines, with the exception of air-fuel controller with high energy ignition technology (which was previously described as ineffective due to the minimal amount of NO_x emissions captured), the cost for each technically feasible control technology is greater than $5,000 per ton of NO_x removed based on 2028 dollars. EPNG currently employs good combustion practices through routine inspection and maintenance of the turbine and engines and will continue with its current schedule and practices. Based on the energy, environmental, and economic impacts, it has been concluded that good combustion practice is the only feasible control option.

Table 5-1. EPNG Williams – RH 2PP 4FA – Engines - Cost of Controls

Unit	2028 Cost of Control for Technically Feasible Controls ($/ton)						
	Air-Fuel Controller with High Energy Ignition	LEC 1	LEC 2	LEC 3	Selective Catalytic Reduction (SCR)	Replacement Three Engines with Low Emission Unit	Replacement with Electric Motors
RECIP-1	3,161	5,253	6,993	7,798	7,916	10,795	33,903
RECIP-2	N/A	5,201	6,283	6,821	7,913	10,795	35,771
RECIP-5	N/A	8,206	5,861	5,754	8,426	10,795	47,595

Table 5-2. EPNG Williams – RH 2PP 4FA – Turbine - Cost of Controls

Unit	2028 Cost of Control for Technically Feasible Controls ($/ton)			
	Steam Injection	Water Injection	Liner Upgrade + Dry Low-NO_x/Simple Cycle	Selective Catalytic Reduction (SCR)
TURBINE-1	5,938	5,724	12,167	9,536

APPENDIX A: CONTROL COST ANALYSIS

Table A-1a. EPNG - Williams - RH 2PP - 4FA - Summary - Engines

Equipment				Baseline Operations		Baseline NOx Emissions			Technically Feasible Controls						
Type	Make & Model	Rating [1] (hp)	ADEQ Unit Description [2]	Fuel Usage [3] (MMcf/yr)	Hourly Usage (hrs/yr)	(tpy) [3]	(g/hp-hr) [4]	Four Factor Analysis Statutory Factor	Air-Fuel Controller with High Energy Ignition	High Pressure Fuel Injection (LEC 1)	High Pressure Fuel Injection + Turbocharger Reaero, Aftercooler, and Air-fuel Ratio Control (LEC 2)	High Pressure Fuel Injection + Turbocharger Reaero, Aftercooler, and Air-fuel Ratio Control + Pre-combustion Chambers, Electronic PCC Valves, and Auto-Balance System (LEC 3)	Selective Catalytic Reduction (SCR)	Replacement Three Engines with Low Emission Unit	Replacement with Electric Motors
Reciprocating Engine	Clark TLA-6	2,000	RECIP-1	51.956	3,615	148.40	16.84	Cost of Control ($/ton)	3,161	5,253	6,993	7,798	7,916	10,795	33,903
								Time Necessary for Installation (months)	14	14	14	14	14	18	18
								Energy and Non-Air Environmental Impacts	Reduced Engine Fuel Consumption	The High Pressure Fuel Injection System requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. Also, it may require a new transformer to be installed at the Williams station which could cost millions.	The High Pressure Fuel Injection System requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. Also, it may require a new transformer to be installed at the Williams station which could cost millions.	The High Pressure Fuel Injection System requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. Also, it may require a new transformer to be installed at the Williams station which could cost millions.	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. The SCR system requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. Also, it may require a new transformer to be installed at the Williams station which could cost millions. Transporting the chemical reagents would use natural resources for fuel and would have associated air quality impacts.	Overall higher engine rating may require additional fuel.	Requires new electric utility line and installation of sub-station possibly causing additional environmental problems.
								Remaining Useful Life of the Source	10	10	10	10	10	20	20
Reciprocating Engine	Clark TLA-6	2,000	RECIP-2	70.820	4,814	170.40	13.38	Cost of Control ($/ton)	-	5,201	6,283	6,821	7,913	See Summary for RECIP-1 as control is applicable to all three engines	35,771
								Time Necessary for Installation (months)	-	14	14	14	14		18
								Energy and Non-Air Environmental Impacts	-	See Summary for RECIP-1.	See Summary for RECIP-1.	See Summary for RECIP-1.	See Summary for RECIP-1.		See Summary for RECIP-1
								Remaining Useful Life of the Source	-	10	10	10	10		20
Reciprocating Engine	Clark TLA-10	3,400	RECIP-5	125.723	5,035	205.16	14.81	Cost of Control ($/ton)	-	8,206	5,861	5,754	8,426	See Summary for RECIP-1 as control is applicable to all three engines	47,595
								Time Necessary for Installation (months)	-	14	14	14	14		18
								Energy and Non-Air Environmental Impacts	-	See Summary for RECIP-1.	See Summary for RECIP-1.	See Summary for RECIP-1.	See Summary for RECIP-1.		See Summary for RECIP-1
								Remaining Useful Life of the Source	-	10	10	10	10		20

[1] Per July 2019 permit renewal application for Williams Compressor Station.
[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.
[4] Per Source Tests on February 20, 2019.

Table A-1b. EPNG - Williams - 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**	**Steam Injection**	**Water Injection**	**Liner Upgrade + Dry Low-NOx/Simple Cycle**	**Selective Catalytic Reduction (SCR)**
Gas Turbine Engine	GE M53222R	22,150	TURBINE-1	4,951	778.754	290.42	2.45	Cost of Control ($/ton)	5,938	5,724	12,167	9,536
								Time Necessary for Installation (months)	14	14	14	14
								Energy and Non-Air Environmental Impacts	Requires large amount of water to be transported to a remote area. Transporting the water would use natural resources for fuel and would have associated air quality impacts. Requires additional fuel gas supply of 16,000 scfh to vaporize the water.	Requires large amount of water to be transported to a remote area. Transporting the water would use natural resources for fuel and would have associated air quality 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	15	15

[1] Per July 2019 permit renewal application for Williams Compressor Station.
[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.
[4] Per Source Test on June 12, 2019.

Table A-2a. EPNG - Williams - RH 2PP - 4FA - Clark TLA-6 Engine (RECIP-1) - Control Review & Cost Analysis (Using 2028 Projected Emissions)

