REGIONAL HAZE FOUR-FACTOR ANALYSIS
Xcel Energy, Cunningham Station

Prepared By:

Jake Zenker - Consultant
Adam Erenstein – Manager of Consulting Services

TRINITY CONSULTANTS
9400 Holly Ave.
Building 3, Suite 300
Albuquerque, NM 87122
(505) 266-6611

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1. EXECUTIVE SUMMARY

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 conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977.

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 for a Class I area, each state must:

(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. 40 CFR 51. 308(d)(1)(i)(A).* This is known as a four-factor analysis.

(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. 40 CFR 51. 308(d)(1)(i)(B).* The uniform rate of progress or improvement is sometimes referred to as the glidepath and is part of the state's Long Term Strategy (LTS).

The second implementation planning period (2018-2028) for national regional haze efforts is currently underway. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural or biogenic and manmade or anthropogenic sources of emissions. Using a Photochemical Grid Model (PGM), the Western Region Air Partnership (WRAP), in coordination with the EPA, is tasked with comparing anthropogenic source contributions against natural background concentrations.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for major sources and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I area. From this analysis, 24 facilities were identified by the NMED. On July 18, 2019 the NMED informed Xcel Energy (Xcel), that its Cunningham Station (Cunningham) was identified as one of the sources potentially contributing to regional haze at the CarlsbadCaverns National Park Class I area.

In coordination with guidance provided by WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. The NMED's July 18, 2019 notification letter to Xcel specifies that any equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The NMED also provided additional guidance that only steady-state emissions shall be considered in the four-factor analysis. Therefore, the emergency generator (Unit EGR1) is not discussed in this report. The equipment at the facility that is subject to the analysis, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant are reported in Table 1.

Table 1. Summary of Equipment and Applicability of the Four-Factor Analysis

Equipment	NO_X Hourly PTE (lb/hr)	NO_X Annual PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
Natural Gas-Fired Boiler (Unit 1)	235.20	1030.00	Yes	2.90	12.90	No
Natural Gas-Fired Boiler (Unit 2)	585.30	2564.00	Yes	7.30	32.20	No
Natural Gas-Fired Turbines – Normal Operation (Units 3 &4)	78.10	170.90	Yes	22.10	55.10	Yes
Natural Gas-Fired Turbines – Augmented Operation (Units 3 &4)	129.00	38.70	Yes	-	-	No

Once the applicability of process equipment and pollutants has been determined, potential retrofit control technologies must be identified. In accordance with 40 CFR 51 Appendix Y and at recommendation of the NMED[1], this is primarily achieved by utilizing the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) data. In order to determine the most relevant and current retrofit controls available, the RBLC is queried for the previous ten years. Summaries of the result of this search are provided and discussed under Section 2 of this report. The facility engineers then reviewed the list of available retrofit technologies and performed a technical feasibility assessment for each control option. The four-factor analysis is then conducted for those controls that are technically feasible.

[1] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

2. BACKGROUND INFORMATION & TECHNICAL FEASIBILITY

2.1. COMBUSTION TURBINES

As reported in Table 1 Cunningham's two natural gas-fired simple cycle peaking turbines, Units 3 and 4, are NO_x and SO_2.

2.1.1. Combustion Turbine Background

A gas turbine is an internal combustion engine that operates with a rotary, rather than reciprocating, motion and is composed of three primary components: a compressor, a combustor, and a power turbine. The compressor draws in ambient air and compresses it up to 30 times the ambient pressure, then directs it into the combustor where fuel is introduced, ignited, and burned. Exhaust gas from the combustor is then diluted with additional air and sent to the power turbine at temperatures up to 2600 °F. The hot exhaust gas expands in the power turbine section, generating energy in the form of shaft horsepower.[2]

The treatment of the exhaust gases exiting the turbine dictates the cycle designation of these units. The heat content can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).[3] The units at Cunningham are simple cycle turbines.

