REGIONAL HAZE 2ND IMPLEMENTATION PERIOD
FOUR-FACTOR ANALYSIS

US Magnesium LLC, Rowley Plant - Tooele County

Prepared For:

US Magnesium LLC – Rowley Plant

238 N. 2200 W.

Salt Lake City, UT 84116

ATTN: Rob Hartman

Prepared by:

Todd Wetzel – Managing Consultant

GeoStrata LLC

14425 S. Center Point Way

Bluffdale, Utah 84065

(801) 501-0583

August 2020

Table of Contents

List of Tables

1. EXECUTIVE SUMMARY

US Magnesium, LLC (USM) owns and operates the Rowley Plant, a primary magnesium production facility located in Toole County, Utah. In a letter dated October 21, 2019[1] sent to USM by UDAQ it requested a four-factor Best Available Retrofit Technology (BART) analysis of USM's Rowley Plant as part of the second planning period for Regional Haze.

The letter determined that PM_{10} is not a significant contributor to visibility, and so no BART analysis was performed for PM_{10}. The letter also stated that USM is a significant source of SO_2 and NO_X. During a follow-up meeting in October of 2019, as well as phone calls in June of 2020, UDAQ determined, with the help of USM's actual annual inventory, that SO_2 emissions from the magnesium plant are not a contributing factor to visibility impairment and as a result no BART analysis was required or performed for SO_2.

The U.S. EPA has issued guidelines in 40 CFR 51.308 that are to be used to evaluate the reduction measures for the emission units at USM's facility. The State must consider the following four factors[2], and include a demonstration showing how these factors were taken into consideration when selecting the goal:

1. The costs of compliance
2. The time necessary for compliance
3. The energy and non-air quality environmental impacts of compliance
4. The remaining useful life of any potentially effected sources

This report documents the results of a four-factor BART analysis for NO_X emissions facility wide. It is intended to provide information to UDAQ and the Western Regional Air Partnership (WRAP) for the purposes of the second planning period of the Regional Haze SIP.

USM has multiple NO_X emitting units on site, all a result of fuel combustion, that UDAQ has identified as contributing to regional haze. The results of the four-factor BART analysis determined that one retrofit control option is feasible for installation at USM's facility, a flue gas recirculation (FGR) system on their Riley Boiler. The estimated NO_X reduction from the FGR system is 22.6 tons annually. The installation of the control device could potentially be performed prior to the end of the second planning phase for regional haze, 2028, although additional evaluation will be necessary.

A summary of the NO_X emission reduction measures and findings can be found below in Table 1-1.

[1] Refer to UDAQ letter DAQP-183-19
[2] 40 CFR 51.308

Table 1-1: Summary of Findings

Emission Source	Emission Reduction Measure	Technically Feasible?	Cost Effective?	Appropriate for Emissions Reductions?	Notes
Turbines & Duct Burners	Water or Steam Injection	No	NA	No	USM utilizes the exhaust from the Turbines, amplifying the temperature using the duct burners, in their spray dryers to create dry magnesium chloride the starting material for magnesium production at their plant. Any modifications to combustion or post combustion temperature directly impact product development and are therefore not feasible.
	Dry Low-NO_X	No	NA	No	
	Selective Catalytic Reduction (SCR)	No	NA	No	
Chlorine Reduction Burner	NA	NA	NA	NA	The CRB is a control device for chlorine emissions and is required to operate within a specific temperature range for efficient destruction of chlorine. No control techniques or devices exist to control NO_X emissions from this source.
Riley Boiler	Flue Gas Recirculation (FGR)	Yes	Yes	Yes	A potentially viable option for controlling an estimated 22.6 tons of NO_X annually. Installation of an FGR may be feasible by the end of 2028.
	Low NO_X Burners	No	NA	No	Limited space constraints for the current setup at USM make this option not feasible.
	Ultra-Low NO_X Burners	No	NA	No	Limited space constraints for the current setup at USM make this option not feasible.
	Selective Catalytic Reduction (SCR)	Yes	No	No	The costs associated with this control device made this option not cost effective.
	Selective Non-Catalytic Reduction (SNCR)	No	NA	No	The 1972 boiler currently installed at USM does not reach and maintain the temperatures required for an SNCR device.
Diesel Engines	Exhaust Gas Recirculation (EGR)	Yes	No	No	The cost to implement EGR on the 31 diesel engines does not justify the reduction in emissions associated with each engine.