Technical Feasibility															
Parameter		Air-Fuel Controller with High Energy Ignition		High Pressure Fuel Injection (LEC 1)		High Pressure Fuel Injection + Turbocharger Reaero, Aftercooler, and Air-fuel Ratio Control (LEC 2)		High Pressure Fuel Injection + Turbocharger Reaero, Aftercooler, and Air-fuel Ratio Control + Pre-combustion Chambers, Electronic PCC Valves, and Auto-Balance System (LEC 3)		Selective Catalytic Reduction (SCR)		Replacement Three Engines with Low Emission Unit		Replacement with Electric Motors	
Value	Units	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference
Potential NOx Reduction															
NOx Reduction	%	11%	Calculated	52%	Calculated	82%	Calculated	97%	Calculated	88%	Calculated	See Table A-7		100%	Calculated
Rating	hp	2,000	[1]	2,000	[1]	2,000	[1]	2,000	[1]	2,000	[1]			2,000	[1]
Inlet NOx	g/hp-hr	16.84	[2]	16.84	[2]	16.84	[2]	16.84	[2]	16.84	[2]			16.84	[2]
Outlet NOx	g/hp-hr	15.00	[10]	8.00	[10]	3.00	[10]	0.50	[10]	2.00	[21]			0.00	Due to Replacement
Inlet NOx	tpy	148.40	[2]	148.40	[2]	148.40	[2]	148.40	[2]	148.40	[2]			148.40	[2]
Outlet NOx	tpy	132.19	Calculated	63.76	Calculated	23.91	Calculated	3.99	Calculated	17.63	Calculated			0.00	Calculated
NOx Reduced	tpy	16.22	Calculated	84.64	Calculated	124.49	Calculated	144.42	Calculated	130.78	Calculated			148.40	Calculated
Capital Implementation Costs															
Total Cost	$	$155,000	[10], [11]	$1,250,000	[10], [11]	$2,500,000	[10], [11]	$3,250,000	[10], [11]	See Table A-4		See Table A-7		$10,853,533	[21]
Cost Obtained from Vendor Quote?	Yes / No	Yes	[12]	Yes	[12]	Yes	[12]	Yes	[12]					Yes	[12]
Capital Recovery Factor	%	14.24%	[3]	14.24%	[3]	14.24%	[3]	14.24%	[3]					9.44%	[3]
Annualized Cost	$/yr	$22,069	Calculated	$177,972	Calculated	$355,944	Calculated	$462,727	Calculated					$1,024,497	Calculated
Admin, Taxes, Insurance	$/yr	$6,200	[4]	$50,000	[4]	$100,000	[4]	$130,000	[4]					$434,141	[4]
Fixed Operating Cost	$/yr	$12,742	[5], [6]	$127,770	[5], [6]	$240,539	[5], [6]	$308,201	[5], [6]					$2,566,489	[23]
Variable Operating Cost - Reagent	$/yr	-	-	-	-	-	-	-	-					-	-
Variable Operating Cost - Catalyst	$/yr	-	-	-	-	-	-	-	-					-	-
Total Annual Cost	$/yr	$41,011	Calculated	$355,741	Calculated	$696,483	Calculated	$900,928	Calculated	$828,196	Calculated			$4,025,127	Calculated
Cost of Control (Statutory Factor 1)															
2019 Cost of Control	$/ton removed	$2,529	Calculated	$4,203	Calculated	$5,594	Calculated	$6,238	Calculated	$6,333	Calculated	$8,636	Calculated	$27,123	Calculated
2028 Cost of Control	$/ton removed	$3,161	[25]	$5,253	[25]	$6,993	[25]	$7,798	[25]	$7,916	[25]	$10,795	[25]	$33,903	[25]
Post-Control Emission Rate	lb/MMCF	5,089	Calculated	2,454	Calculated	920	Calculated	153	Calculated	678	Calculated	432	Calculated	0	Calculated
Averaging Period		30-day rolling	Proposed	30-day rolling	Proposed	30-day rolling	Proposed	30-day rolling	Proposed	30-day rolling	Proposed	30-day rolling	Proposed	-	-
Time Necessary for Installation (Statutory Factor 2)															
Modification/ Replacement time	months	8	[24]	8	[24]	8	[24]	8	[24]	8	[24]	12	[24]	12	[24]
Permitting	months	4	Estimated	4	Estimated	4	Estimated	4	Estimated	4	Estimated	4	Estimated	4	Estimated
Engineering	months	2	Estimated	2	Estimated	2	Estimated	2	Estimated	2	Estimated	2	Estimated	2	Estimated
Total Time Necessary for Compliance	months	14	Calculated	14	Calculated	14	Calculated	14	Calculated	14	Calculated	18	Calculated	18	Calculated
Energy and Non-Air Environmental Impacts (Statutory Factor 3)															
Energy and Non-Air Environmental Impacts		Reduced Engine Fuel Consumption	[17]	The High Pressure Fuel Injection System requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. Also, it may require a new transformer to be installed at the Williams station which could cost millions.	[18]	The High Pressure Fuel Injection System requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. Also, it may require a new transformer to be installed at the Williams station which could cost millions.	[18]	The High Pressure Fuel Injection System requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. Also, it may require a new transformer to be installed at the Williams station which could cost millions.	[18]	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. The SCR system requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. Also, it may require a new transformer to be installed at the Williams station which could cost millions. Transporting the chemical reagents would use natural resources for fuel and would have associated air quality impacts.	[18], [19]	Overall higher engine rating may require additional fuel.	Process Knowledge	Requires new electric utility line and installation of sub-station possibly causing additional environmental problems.	Process Knowledge
Remaining Useful Life of the Source (Statutory Factor 4)															
Remaining Useful Life	Years	10	Estimated	10	Estimated	10	Estimated	10	Estimated	10	Estimated	20	Estimated	20	Estimated

Table A-2a. EPNG - Williams - RH 2PP - 4FA - Clark TLA-6 Engine (RECIP-1) - Control Review & Cost Analysis (Using 2028 Projected Emissions)

Technical Feasibility															
Parameter		Air-Fuel Controller with High Energy Ignition		High Pressure Fuel Injection (LEC 1)		High Pressure Fuel Injection + Turbocharger Reaero, Aftercooler, and Air-fuel Ratio Control (LEC 2)		High Pressure Fuel Injection + Turbocharger Reaero, Aftercooler, and Air-fuel Ratio Control + Pre-combustion Chambers, Electronic PCC Valves, and Auto-Balance System (LEC 3)		Selective Catalytic Reduction (SCR)		Replacement Three Engines with Low Emission Unit		Replacement with Electric Motors	
Value	Units	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference

[1] Data from July 2019 renewal application.
[2] 2028 Projected Emissions per ADEQ Emissions Projection Methodology
[3] Capital Recovery factor (CRF) calculated as follows

Interest Rate	7%
Remaining useful life of source	10
Capital Recovery Factor	14.24%

For installation of new engines (electrical or low-emitting):

Interest Rate	7%
Remaining useful life of source	20
Capital Recovery Factor	9.44%

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

[4] 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
[5] Fixed operating cost includes operating labor, maintenance, testing, and electricity estimates obtained from multiple vendor quotes found in two recent RACT analyses prepared for Colorado Interstate Gas Company compressor stations
[6] 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	-

[7] Urea consumption based on average of urea consumption in multiple vendor quotes for two recent RACT analyses prepared for Colorado Interstate Gas Company compressor stations
Cost of Urea 0.78 $/gal
[8] Capital cost data interpolated from multiple vendor quotes in two recent RACT analyses prepared for Colorado Interstate Gas Company compressor stations
[9] Cost of catalyst obtained from the following equations found in vendor quotes per two recent RACT analyses prepared for Colorado Interstate Gas Company compressor stations
Catalyst Replacement = 0.33 x Total Capital Cost
Catalyst Installation = 0.25 x Catalyst Replacement
[10] Per information received from Weiwen Daly, EPNG, on August 1, 2019.
[11] 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."*
[12] 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."*
[13] Per EPA archived document "Stationary Reciprocating Internal Combustion Engines, Updated Information on NOx Emissions and Control Techniques".
[14] Per EPA "Alternative Control Techniques Document–NOx Emissions from Stationary Reciprocating Internal Combustion Engines."
[15] Per academic literature: "Using Exhaust Gas Recirculation in Internal Combustion Engines: A Review"
[16] Per extensive literature review, this technology appears to mainly be used on industrial-sized boiler.
[17] Per PRO Fact Sheet No. 104, "Install Automated Air/Fuel Ratio Controls".
[18] Per email received from Weiwen Daly, EPNG on October 17, 2019.
[19] Per "Title V Significant Modification to Request Alternative NOx RACT Emission Limit" for Texas Eastern Transmission, L.P. Lambertville, New Jersey submitted November 2017.
[20] Per EPA "Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance Final TSD"
[21] Per email received from Weiwen Daly, EPNG on September 25, 2019. Cost includes cost of new motor ($1,469/hp), new electric utility line ($3,500,000 divided by 3 engines), and new substation ($20,246,600 divided by 3 engines).
[22] Per phone call with Weiwen Daly, EPNG on September 25, 2019.
[23] Industrial electricity rate at Williams Compressor Station: 0.476 $/kW-hr
[24] Per estimate received from Jonathan Goss, EPNG on 10/3/2019. Modifications will require 8 months; replacements will require 12 months.
[25] Adjusted current price to 2028 projected price using an inflation rate of: 25 %