NO_X is formed via three fundamentally different mechanisms. The principle NO_X formation mechanism, thermal NO_X, arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion. Most thermal NO_X forms in the highest temperature regions of the combustion chamber. The second NO_X formation mechanism, fuel NO_X, arises from the evolution and reaction of fuel bound nitrogen compounds with oxygen. The final NO_X formation mechanism, prompt NO_X, arises from early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The significance of prompt NO_X is negligible in comparison to thermal and fuel NO_X. Fuel NO_X will also be negligible for Cunningham's turbines assessed here, as these combustion turbines fire natural gas, which contains a negligible amount of nitrogen compounds. Therefore, this analysis will focus on thermal NO_X.

The PTE from each turbine referenced from the facility's PSD (0622) and Title V (P080) permits are summarized in Table 1. There are two operational modes associated with these units: with and without power augmentation. NO_x composition of stack gas during normal operations is approximately 15 ppmv, whereas the composition during power augmentation is 25 ppmv. A safety factor is then applied to these emissions to calculate the PTE represented in the permits for these unit.

SO_2 emissions from turbines are generated when sulfur in fuel gas is combusted in the turbine. The PTE for SO_2 is calculated with an assumed conservative fuel gas sulfur content of 5.25 gr S/100 scf. The PTE for these units is calculated based on this fuel sulfur content and is represented in Cunningham's NSR and Title V permits as 22.1 lb/hr/unit.

[2] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"

[3] Ibid.

2.1.2. Potential NO_X Controls for a Combustion Turbine

There are three general methods of controlling NO_X emission from gas turbines; (1) wet controls, which use steam or water injection to reduce combustion temperatures and NO_X formation, (2) dry controls that use advanced combustor design to suppress NO_X formation, and (3) post-combustion, catalytic controls to selectively reduce NO_X.[4]

The retrofit control equipment that was identified for combustion turbines during a comprehensive review of the RBLC, available literature, and manufacturer's input is reported in Table 2. A more detailed table summarizing the RBLC review is provided in Appendix A. A detailed discussion, including a description, the technical feasibility, and the anticipated performance of each control is provided below.

Table 2. Potential Control Equipment for Combustion Turbines

Control Equipment	Technically Feasible	NO_X Control Efficiency
Dry low NO_X	**Currently Installed**	**N/A**
Improved dry low NO_X	**No**	**N/A**
Water Injection	**Yes**	**15%**
Steam Injection	**No**	**N/A**
Selective Catalytic Reduction	**Yes**	**65%**

2.1.2.1. 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 cylinder 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 units at Cunningham. However, these practices are currently in use at Cunningham, as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices has been included in this report.

2.1.2.2. Improved Dry Low NO_X Hardware

The dry low NO_X (DLN) control, also seeks to reduce the combustion temperature and residence time of fuel in the combustor (thereby decreasing NO_X formation) by increasing the air-to-fuel ratio in the combustion

[4] Ibid.

chamber. There are several levels of improvements that can be made to the combustion chamber, which achieve this NO_X control at varying levels.

DLN combustors are currently installed on the combustion turbines operating at this facility. While emissions may fluctuate, on average, the turbines installed at this facility are capable of achieving a NO_X stack concentration of 15 ppm and 25 ppm during normal and power augmented operation, respectively. According to Seimens, there are no improved low NO_X burners commercially available for these units.

2.1.2.3. Water/Steam Injection

Water or steam injection is a technology that has been demonstrated to effectively suppress NO_X emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.

Xcel engineers stated that Steam injection may not be implemented on the combustion turbines at Cunningham.

The pilot nozzle is the main contributor to thermal NO_x formation and water injection is capable of reducing NO_x emissions with a minimum control efficiency of 15%.[5]

2.1.2.4. Selective Catalytic Reduction Systems

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust downstream of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[6] The chemical reactions for this process are shown in the equations below.

$$4\,NO + 4\,NH_3 + O_2 \rightarrow 4\,N_2 + 6\,H_2O \qquad \text{(Equation 1)}$$
$$2\,NO_2 + 4\,NH_3 + O_2 \rightarrow 3\,N_2 + 6\,H_2O \qquad \text{(Equation 2)}$$

An SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and an electronic control system. The electronic controls regulate the quantity of reagent injected as a function of turbine load, speed, and temperature, so NO_X emissions reductions can be achieved. The lifespan of the catalyst is primarily determined by poisoning of active sites by flue gas constituent, thermal sintering, or compacting, of active sited due to high temperatures in the reactor, fouling caused by ammonia-sulfur salts and particulate matter in the gas, and erosion due to high gas velocities.[7]

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as ammonia slip. Unreacted ammonia in the exhaust can form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.[8]

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[5] Ibid.
[6] 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.
[7] Ibid.
[8] Ibid.