Table A-2b. EPNG - Williams - RH 2PP - 4FA - Clark TLA-6 Engine (RECIP-2) - Control Review & Cost Analysis (Using 2028 Projected Emissions)

Technical Feasibility													
Parameter		**High Pressure Fuel Injection (LEC 1)**		**High Pressure Fuel Injection + Turbocharger Reaero, Aftercooler, and Air-fuel Ratio Control (LEC 2)**		**High Pressure Fuel Injection + Turbocharger Reaero, Aftercooler, and Air-fuel Ratio Control + Pre-combustion Chambers, Electronic PCC Valves, and Auto-Balance System (LEC 3)**		**Selective Catalytic Reduction (SCR)**		**Replacement Three Engines with Low Emission Unit**		**Replacement with Electric Motors**	
Value	**Units**	**Value**	**Reference**	**Value**	**Reference**	**Value**	**Reference**	**Value**	**Reference**	**Value**	**Reference**	**Value**	**Reference**
Potential NOx Reduction													
NOx Reduction	%	40%	Calculated	78%	Calculated	96%	Calculated	85%	Calculated			100%	Calculated
Rating	hp	2,000	[1]	2,000	[1]	2,000	[1]	2,000	[1]			2,000	[1]
Inlet NOx	g/hp-hr	13.38	[2]	13.38	[2]	13.38	[2]	13.38	[2]			13.38	[2]
Outlet NOx	g/hp-hr	8.00	[10]	3.00	[10]	0.50	[10]	2.00	[21]	See Table A-7		0.00	Due to Replacement
Inlet NOx	tpy	170.40	[2]	170.40	[2]	170.40	[2]	170.40	[2]			170.40	[2]
Outlet NOx	tpy	84.91	Calculated	31.84	Calculated	5.31	Calculated	25.47	Calculated			0.00	Calculated
NOx Reduced	tpy	85.49	Calculated	138.56	Calculated	165.09	Calculated	144.93	Calculated			170.40	Calculated
Capital Implementation Costs													
Total Cost	$	$1,250,000	[10], [11]	$2,500,000	[10], [11]	$3,250,000	[10], [11]					$10,853,533	[21]
Cost Obtained from Vendor Quote?	Yes / No	Yes	[12]	Yes	[12]	Yes	[12]					Yes	[12]
Capital Recovery Factor	%	14.24%	[3]	14.24%	[3]	14.24%	[3]					9.44%	[3]
Annualized Cost	$/yr	$177,972	Calculated	$355,944	Calculated	$462,727	Calculated	See Table A-4				$1,024,497	Calculated
Admin, Taxes, Insurance	$/yr	$50,000	[4]	$100,000	[4]	$130,000	[4]			See Table A-7		$434,141	[4]
Fixed Operating Cost	$/yr	$127,770	[5], [6]	$240,539	[5], [6]	$308,201	[5], [6]					$3,417,666	[23]
Variable Operating Cost - Reagent	$/yr	-	-	-	-	-	-					-	-
Variable Operating Cost - Catalyst	$/yr	-	-	-	-	-	-					-	-
Total Annual Cost	$/yr	$355,741	Calculated	$696,483	Calculated	$900,928	Calculated	$917,461	Calculated			$4,876,304	Calculated
Cost of Control (Statutory Factor 1)													
2019 Cost of Control	$/ton removed	$4,161	Calculated	$5,027	Calculated	$5,457	Calculated	$6,330	Calculated	$8,636	Calculated	$28,617	Calculated
2028 Cost of Control	$/ton removed	$5,201	[25]	$6,283	[25]	$6,821	[25]	$7,913	[25]	$10,795	[25]	$35,771	[25]
Post-Control Emission Rate	lb/MMCF	2,398	Calculated	899	Calculated	150	Calculated	719	Calculated	432	Calculated	0	Calculated
Averaging Period		30-day rolling	Proposed	30-day rolling	Proposed	30-day rolling	Proposed	30-day rolling	Proposed	30-day rolling	Proposed	-	-
Time Necessary for Installation (Statutory Factor 2)													
Modification/ Replacement time	months	8	[24]	8	[24]	8	[24]	8	[24]	12	[24]	12	[24]
Permitting	months	4	Estimated	4	Estimated	4	Estimated	4	Estimated	4	Estimated	4	Estimated
Engineering	months	2	Estimated	2	Estimated	2	Estimated	2	Estimated	2	Estimated	2	Estimated
Total Time Necessary for Compliance	months	14	Calculated	14	Calculated	14	Calculated	14	Calculated	18	Calculated	18	Calculated
Energy and Non-Air Environmental Impacts (Statutory Factor 3)													
Energy and Non-Air Environmental Impacts		The High Pressure Fuel Injection System requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. Also, it may require a new transformer to be installed at the Williams station which could cost million	[18]	The High Pressure Fuel Injection System requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. Also, it may require a new transformer to be installed at the Williams station which could cost million	[18]	The High Pressure Fuel Injection System requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. Also, it may require a new transformer to be installed at the Williams station which could cost million	[18]	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. The SCR system requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. Also, it may require a new transformer to be installed at the Williams station which could cost millions. Transporting the chemical reagents would use natural resources for fuel and would have associated air quality impacts.	[18], [19]	Overall higher engine rating may require additional fuel.	Process Knowledge	Requires new electric utility line and installation of sub-station possibly causing additional environmental problems.	Process Knowledge
Remaining Useful Life of the Source (Statutory Factor 4)													
Remaining Useful Life	Years	10	Estimated	10	Estimated	10	Estimated	10	Estimated	20	Estimated	20	Estimated

Table A-2b. EPNG - Williams - RH 2PP - 4FA - Clark TLA-6 Engine (RECIP-2) - Control Review & Cost Analysis (Using 2028 Projected Emissions)

Technical Feasibility														
Parameter		High Pressure Fuel Injection (LEC 1)		High Pressure Fuel Injection + Turbocharger Reaero, Aftercooler, and Air-fuel Ratio Control (LEC 2)		High Pressure Fuel Injection + Turbocharger Reaero, Aftercooler, and Air-fuel Ratio Control + Pre-combustion Chambers, Electronic PCC Valves, and Auto-Balance System (LEC 3)		Selective Catalytic Reduction (SCR)		Replacement Three Engines with Low Emission Unit		Replacement with Electric Motors		
Value	Units	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference	

[1] Data from July 2019 renewal application.
[2] 2028 Projected Emissions per ADEQ Emissions Projection Methodology
[3] Capital Recovery factor (CRF) calculated as follows

Interest Rate	7%
Remaining useful life of source	10
Capital Recovery Factor	14.24%
For installation of new engines (electrical or low-emitting):	
Interest Rate	7%
Remaining useful life of source	20
Capital Recovery Factor	9.44%

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"

[4] 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
[5] Fixed operating cost includes operating labor, maintenance, testing, and electricity estimates obtained from multiple vendor quotes found in two recent RACT analyses prepared for Colorado Interstate Gas Company compressor station
[6] 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	-

[7] Urea consumption based on average of urea consumption in multiple vendor quotes for two recent RACT analyses prepared for Colorado Interstate Gas Company compressor stations
Cost of Urea 0.78 $/gal
[8] Capital cost data interpolated from multiple vendor quotes in two recent RACT analyses prepared for Colorado Interstate Gas Company compressor stations
[9] Cost of catalyst obtained from the following equations found in vendor quotes per two recent RACT analyses prepared for Colorado Interstate Gas Company compressor stations
Catalyst Replacement = 0.33 x Total Capital Cost
Catalyst Installation = 0.25 x Catalyst Replacement
[10] Per information received from Weiwen Daly, EPNG, on August 1, 2019.
[11] 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."*
[12] 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."*
[13] Per EPA archived document "Stationary Reciprocating Internal Combustion Engines, Updated Information on NOx Emissions and Control Techniques".
[14] Per EPA "Alternative Control Techniques Document–NOx Emissions from Stationary Reciprocating Internal Combustion Engines."
[15] Per academic literature: "Using Exhaust Gas Recirculation in Internal Combustion Engines: A Review"
[16] Per extensive literature review, this technology appears to mainly be used on industrial-sized boiler.
[17] Per PRO Fact Sheet No. 104, "Install Automated Air/Fuel Ratio Controls".
[18] Per email received from Weiwen Daly, EPNG on October 17, 2019.
[19] Per "Title V Significant Modification to Request Alternative NOx RACT Emission Limit" for Texas Eastern Transmission, L.P. Lambertville, New Jersey submitted November 2017.
[20] Per EPA "Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance Final TSD"
[21] Per email received from Weiwen Daly, EPNG on September 25, 2019. Cost includes cost of new motor ($1,469/hp), new electric utility line ($3,500,000 divided by 3 engines), and new substation ($20,246,600 divided by 3 engines).
[22] Per phone call with Weiwen Daly, EPNG on September 25, 2019.
[23] Industrial electricity rate at Williams Compressor Station: 0.476 $/kW-hr
[24] Per estimate received from Jonathan Goss, EPNG on 10/3/2019. Modifications will require 8 months; replacements will require 12 months.
[25] Adjusted current price to 2028 projected price using an inflation rate of: 25 %

Table A-2c. EPNG - Williams - RH 2PP - 4FA - Clark TLA-10 Engine (RECIP-5) - Control Review & Cost Analysis (Using 2028 Projected Emissions)

Technical Feasibility													
Parameter		High Pressure Fuel Injection (LEC 1)		High Pressure Fuel Injection + Turbocharger Reaero, Aftercooler, and Air-fuel Ratio Control (LEC 2)		High Pressure Fuel Injection + Turbocharger Reaero, Aftercooler, and Air-fuel Ratio Control + Pre-combustion Chambers, Electronic PCC Valves, and Auto-Balance System (LEC 3)		Selective Catalytic Reduction (SCR)		Replacement Three Engines with Low Emission Unit		Replacement with Electric Motors	
Value	Units	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference
Potential NOx Reduction													
NOx Reduction	%	46%	Calculated	80%	Calculated	97%	Calculated	86%	Calculated	See Table A-7		100%	Calculated
Rating	hp	3,400	[1]	3,400	[1]	3,400	[1]	3,400	[1]			3,400	[1]
Inlet NOx	g/hp-hr	14.81	[2]	14.81	[2]	14.81	[2]	14.81	[2]			14.81	[2]
Outlet NOx	g/hp-hr	8.00	[10]	3.00	[10]	0.50	[10]	2.00	[21]			0.00	Due to Replacement
Inlet NOx	tpy	205.16	[2]	205.16	[2]	205.16	[2]	205.16	[2]			205.16	[2]
Outlet NOx	tpy	150.97	Calculated	56.61	Calculated	9.44	Calculated	27.71	Calculated			0.00	Calculated
NOx Reduced	tpy	54.19	Calculated	148.55	Calculated	195.73	Calculated	177.45	Calculated			205.16	Calculated
Capital Implementation Costs													
Total Cost	$	$1,250,000	[10], [11]	$2,500,000	[10], [11]	$3,250,000	[10], [11]	See Table A-4		See Table A-7		$12,910,133	[21]
Cost Obtained from Vendor Quote?	Yes / No	Yes	[12]	Yes	[12]	Yes	[12]					Yes	[12]
Capital Recovery Factor	%	14.24%	[3]	14.24%	[3]	14.24%	[3]					9.44%	[3]
Annualized Cost	$/yr	$177,972	Calculated	$355,944	Calculated	$462,727	Calculated					$1,218,625	Calculated
Admin, Taxes, Insurance	$/yr	$50,000	[4]	$100,000	[4]	$130,000	[4]					$516,405	[4]
Fixed Operating Cost	$/yr	$127,770	[5], [6]	$240,539	[5], [6]	$308,201	[5], [6]					$6,076,744	[23]
Variable Operating Cost - Reagent	$/yr	-	-	-	-	-	-					-	-
Variable Operating Cost - Catalyst	$/yr	-	-	-	-	-	-					-	-
Total Annual Cost	$/yr	$355,741	Calculated	$696,483	Calculated	$900,928	Calculated	$1,196,167	Calculated			$7,811,775	Calculated
Cost of Control (Statutory Factor 1)													
2019 Cost of Control	$/ton removed	$6,564	Calculated	$4,689	Calculated	$4,603	Calculated	$6,741	Calculated	$8,636	Calculated	$38,076	Calculated
2028 Cost of Control	$/ton removed	$8,206	[25]	$5,861	[25]	$5,754	[25]	$8,426	[25]	$10,795	[25]	$47,595	[25]
Post-Control Emission Rate	lb/MMCF	2,402	Calculated	901	Calculated	150	Calculated	441	Calculated	432	Calculated	0	Calculated
Averaging Period		30-day rolling	Proposed	30-day rolling	Proposed	30-day rolling	Proposed	30-day rolling	Proposed	30-day rolling	Proposed	-	-
Time Necessary for Installation (Statutory Factor 2)													
Modification/ Replacement time	months	8	[24]	8	[24]	8	[24]	8	[24]	12	[24]	12	[24]
Permitting	months	4	Estimated	4	Estimated	4	Estimated	4	Estimated	4	Estimated	4	Estimated
Engineering	months	2	Estimated	2	Estimated	2	Estimated	2	Estimated	2	Estimated	2	Estimated
Total Time Necessary for Compliance	months	14	Calculated	14	Calculated	14	Calculated	14	Calculated	18	Calculated	18	Calculated
Energy and Non-Air Environmental Impacts (Statutory Factor 3)													
Energy and Non-Air Environmental Impacts		The High Pressure Fuel Injection System requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. Also, it may require a new transformer to be installed at the Williams station which could cost million	[18]	The High Pressure Fuel Injection System requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. Also, it may require a new transformer to be installed at the Williams station which could cost million	[18]	The High Pressure Fuel Injection System requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. Also, it may require a new transformer to be installed at the Williams station which could cost million	[18]	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. The SCR system requires electricity to operate. The generation of the electricity will most likely involve fuel combustion, which	[18], [19]	Overall higher engine rating may require additional fuel.	Process Knowledge	Requires new electric utility line and installation of sub-station possibly causing additional environmental problems.	Process Knowledge
Remaining Useful Life of the Source (Statutory Factor 4)													
Remaining Useful Life	Years	10	Estimated	10	Estimated	10	Estimated	10	Estimated	20	Estimated	20	Estimated