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. Exhaust gas temperatures greater than the upper limit will cause the NO_X and ammonia to pass through the catalyst unreacted.[9] The exhaust temperature of the turbines assessed here is approximately 580 °F.

SCR units can achieve a minimum NOx reduction of 65%.[10] However, if the upstream NO_X concentration is already low, as is the case with these units, it is difficult to achieve these control efficiencies.

There may also be site-specific space limitations that prevent the installation of the necessary equipment for this control method (i.e., SCR module and reagent storage systems).

Moreover, installation of SCR on simple cycle peaking turbines is much more difficult than installation on combined cycle turbines operating as base load units for several reasons, as follows:

- There are significant technical and financial challenges associated with the elevated exhaust temperature from simple cycle operation;
- Combined-cycle facilities have heat recovery steam generator (HRSG) ductwork that can better accommodate catalyst installation; and
- Combined-cycle cogeneration units typically operate in a continuous mode compared to peaking units which do not operate continuously and ramp up and down quickly from standing start to full load operation.

Assuming that the space and temperature limitations can be overcome, SCR is considered a technically feasible control option for this process.

2.1.3. Potential SO_2 Controls for a Combustion Turbine

2.1.3.1. Good Combustion Practices and Fuel Selection

As stated in the background information for emissions from combustion turbines, SO_2 emissions from these units are based on the sulfur content of the fuel gas. The current permitted SO_2 PTE for the turbines is based on a fuel sulfur content of 5.25 gr/100 scf. These emissions were originally permitted under PSD Permit No. 0622-M2 issued on 2/10/1997. At the time, this was consistent with Xcel's definition of "sweet gas" and the representative sulfur content was considered appropriately conservative. However, the actual sulfur content at the facility is typically 0.3 gr/100 scf and does not ever exceed 1.25 gr/100 scf. According to 2016 emission inventory data, which is based off continuous emission monitoring system (CEMS) data, actual SO_2 emissions for these units are less than 1 lb/hr on average. No additional sulfur reduction controls are reasonable or necessary.

2.2. INDUSTRIAL BOILERS

2.2.1. Industrial Boilers Background

As with natural gas turbines, of the three NO_X formation mechanisms, both fuel and prompt NO_X are negligible for natural gas industrial boilers. Thermal NO_X results from the oxidation of atmospheric nitrogen in the high-temperature, post-flame region of a combustion system. The major factors that influence thermal NO_X formation

[9] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines".

[10] Ibid.

are temperature, concentrations of oxygen and nitrogen, and residence time. If the temperature or the concentration of oxygen or nitrogen can be reduced quickly after combustion, thermal NO_X formation can be suppressed or quenched.

The formation of thermal, prompt, and fuel NO_X in combustion systems is controlled by modifying the combustion gas temperature, residence time, and turbulence. Of primary importance are the localized conditions-within and immediately following the flame zone where most combustion reactions occur. In utility boilers, temperature, residence time, and turbulence are determined by factors associated with boiler and burner design, fuel characteristics, and boiler operating conditions.

2.2.2. Potential NO_X Controls for Industrial Boilers

The retrofit control equipment identified for industrial boilers during a comprehensive review of the RBLC are reported in Table 3. A detailed discussion including a description, the technical feasibility, and the estimated performance of each control, is provided below.