Table A-2c. EPNG - Williams - RH 2PP - 4FA - Clark TLA-10 Engine (RECIP-5) - Control Review & Cost Analysis (Using 2028 Projected Emissions)

Technical Feasibility													
Parameter		High Pressure Fuel Injection (LEC 1)		High Pressure Fuel Injection + Turbocharger Reaero, Aftercooler, and Air-fuel Ratio Control (LEC 2)		High Pressure Fuel Injection + Turbocharger Reaero, Aftercooler, and Air-fuel Ratio Control + Pre-combustion Chambers, Electronic PCC Valves, and Auto-Balance System (LEC 3)		Selective Catalytic Reduction (SCR)		Replacement Three Engines with Low Emission Unit		Replacement with Electric Motors	
Value	Units	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference	Value	Reference

[1] Data from July 2019 renewal application.
[2] 2028 Projected Emissions per ADEQ Emissions Projection Methodology
[3] Capital Recovery factor (CRF) calculated as follows

Interest Rate	7%
Remaining useful life of source	10
Capital Recovery Factor	14.24%
For installation of new engines (electrical or low-emitting):	
Interest Rate	7%
Remaining useful life of source	20
Capital Recovery Factor	9.44%

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"

[4] 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
[5] Fixed operating cost includes operating labor, maintenance, testing, and electricity estimates obtained from multiple vendor quotes found in two recent RACT analyses prepared for Colorado Interstate Gas Company compressor station
[6] 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	-

[7] Urea consumption based on average of urea consumption in multiple vendor quotes for two recent RACT analyses prepared for Colorado Interstate Gas Company compressor stations
Cost of Urea 0.78 $/gal
[8] Capital cost data interpolated from multiple vendor quotes in two recent RACT analyses prepared for Colorado Interstate Gas Company compressor stations
[9] Cost of catalyst obtained from the following equations found in vendor quotes per two recent RACT analyses prepared for Colorado Interstate Gas Company compressor stations
Catalyst Replacement = 0.33 x Total Capital Cost
Catalyst Installation = 0.25 x Catalyst Replacement
[10] Per information received from Weiwen Daly, EPNG, on August 1, 2019.
[11] 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."*
[12] 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."*
[13] Per EPA archived document "Stationary Reciprocating Internal Combustion Engines, Updated Information on NOx Emissions and Control Techniques".
[14] Per EPA "Alternative Control Techniques Document–NOx Emissions from Stationary Reciprocating Internal Combustion Engines."
[15] Per academic literature: "Using Exhaust Gas Recirculation in Internal Combustion Engines: A Review"
[16] Per extensive literature review, this technology appears to mainly be used on industrial-sized boiler.
[17] Per PRO Fact Sheet No. 104, "Install Automated Air/Fuel Ratio Controls".
[18] Per email received from Weiwen Daly, EPNG on October 17, 2019.
[19] Per "Title V Significant Modification to Request Alternative NOx RACT Emission Limit" for Texas Eastern Transmission, L.P. Lambertville, New Jersey submitted November 2017.
[20] Per EPA "Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance Final TSD"
[21] Per email received from Weiwen Daly, EPNG on September 25, 2019. Cost includes cost of new motor ($1,469/hp), new electric utility line ($3,500,000 divided by 3 engines), and new substation ($20,246,600 divided by 3 engines).
[22] Per phone call with Weiwen Daly, EPNG on September 25, 2019.
[23] Industrial electricity rate at Williams Compressor Station: 0.476 $/kW-hr
[24] Per estimate received from Jonathan Goss, EPNG on 10/3/2019. Modifications will require 8 months; replacements will require 12 months.
[25] Adjusted current price to 2028 projected price using an inflation rate of: 25 %

Table A-3. EPNG - Williams - RH 2PP - 4FA - GE M5322R Turbine (TURBINE-1) - Control Review & Cost Analysis (Using 2028 Projected Emissions)

Technical Feasibility													
Parameter		**Steam Injection**		**Water Injection**		**Liner Upgrade + Dry Low-NOx/Simple Cycle**		**Selective Catalytic Reduction (SCR)**		**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		Yes		Yes		No		No	
If not, please explain										SCNR is only effective in a relatively high, narrow temperature range (greater than 1600 °F). The exhaust from TURBINE-1 is less than 1,000 °F.	[17], [21]	The operating temperature range for this technology is limited to 300 to 700 °F. The exhaust from a simple-cycle turbine is greater than 900 deg F making this technology technically infeasible for simple-cycle operation.	[16], [21]
If Control Technology is Technically Feasible, Complete the Following													
Potential NOx Reduction													
NOx Reduction	%	75%	[19]	75%	[19]	79%	[11]	See Table A-5					
Rating	MW	16.52	[1]	16.52	[1]	16.52	[1]						
Operating Hours	hr/yr	4,951	2028 Projections	4,951	2028 Projections	4,951	2028 Projections						
Inlet NOx	tpy	290.42	Calculated	290.42	Calculated	290.42	Calculated						
Outlet NOx	tpy	71.75	Calculated	71.75	Calculated	59.79	Calculated						
NOx Reduced	tpy	219	Calculated	219	Calculated	231	Calculated						
Capital Implementation Costs													
Unit Cost	$/kW	223.71	Calculated	208.57	Calculated	338.43	Calculated	See Table A-5					
Total Cost	$	$3,695,000	[13], [19], [23]	$3,445,000	[13], [19], [23]	$5,590,000	[12], [13]						
Cost Obtained from Vendor Quote?	Yes / No	Yes	[14], [19]	Yes	[14], [19]	No	[12], [14]						
Capital Recovery Factor	%	10.98%	[2]	10.98%	[2]	10.98%	[2]						
Annualized Cost	$/yr	$405,691	Calculated	$378,242	Calculated	$613,752	Calculated						
Admin, Taxes, Insurance	$/yr	$147,800	[3]	$137,800	[3]	$223,600	[3]						
Fixed Operating Cost	$/yr	$43,101	[6], [5]	$43,101	[6], [5]	$184,717	[5], [6]						
Variable Operating Cost - Fuel	$/yr	$281,030	[5], [6], [7]	$281,030	[5], [6], [7]	$1,222,715	[5], [6], [22]						
Variable Operating Cost - Water	$/yr	$161,108	[5], [6], [7]	$161,108	[5], [6], [7]	-	-						
Total Annual Cost	$/yr	$1,038,730	Calculated	$1,001,282	Calculated	$2,244,784	Calculated						
Cost of Control (Statutory Factor 1)													
2019 Cost of Control	$/ton removed	$4,750	Calculated	$4,579	Calculated	$9,733	Calculated	$7,629	Calculated				
2028 Cost of Control	$/ton removed	$5,938	[24]	$5,724	[24]	$12,167	[24]	$9,536	[24]				
Post-Control Emission Rate	lb/MMCF	184.27	Calculated	184.27	Calculated	153.56	Calculated	205.33	Calculated				
Averaging Period		30-day rolling	Proposed	30-day rolling	Proposed	30-day rolling	Proposed	30-day rolling	Proposed				
Time Necessary for Installation (Statutory Factor 2)													
Modification time	months	8	[20]	8	[20]	8	[20]	8	[20]				
Permitting	months	4	Estimated	4	Estimated	4	Estimated	4	Estimated				
Engineering	months	2	Estimated	2	Estimated	2	Estimated	2	Estimated				
Total Time Necessary for Compliance	months	14	Estimated	14	Estimated	14	Estimated	14	Estimated				
Energy and Non-Air Environmental Impacts (Statutory Factor 3)													

Table A-3. EPNG - Williams - RH 2PP - 4FA - GE M5322R Turbine (TURBINE-1) - Control Review & Cost Analysis (Using 2028 Projected Emissions)

Technical Feasibility													
Parameter		**Steam Injection**		**Water Injection**		**Liner Upgrade + Dry Low-NOx/Simple Cycle**		**Selective Catalytic Reduction (SCR)**		**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**
Energy and Non-Air Environmental Impacts		Requires large amount of water to be transported to a remote area. Transporting the water would use natural resources for fuel and would have associated air quality impacts. Requires additional fuel gas supply of 16,000 scfh to vaporize the water.	[18]	Requires large amount of water to be transported to a remote area. Transporting the water would use natural resources for fuel and would have associated air quality impacts.	[18]	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.	[15]				
Remaining Useful Life of the Source (Statutory Factor 4)													
Remaining Useful Life	Years	15	Estimated	15	Estimated	15	Estimated	15	Estimated				

[1] Data from July 2019 renewal application.

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

Interest Rate	7%
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] Fixed operating cost escalated from NESCAUM, "Status Report on NOx for Industrial Boilers, Gas Turbines, IC Engines, and Cement Kilns; Control Technologies and Cost Effectiveness", December 2000, pg IV-47. Cost was escalated using the Chemical Engineering Plant Cost Index

[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	-

Table A-3. EPNG - Williams - RH 2PP - 4FA - GE M5322R Turbine (TURBINE-1) - Control Review & Cost Analysis (Using 2028 Projected Emissions)

Technical Feasibility														
Parameter		**Steam Injection**		**Water Injection**		**Liner Upgrade + Dry Low-NOx/Simple Cycle**		**Selective Catalytic Reduction (SCR)**		**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**	

[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. Cost includes fuel cost, pumping electricity cost, and plant overhead cost.

Fuel cost	2.5	$/MMBTU	=	2.55 $/MSCF
[7] Requires fuel supply of	16000	SCFH	per vendor quote received on October 21, 2019.	
and fuel penalty of	3.5	%	due to performance loss	
and water supply of	30	gpm	per vendor quote received on October 21, 2019.	

Cost of water includes: water cost, water treatment cost, water treatment labor cost, and water disposal cost. Actual water cost was obtained from EPNG Williams September, October, and November 2019 water bill. Water treatment cost, water treatment labor cost, and water disposal labor cost per Onsite Sycom Energy Corporation, "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines", Contract No. DE-FC02-97CHIO877, November 5, 1999.

Water cost per September, October, and November 2019 water bill: 8.09 $/1,000 gal

[8] During 1st Planning Period, EPA assumed that 1.05 moles of NH3 were required per mole of NOx reduced.

[9] Cost of Ammonia 551 $/ton per NESCAUM, "Status Report on NOx for Industrial Boilers, Gas Turbines, IC Engines, and Cement Kilns; Control Technologies and Cost Effectiveness", December 2000

[10] During 1st Planning Period, EPA assumed that the cost was $10,000 per m^3 of catalyst, 1.5 m^3 catalyst per MW, and replacement occurred every 3 years.

[11] Target NOx outlet of 35 ppm per vendor quote. Inlet NOx input obtained from 2019 emissions summary.

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

[13] 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."

[14] 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."

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

[16] 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

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

[18] Per email received from Weiwen Daly, EPNG on October 17, 2019.

[19] Per GE quote received from Jonathan Goss, EPNG on October 3, 2019 and October 21, 2019. NOx reduction for water/steam injection was calculated based on an outlet concentration of 42 ppmvd @ 15% O_2 and an inlet concentration of 170 ppmvd @ 15% O_2 obtained from 2019 emissions summary.

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

[21] Exhaust temperature per 2018 and 2019 Emissions Summary

[22] 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.

[23] Capital cost includes the cost of installing a water purification system. Price is conservatively scaled up from a 20 gpm model per: https://www.samcotech.com/how-much-does-a-water-demineralization-system-cost-for-your-plant/

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

Table A-4. EPNG - Williams - RH 2PP - 4FA - SCR for Engines - Costs

Name of Operator			**El Paso Natural Gas**	**El Paso Natural Gas**	**El Paso Natural Gas**
Location			Williams	Williams	Williams
Engine Make			Clark	Clark	Clark
Engine Model			TLA6	TLA6	TLA10
Engine Type			2SLB	2SLB	2SLB
Date of Quote			August-19	August-19	August-19
Vendor Providing Quote			N/A	N/A	N/A
ADEQ Unit Description			RECIP-1	RECIP-2	RECIP-5
Engine Size (hp)			2,000	2,000	3,400
Engine Size (MW)			1.49	1.49	2.54
NOx Inlet (lb/MMBtu) [6]			5.04	4.05	4.63
Maximum Heat Input (MMBtu/hr)			15.11	15.11	23.20
Hours of Operation (hr/year) [2]			3,615	4,814	5,035
NOx Removal Efficiency (%)			88%	85%	86%
CAPITAL COST (CC)					
SCR Capital Investment			$550,347	$550,347	$550,347
Preproduction Cost	0.02	x SCR Capital	$11,006.94	$11,007	$11,007
Inventory Capital	14	days NH_3 supply	$4,863	$3,908	$6,859
Total Capital Cost $			**$566,217**	**$565,262**	**$568,213**
DIRECT OPERATING COST					
Operating Labor					
Operator Labor					
(8 hr/mn day @ $60/hr, 9 mn day/year)					
Operator Labor			$108,458	$144,428	$151,058
($60/hr, 1/2 actual operating hours)					
Supervision, 15% of Operator	0.15	x Operator	$16,269	$21,664	$22,659
Maintenance					
Labor			$65,700	$65,700	$65,700
(1 hrs/shift @ $60/hr, 3 shifts/day, 365 days/yr)					
Material Cost	1.00	x Labor	$65,700	$65,700	$65,700
Testing					
Quarterly Portable Analyzer Test ($600 each)			$2,400	$2,400	$2,400
Annual Reference Method Stack Test			$15,000	$15,000	$15,000
Utilities & Operating Expenses					
Electricity [4, 5]			$18,952	$21,613	$37,978