Table 3. Potential Control Equipment for Industrial Boilers

Control Equipment	Technically Feasible	NO_X Control Efficiency
Good Combustion Practices	**Base Case**	**N/A**
Combustion Control Techniques	**Base Case for Unit 2, No for Unit 1**	**N/A**
Flue Gas Recirculation	**No**	**N/A**
Selective Catalytic Reduction	**Yes**	**80%**

2.2.2.1. 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 cylinder 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 boilers; therefore, it has been determined that this method of NO_X control is feasible for the units at Cunningham. However, these practices are currently in use at Cunningham, as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices has been included in this report.

2.2.2.2. Combustion Control Techniques

Similar to low NO_X burners for turbines, these controls reduce NO_X by sectioning the combustion process into stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_X formation. Minimum NO_X emission reductions of 40% have been observed with low NO_X burners [11].

Xcel has implemented an overfire air control on Unit 2 at this facility, which involves modifying the fourth level of combustion burners in the boiler. Unit 1 at the facility only has three levels of combustion burners and cannot be modified to include the overfire air technique used on Unit 2. Moreover, there are no commercially available controls that may be installed on these units at this time.

Based on this information, Xcel cannot implement any additional low NO_X burners or staging modifications at this time and no options are evaluated in this report.

2.2.2.3. Flue Gas Recirculation

In a Flue Gas Recirculation (FGR) system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed into the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NO_X emissions by two mechanisms. Primarily, the recirculated gas acts as a diluent to reduce combustion temperatures, thus suppressing the thermal NO_X formation mechanism. To a lesser extent, FGR also reduces NO_X formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is a key operating parameter influencing NO_X emission reduction potential for these systems.

FGR on these boilers would require ductwork and structural steel additions to bring exhaust gas from the stack back into the furnace windboxes. This would necessitate a re-design of the windboxes so that they could properly receive the new source and damper changes to properly mix the flow and maintain the proper air/fuel ratio. This option would also require an additional fan in the new duct work to match the pressure of the existing FD fan. Additionally, the air portion of the burner nozzles in the boilers would also need to be enlarged. The entire system would require extensive controls changes to balance air and fuel. While the cost of the FGR would likely not justify this modification, since the technique would provide a limited reduction in NO_X, the modifications needed to implement FGR are prohibitive. Moreover, Xcel has determined that the structural changes required to implement this control cannot be incorporated in due to space limitations at the facility.

This option is not considered technically feasible and is therefore not evaluated further in this report.

2.2.2.4. Selective Catalytic Reduction

The selective catalytic reduction (SCR) system for industrial boilers involves injecting ammonia (NH_3) into the flue gas in the presence of a catalyst to reduce NOx emissions. No data were available on SCR performance on

[11] U.S. EPA, AP-42, Section 1.4, "Natural Gas Combustion"

natural gas-fired boilers at the time of this publication. However, the Alternative Control Techniques (ACT)[12] document for utility boilers estimates a minimum NO_X reduction efficiency of 80%.[13]

This control is considered technically feasible and is assessed further in this report.

[12] 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.

[13] U.S. EPA, AP-42, Section 1.4, "Natural Gas Combustion"

Xcel has evaluated the costs of implementing the technologically feasible control technologies as thoroughly as possible in the time provided to complete this assessment. These cost estimates are calculated according to the methods and recommendations in the EPA Air Pollution Control Cost Manual or are estimated based on cost estimated provided by equipment vendors.[14] The cost effectiveness discussion and summary tables for the turbines are provided in Table 4.

3.1. TURBINE CONTROLS

Table 4. Cost Analysis Summary of Technically Feasible Controls for Combustion Turbines

Control Equipment	Unit No.	Cost Effectiveness	Cost Factors
Water Injection	3 4	$81,395 per ton $41,515 per ton	Equipment costs, Annual operating costs.
Selective Catalytic Reduction	3 4	$97,583 per ton $49,771 per ton	Equipment costs, Annual operating costs.

3.1.1. Water Injection

Xcel received a cost estimate to implement water injection control on the combustion turbine at the Cunningham Station. This cost estimate is reported to be $2.24 million per unit for equipment, plus an additional $340,000 associated with annual operating cost. The control efficiency for water injection is estimated to be 15% resulting in an emission rate reduction of 6.48 tpy and 12.71 tpy for Units 3 and 4, respectively. This results in an estimated cost effectiveness of $81,395and $41,515 per ton of reduced emissions for Units 3 and 4, respectively.