Table A-4. EPNG - Williams - RH 2PP - 4FA - SCR for Engines - Costs

Name of Operator			El Paso Natural Gas	El Paso Natural Gas	El Paso Natural Gas
Mass Flow of Reagent (lb/hr) [7]			29.60	23.78	41.75
Mass Flow of 19% Ammonia (lb/hr)			155.77	125.18	219.72
Annual Cost of Ammonia ($/year) [3]			$275,387	$294,685	$541,003
Urea Consumption (gal/hr)			-	-	-
Urea Consumption (costs)	0.78	$/gal	-	-	-
Catalyst Required (ft^3) [8]			79	79	134
Catalyst Cost ($\$/ft^3$)			$249	$249	$249
Catalyst Cost ($)			$19,697	$19,697	$33,484
Future Worth Factor [9]			0.12	0.17	0.18
Annual Catalyst Replacement Cost			$2,432	$3,437	$6,159
Catalyst Installation	0.25	x replacement	$608	$859	$1,540
Total Direct Operating Cost, $/yr			**$570,904**	**$635,486**	**$909,196**
INDIRECT OPERATING COST					
Overhead					
60% of operators, supervisors, maintenance labor, and material	0.6		$153,675.68	$178,495	$183,069.68
Administrative charges	0.02	x CC	$11,000	$11,000	$11,000
Property Taxes	0.01	x CC	$6,000	$6,000	$6,000
Insurance	0.01	x CC	$6,000	$6,000	$6,000
Capital Recovery Factor			0.1424	0.1424	0.1424
Remaining useful life of source			10	10	10
Interest Rate			7%	7%	7%
Capital Recovery Cost			$80,617	$80,481	$80,901
Total Indirect Operating Cost, $/yr			**$257,292**	**$281,976**	**$286,970**
TOTAL ANNUAL OPERATING COST - 2019 Dollars			**$828,196**	**$917,461**	**$1,196,167**
TOTAL ANNUAL OPERATING COST - 2028 Dollars [10]			**$1,035,246**	**$1,146,827**	**$1,495,209**
2028 Projected NO_x Emissions (tpy)			**148.40**	**170.40**	**205.16**
NO_x Removed (tpy)			**130.78**	**144.93**	**177.45**
Cost of Control ($/ton NO_x removed)			**7,916**	**7,913**	**8,426**

Table A-4. EPNG - Williams - RH 2PP - 4FA - SCR for Engines - Costs

Name of Operator			El Paso Natural Gas	El Paso Natural Gas	El Paso Natural Gas

[1] Chemical Engineering Plant Cost Index

Year	Index
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

[2] Per 2028 Projections

[3] Cost of 19% Ammonia: 0.49 $/lb

[4] Industrial electricity rate at Williams Compressor Station: 0.476 $/kW-hr

[5] Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equations 2.48 and 2.49, assuming the following values:

ΔP_{duct}	3	in.
n_{total}	2	
$\Delta P_{catalyst}$	1	in.

[6] Per 2019 Source Test.

[7] Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.35

[8] Assuming catalyst required is 1.5 m^3/MW

[9] Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equations 2.65 and 2.66 assuming the following:

	Recip-1	Recip-2	Recip-5
Interest Rate	7%	7%	7%
Catalyst Operating Life (hours)	24000	24000	24000
SCR annual operating time (hours)	3615.25	4814.25	5035.25

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

Table A-5. EPNG - Williams - RH 2PP - 4FA - SCR for Turbines - Costs

Parameter	Short name	Calculation	El Paso Natural Gas [1]	Units	Reference
Location			Williams		
Turbine Make			GE		
Turbine Model			M5322R		
Exhaust Parameters					
Heat Input Rate	Q_b		197.3	MMBtu/hr	Per 2019 Permit Renewal Application
Exhaust Temperature			972.0	deg F	Per 2019 Source Test
Exhaust Temperature			795.4	deg K	
Exhaust Flow	$q_{fluegas}$		76,445	acfm	Per 40 CFR Part 75 Appendix F, Table 1 , F-Factor of 8,710 dscf/MMBtu
Operating Temperature	T	Vendor Data	860	deg F	
Operating Hours Per Year	AOH	Max	4,951	hours	
Inlet Concentration	NOx_{in}		0.67	lb/MMBtu	2019 source test
Inlet Concentration	NOx_{in}		202	ppmv	Source Test
Outlet Concentration	NOx_{out}		61	ppmv	70% control efficiency per EPA Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032
Outlet Concentration	NOx_{out}		0.201	lb/MMBtu	
Available Cost Data					
Capital Cost of Ammonia Catalyst	$CC_{initial}$	$(8000/m^3)/(35.1347\ ft^3/m^3)$	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	$/lb	Vendor quotes from 2011 to 2013. Adjusted from 2012 dollar.
Industrial electricity rate at Williams Compressor Station	$TAIE_{cost}$		0.476	$/kWh	
Chemical Properties and Constants					
19% Ammonia Solution Density	Den_{NH3}		7.51	lbs/gal	Per CFIndustries Aqua Ammonia 19% Safety Data Sheet.
Ammonia MW	$M_{reagent}$		17.03	g/mol	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction
NO_2 MW	M_{NOx}		46.01	g/mol	
Ratio of Equivalent Moles of NH_3 per Mole of Reagent Injected	$SR_{theoretical}$		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	mol NH3:mol NOx	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.3.7
Constant 1	C1		7	ft	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.3.12
Constant 2	C2		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	layers	Value assumed for lowest capital cost
Nominal Height of Each Catalyst Layer	h'_{layer}		3.1	ft	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.3.12
Number SCR Chambers	n_{scr}		1	chamber	Value assumed for lowest capital cost
Allowable Slip	Slip		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	in	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.5
Pressure Drop due to Catalyst	$\Delta P_{catalyst}$		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	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	%	Calculated
Cross Sectional Area of Catalyst	$A_{catalyst}$	$q_{fluegas}/(16ft/sec\ x\ 60\ sec/min)$	80	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 $A_{catalyst}$)	92	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	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		Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.24
Inlet NOx Adjustment	NOx_{adj}	$(0.8524+(0.3208*NOX_{in}))$	1.07		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		Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.23
Volume of Catalyst	Vol_{cat}	$2.81*Q_b*\eta_{adj}*NOX_{adj}*Slip_{adj}*T_{adj}/n_{scr}$	1,115	ft^3	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.22
Height of catalyst layer	h_{layer}	$Vol_{catalyst}/(N_{layer}*A_{catalyst})+1$	4	ft	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.32
Number of catalyst layers	n_{layer}	$Vol_{catalyst}/(h'_{layer}*A_{catalyst})$	5	layers	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.31
Total Number of catalyst layers	n_{total}	$n_{layer} + n_{empty}$	5	layers	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.33
Height of SCR	h_{scr}	$n_{total}*(C1+h_{layer})+C2$	63	ft	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.34
Mass flow of reagent	$m_{reagent}$	$(NOx_{in}*Q_b*\eta_{NOx}*SRF*M_{reagent})/(M_{NOx})$	36	lb/hr	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.35
Mass flow of solution	m_{sol}	$m_{reagent}/C_{sol}$	190	lb/hr	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.36

Table A-5. EPNG - Williams - RH 2PP - 4FA - SCR for Turbines - Costs

Parameter	Short name	Calculation	El Paso Natural Gas [1]	Units	Reference
Direct Costs					
Catalyst Cost	f(Vol)	$Vol_{cat}*CC_{initial}$	277,999	$	Calculated
Ammonia Flow Adjustment	f(NH3)	$411/(lb/hr)*$m_{reagent}/Q_b$-$47.3/MMBtu/hr	43	$/(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	306	$/(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	$/(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	$/(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	$	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}	2,870,179	$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.36 Adjusted from 1998 dollar
Indirect Costs					
Annual Reference Method Test	PT_{cost}	Budgetary Cost	15,000	$	-
General Facilities	GF_{cost}	0.05*DC	143,509	$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Table 2.5
Engineering and Home Office Fees	EO_{cost}	0.10*DC	287,018	$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Table 2.5
Process Contingency	PC_{cost}	0.05*DC	143,509	$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Table 2.5
Total Indirect Installation Costs	B	$PT_{cost}+GF_{cost}+EO_{cost}+PC_{cost}$	589,036	$	Calculated
Project Contingency	C	0.15*(DC+B)	518,882	$	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.4.1
Total Plant Costs	D	DC+B+C	3,978,097	$	-
Preproduction Costs	G	0.02*D	79,562	$	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	31,146	$	Based on 14 days of SCR operation, 24 hrs/day
Total Capital Investment	TCI	D+G+H	**4,088,804**	**$**	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	165,349	$	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}	24,802	$	Per 2002 EPA Cost Manual
Annual Maintenance Costs	AM_{cost}	0.015*TCI*2	122,664	$	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	458,888	$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.58
Annual Electricity Costs	AE_{cost}	0.105*Qb*($NOx_{in}*\eta_{NOx}+0.5(\Delta P_{duct}+n_{total}+\Delta P_{catalyst})$)*AOH*$TAIE_{cost}$	218,198	$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equations 2.48 and 2.49
Quarterly Portable Tests		4*600	2,400	$	$600 per test, performed quarterly
Catalyst Replacement Costs	CR_{cost}	$n_{scr}*Vol_{cat}*(CC_{initial}/n_{layer})$	55,600	$	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		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	11,453	$	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.64.
Direct Annual Costs	DA_{cost}	$OL_{cost}+SL_{cost}+AM_{cost}+AR_{cost}+AE_{cost}+RATA_{cost}+ACR_{cost}$	**1,059,354**	**$/year**	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.56.

Table A-5. EPNG - Williams - RH 2PP - 4FA - SCR for Turbines - Costs

Parameter	Short name	Calculation	El Paso Natural Gas [1]	Units	Reference
Indirect Annual Costs					
Administrative Charges	A_{cost}	0.03*OLcost+0.4*AMcost	54,026	$/year	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.69.
Overhead Costs		$0.6*(OL_{cost}+SL_{cost}+AM_{cost})$	187,689	$/year	Per 2002 EPA Cost Manual, Page 2-34.
Indirect Annual Costs	IAcost	A_{cost}	241,715	$	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.68
Annualized Capital Cost	AC_{cost}	CRF*TCI	448,929	$/year	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.70
Interest Rate	i		7%		Per EPA Cost Manual Chapter 2 Cost Estimation: Concepts and Methodology
SCR System Life	Life		15	years	Per ADEQ guidance, equipment life of turbine from time of installation (2028).
Capital Recovery Factor	CRF	$i(1+i)^{life}/((1+i)^{life}-1)$	10.98%		Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.71
Total Annual Costs	TAC	ACcost+DAcost+IAcost	1,749,998	$/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	229	ton/yr	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.11
Cost Effectiveness		**$TAC/NOx_{removed}$**	**7,629**	**$/ton**	**Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.73**

[1] 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
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	-

Table A-6. EPNG - Williams - RH 2PP - 4FA - Clean Burn Conversion - Operating Costs

Name of Operator			**El Paso Natural Gas**	**El Paso Natural Gas**	**El Paso Natural Gas**
Location			Williams	Williams	Williams
Control			LEC 1	LEC 2 [2]	LEC 3 [2]
Engine Make			Clark	Clark	Clark
Engine Model			TLA6/TLA10	TLA6/TLA10	TLA6/TLA10
Engine Type			2SLB	2SLB	2SLB
Date of Quote			N/A	N/A	N/A
DIRECT OPERATNG COST					
Operating Labor					
Operator Labor			$1,440	$2,880	$3,744
(8 hr/mn day @ $60/hr, 3 mn day/year)					
Supervision, 15% of Operator	0.15	x Operator	$216	$432	$562
Maintenance					
Labor			$32,850	$65,700	$85,410
(0.5 hrs/shift @ $60/hr, 3 shifts/day, 365 days/yr)					
Material Cost	1.00	x Labor	$32,850	$65,700	$85,410
Testing					
Annual Reference Method Stack Test			$15,000	$15,000	$15,000
Utilities & Operating Expenses					
Electricity			$5,000	$10,000	$13,000
Total Direct Operating Cost, $/yr			**$87,356**	**$159,712**	**$203,126**
INDIRECT OPERATNG COST					
Overhead					
60% of operators, supervisors, maintenance labor, and material	0.6		$40,414	$80,827	$105,075
Total Indirect Operating Cost, $/yr			**$40,414**	**$80,827**	**$105,075**
TOTAL ANNUAL OPERATING COST - 2019 Dollars			**$127,770**	**$240,539**	**$308,201**

[1] Chemical Engineering Plant Cost Index

Year	**Index**
2017	567.5
2018	603.1

[2] Because LEC 1, LEC 2, and LEC 3 are cumulative control options, a retrofit factor of 2 and 2.6 was applied to LEC 2 and LEC 3 respectively to incorporate the additional cost of maintenance, labor, and materials as the control options accumulate.

Regional Haze - Four-Factor Analysis - Control Technology Evaluation & Cost Analysis
Replacement Turbine

Table A-7. EPNG - Williams - RH 2PP - 4FA - Engines Replacement with Low-Emitting Unit

Parameter			Value
Potential NOx Reduction			
New Turbine Size (hp) [1]			15,900
Outlet NOx (g/hp-hr) [2]			0.35
Inlet NOx (tpy) [3]			523.97
Outlet NOx (tpy) [4]			53.74
NOx Reduced (tpy)			470.23
Capital Implementation Costs			
Capital Investment ($)			$25,850,426
Total Capital Investment			**$25,850,426**
Capital Recovery Factor [5]			0.0944
Annualized Cost ($/yr)			$2,440,097
Component Exchange ($/yr) [6]			$500,000
Admin, Tax, Insurance ($/yr) [7]			$1,034,017
Annual Reference Method Stack Test ($/yr)			$15,000
Labor Cost - Unmanned Station ($/yr)			$1,440
Supervisor ($/yr)	0.15	x Labor	$216
Maintenance and Materials ($/yr) [8]			$70,000
2019 Total Annual Cost ($/yr)			**$4,060,770**
2028 Total Annual Cost ($/yr) [9]			**$5,075,963**
2019 Cost Effectiveness ($/ton)			**$8,636**

[1] New 15,900 hp Solar Mars 100 to replace Engines RECIP-1, RECIP-2, and RECIP-5.

[2] Per vendor quote.

[3] The new turbine will replace Engines RECIP-1, RECIP-2, and RECIP-5. As such, inlet NOx includes NOx emissions from RECIP-1, RECIP-2, and RECIP-5.

[4] Conservatively assumed that new turbine will operate 8,760 hours per year.

[5] For installation of new low-emitting turbine:

Interest Rate	7%
Remaining useful life of source	20
Capital Recovery Factor	0.0944

[6] Solar Component Exchange - Every 40,000 hours of operation hours; assumed every 5 years to be conservative.
$2.5 million cost based on 2019 actual incurred cost.

[7] Admin, Taxes, Insurance assumed to be: 4%
Per EPA Air Pollution Control Cost Manual, Seventh Ed., 2017, Sect. 2.6.5.8, pg 2-35

[8] Maintenance and materials cost obtained from 2019 actual cost for maintaining a Solar Mars 100 at Seligman Compressor Station, AZ.

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