3.1.2. Selective Catalytic Reduction

Xcel obtained total cost estimates for a turbine SCR from CECO-Peerless. The estimate incorporates direct capital cost for equipment and vendor labor, indirect costs associated with Xcel's internal labor, and overhead and contingency costs for the project. According to this estimate, the SCR would cost $30.2 million per unit with $207,794 per year in operating costs. According to the manufacturer guaranteed control performance, the unit will reduce NO_X emissions with an 65% efficiency resulting in an emission rate reduction of 28.08 tpy and 55.06 tpy for Units 3 and 4, respectively. This results in an estimated cost effectiveness of $97,583 and $49,771 per ton of reduced emissions for Units 3 and 4, respectively.

[14] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

3.2. INDUSTRIAL BOILER CONTROLS

Table 5. Cost Analysis Summary of Technically Feasible Controls for Industrial Boilers

Control Equipment	Unit No.	Cost Effectiveness	Cost Factors
Selective Catalytic Reduction	1	$9,451 per ton	Equipment costs, Annual operating costs
	2	$5,229 per ton	

3.2.1. Selective Catalytic Reduction

To estimate the cost of a SCR unit for the boilers operating at the Cunningham Station, Xcel utilized the EPA Cost Control Manual spreadsheet. According to the cost estimation spreadsheet, the cost for Unit 1 would be $11.1 million with $145,035 annual direct costs, and $830,337 in annual indirect costs. The lifetime of the control is estimated to be 20 years and the emissions reduction from this control is estimated to be 114.00 tpy based on an assumed 80% control efficiency and uncontrolled annual emissions of 142.5 tpy (2016 emission inventory data). This results in a cost of $9,451/ton NO_X removal.

Unit 2 would cost $21.98 million with $620,558 in annual direct costs, and $1.84 million in annual indirect costs. The lifetime of the control is estimated to be 20 years and the emissions reduction from this control is estimated to be 471.12 tpy based on an assumed 80% control efficiency and uncontrolled annual emissions of 588.90 tpy (2016 emission inventory data). This results in a cost of $5,229/ton NO_X removal.

The second factor in this analysis is the time necessary for compliance. Consideration of this factor involves estimating the time required for a source to implement a potential control measure. This information is provided here in order to advise the NMED of Xcel's projection of a reasonable compliance timeline based on the equipment and site-specific considerations that could affect the time necessary to comply.

4.1. TURBINE CONTROLS

4.1.1. Water Injection

Xcel estimates that approximately 18 months will be needed to order, deliver, and install this equipment at the Cunningham Station.

4.1.2. Selective Catalytic Reduction

Xcel estimates that approximately 30 months will be needed to budget, design, procure, and construct this equipment.

4.2. INDUSTRIAL BOILER CONTROLS

4.2.1. Selective Catalytic Reduction

Xcel estimates that approximately 30 months will be needed to budget, design, procure, and construct this equipment.

5.1. TURBINE CONTROLS

5.1.1. Water Injection

Water injection is usually accompanied by an efficiency penalty (typically 2% to 3%), but an increase in power output (typically 5% to 6%).[15] The increased power output results from the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are significantly increased by water injection, with the level of CO and VOC increases dependent on the amount of water injection.[16] This increase in emissions could potentially warrant the installation of an oxidation catalyst, levying significant additional costs on Xcel to implement this control.

Additionally, depending on the model and capacity of a turbine, approximately 31 to 70 gpm may be needed to properly implement this control.[17] For a continuously operating turbine, this would represent a total water usage of 16.3 to 36.8 million gallons per year, per unit, without taking into consideration leaks and evaporative losses that would occur during transport. The implementation of this control across the Permian Basin may pose a significant burden on this semi-arid region's watershed, in which water availability is relatively sparse.

5.1.2. Selective Catalytic Reduction

The implementation of SCR on the turbines at the Cunningham Station would result in several energy and non-air environmental impacts. The primary impact of this control would be a significant increase in energy consumption, which would be necessary to power the units. Xcel does not anticipate any issues with meeting this increased energy burden.

In addition to the increased energy burden, there are several non-air environmental impacts associated with the handling and storage of the reagent used in the SCR system, typically ammonia or urea. Ammonia is a Toxic Air Pollutant (TAP) regulated under 20.2.72.502 NMAC with an occupational exposure limit (OEL) of 18 mg/m^3. In both soil and water, urea is hydrolyzed quickly to ammonia and carbon dioxide by urease, an extracellular enzyme that originates from microorganisms and plant roots.[18] Short-term inhalation exposure to high levels of ammonia in humans can cause irritation and serious burns in the mouth, lungs, and eyes. Chronic exposure to airborne ammonia can increase the risk of respiratory irritation, cough, wheezing, tightness in the chest, and impaired lung function in humans. Animal studies also suggest that exposure to high levels of ammonia in air may adversely affect other organs, such as the liver, kidney, and spleen.[19] Unavoidable releases of ammonia could have significant and irreversible impacts on the living and physical environment affected. Storage and handling of urea or ammonia onsite would result in an increased risk to the health and safety of facility operators.

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[15] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines".

[16] Ibid.

[17] GE Turbines: "Water Reduction for NO_X". https://www.ge.com/power/services/gas-turbines/upgrades/water-injection-for-nox-reduction.

[18] U.S. EPA, EPA/635/R-10/005F, "Toxilogical Report of Urea", July 2011.

[19] U.S. EPA, EPA/635/R-16/163Fc, "Toxicological Review of Ammonia Noncancer Inhalation: Executive Summary", September 2016.

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5.2.1. Selective Catalytic Reduction

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[20] U.S. EPA, EPA/635/R-10/005F, "Toxilogical Report of Urea", July 2011.
[21] U.S. EPA, EPA/635/R-16/163Fc, "Toxicological Review of Ammonia Noncancer Inhalation: Executive Summary", September 2016.

6. REMAINING USEFUL LIFE OF SOURCES

6.1. TURBINE CONTROLS

6.1.1. Water Injection

The estimated lifetime of a water injection control system is 15 years. This estimate has been incorporated in the cost analysis section to calculate the total annualized cost of the control.

6.1.2. Selective Catalytic Reduction

The estimated lifetime of a SCR control system is 20 years. This estimate has been incorporated in the cost analysis section to calculate the total annualized cost of the control.

6.2. INDUSTRIAL BOILER CONTROLS

6.2.1. Selective Catalytic Reduction

The estimated lifetime of a SCR control system is 20 years. This estimate has been incorporated in the cost analysis section to calculate the total annualized cost of the control.

7. RESULTS & CONCLUSION

Based on a comprehensive review of the RBLC, available literature, and manufacturer's input on the available control technologies for the natural-gas fired turbines located at the Cunningham Station, Xcel has determined that it is not technically feasible or cost effective to implement any controls on equipment at this time.

Xcel Energy
Cunningham Station

Boiler	Interest Rate:	5.50%	
Unit 1	Period:	20	years

Base Emissions

NO_X lb/hr:	63.25	lb/hr	<-- From 2016 EI calculations
NO_X tpy:	142.50	tpy	<-- From 2016 EI calculations

SCR

NO_X guarantee:		80%	Control Eff.	<-- Assumed for SCR, AP-42 Section 1.4.4
NO_X lb/hr:		12.65	lb/hr	
NO_X tpy:		28.50	tpy	
Total Cap Investment	$	11,118,368		<--EPA Cost Estimate Spreadsheet
Annualized TCI:	$	930,378		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	147,054		<--EPA Cost Estimate Spreadsheet
Total Annual Costs:	$	1,077,431		
Emissions Reduction:		114.00	tpy	
Cost Effectiveness:	**$**	**9,451.15**	**$/ton**	

Xcel Energy

Cunningham Station

Boiler	Interest Rate:	5.50%	
Unit 2	Period:	20	years

Base Emissions			
NO_X lb/hr:	146.49	lb/hr	<-- From 2016 EI calculations
NO_X tpy:	588.90	tpy	<-- From 2016 EI calculations

SCR			
NO_X guarantee:	80%	Control Eff.	<-- Assumed for SCR, AP-42 Section 1.4.4
NO_X lb/hr:	29.30	lb/hr	
NO_X tpy:	117.78	tpy	
Total Cap Investment	$ 21,981,248		<-- EPA Cost Estimate Spreadsheet
Annualized TCI:	$ 1,839,376		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 624,288		<-- EPA Cost Estimate Spreadsheet
Total Annual Costs:	$ 2,463,665		
Emissions Reduction:	471.12	tpy	
Cost Effectiveness:	**$ 5,229.38**	**$/ton**	

Xcel Energy
Cunningham Station

Turbine	Interest Rate:	5.50%		
Unit 3	SCR Period:	20	years	
	Water Injection Period:	15	years	
Base: Dry Low NO_X				
NO_X lb/hr:		54.10	lb/hr	<-- From 2016 Emission Inventory Report
NO_X tpy:		43.20	tpy	<-- From 2016 Emission Inventory Report

Water Injection

NO_X guarantee:		15%	Control Eff.	<-- Assumed for SCR, AP-42 Section 3.1.4.1
NO_X lb/hr:		45.99	lb/hr	
NO_X tpy:		36.72	tpy	
Total Cap Investment	$	2,240,000		<-- Vendor Estimate
Annualized TCI:	$	187,442		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	340,000		<-- Vendor Estimate
Total Annual Costs:	$	527,442		
Emissions Reduction:		6.48	tpy	
Cost Effectiveness:	**$**	**81,395.32**	**$/ton**	

[1] From Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Timeline for Compliance (Docket ID No. EPA-HQ-OAR-2015-0500) Section 3.3.1, Corrected from 1999 to 2018 dollars based on CEPCI.

SCR

NO_X guarantee:		65%	Control Eff.	<-- Assumed for SCR, AP 42 Section 3.4.1.3
NO_X lb/hr:		18.94	lb/hr	
NO_X tpy:		15.12	tpy	
Total Cap Investment	$	30,262,542		<-- From Vendor
Annualized TCI:	$	2,532,349		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	207,794		<-- from Vendor
Total Annual Costs:	$	2,740,143		
Emissions Reduction:		28.08	tpy	
Cost Effectiveness:	**$**	**97,583.46**	**$/ton**	

Xcel Energy

Cunningham Station

Turbine	Interest Rate:	5.50%		
Unit 4	SCR Period:	20	years	
	Water Injection Period:	15	years	
Base: Dry Low NO_X				
NO_X lb/hr:		59.48	lb/hr	<-- From 2016 Emission Inventory Report
NO_X tpy:		84.70	tpy	<-- From 2016 Emission Inventory Report

Water Injection

NO_X guarantee:		15%	Control %	<-- Assumed for SCR, AP-42 Section 3.1.4.1
NO_X lb/hr:		50.56	lb/hr	
NO_X tpy:		72.00	tpy	
Total Cap Investment	$	2,240,000		<-- Vendor Estimate
Annualized TCI:	$	187,442		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	340,000		<-- Vendor Estimate
Total Annual Costs:	$	527,442		
Emissions Reduction:		12.71	tpy	
Cost Effectiveness:	**$**	**41,514.50**	**$/ton**	

SCR

NO_X guarantee:		65%	Control %	<-- Assumed for SCR, AP-42 Section 3.1.4.3
NO_X lb/hr:		20.82	lb/hr	
NO_X tpy:		29.65	tpy	
Total Cap Investment	$	30,262,542		<-- From Vendor
Annualized TCI:	$	2,532,349		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	207,794		<-- from Vendor
Total Annual Costs:	$	2,740,143		
Emissions Reduction:		55.06	tpy	
Cost Effectiveness:	**$**	**49,771.02**	**$/ton**	