Emission Source	Emission Reduction Measure	Technically Feasible?	Cost Effective?	Appropriate for Emissions Reductions?	Notes
	Selective Catalytic Reduction (SCR)	Yes	No	No	The cost to retrofit each engine with an SCR unit and the accompanying space required is not economically feasible.
	Lean NO_X Catalysts	No	NA	No	Lean NO_X catalysts are relatively new emission control devices, a thorough search of the available databases found no instances where they are in use.
HCl Plant	Water or Steam Injection	No	NA	No	The reduction in peak flame temperature associated with water or steam injection would impede the production of HCl, and alter the function of the HCl Plant, it is therefore not technically feasible.
	Dry Low-NO_X	No	NA	No	The reduction in peak flame temperature associated staged combustion or by modifying fuel-air ratios would impede the production of HCl, and alter the function of the HCl Plant, it is therefore not technically feasible.
	Selective Catalytic Reduction (SCR)	No	NA	No	A RBLC search found one facility that has implemented SCR on a HCl plant as LAER. The variable run times and associated operating temperatures make operating a SCR unit a challenge as the HCl Plant and its operation was not designed for one, a retrofit option was determined to not be technically feasible.
Casting House	NA	NA	NA	NA	No retrofit control strategies or devices were identified for the small burners utilized in the casting house at USM.
Lithium Plant	Low NO_X Burners	Yes	Yes	Yes	Currently equipped on the evaporative burners at USM. They were determined to be BACT in 2020 as part of their most recent permit modification.
	Ultra-Low NO_X Burners	Yes	Yes	Yes	Currently equipped on the new boilers at USM. They were determined to be BACT in 2020 as part of their most recent permit modification.

2. INTRODUCTION AND BACKGROUND

The Clean Air Act (CAA) has made it a national goal to restore national parks and wilderness areas back to natural conditions by reducing and correcting visibility impairments from man-made sources that result in pollution called regional haze. The EPA defines "regional haze" in 40 CFR 51.301 as "visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." The pollutants responsible for the decrease in visibility are particulate and gaseous emissions from sources, they absorb light and as a result negatively impact visibility.

The 1977 amendments to the CAA established Class I areas under the Prevention of Significant Deterioration (PSD) program, and defined them as, "national wilderness areas, and national memorial parks that exceed 5,000 acres, and all national parks that exceed 6,000 acres." Five National Parks located in Utah are listed as Class I areas Arches, Bryce Canyon, Canyonlands, Capitol Reef, and Zion. In 1999 the EPA promulgated the Regional Haze Rule (RHR). The RHR established guidelines that would work to restore visibility to the 156 Class I areas nationwide.

The RHR requires States to establish reasonable progress goals towards achieving natural visibility conditions for the Class I areas located within the State. The State is required to meet the specific requirements listed in 40 CFR 51.308(d)(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.

(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 measures needed to achieve it for the period covered by the implementation plan.

With this being the second implementation period, the State and the EPA will attempt to distinguish between natural and anthropogenic sources. This will be done utilizing modelling to establish what background concentrations are, both episodic and routine in nature and compare those background levels against the man-made source contributions.

UDAQ has requested that US Magnesium conduct a four-factor analysis for second phase of the regional haze program for its Rowley Plant. US Magnesium understands that the information provided within this document will be used by UDAQ in their evaluation of reasonable progress goals. Similarly, US Magnesium assumes that emission reductions will only be required if the reductions demonstrate reasonable progress towards improved visibility in one or more of the Class I areas located within the state within the period covered by the implementation plan.

The purpose of this report is to provide UDAQ with information on available retrofit technologies for NO_X emission reductions at US Magnesium's Rowley Plant.

The four-factors that are evaluated in this report for emission reductions are:

1. Cost of compliance
2. Time necessary for compliance
3. Energy and non-air quality environmental impacts of compliance
4. Remaining useful life of the Emission Units

This report summarizes a top down BART analysis for all applicable emission units, following the provisions published in 40 CFR Part 51, Section 308 in July of 2005. The top down BART analysis consists of the following steps:

Step 1 – Identify all potentially available retrofit control technologies
Step 2 – Eliminate technically infeasible options
Step 3 – Rank remaining control technologies by control effectiveness
Step 4 – Evaluate most effective controls and document conclusions

This four-step process will satisfy the requirements of the four-factor analysis, as factor 4 and similarly factor 2 will be addressed in the cost of emission reduction options.

3. SOURCE DESCRIPTION

US Magnesium's (USM) Rowley Plant is located within Tooele County, Utah. The five Class I areas are located the following distances from their facility:

Arches National Park – 225 miles
Bryce Canyon National Park – 230 miles
Canyonlands National Park – 235 miles
Capitol Reef National Park – 193 miles
Zion National Park – 250 miles

USM operates a primary magnesium production facility that began operation in 1972. They produce magnesium metal from the waters of the Great Salt Lake. Some of the water is evaporated in a system of solar evaporation ponds to increase the magnesium concentration and the resulting brine solution is then purified and dried to a powder in one of three natural gas fired spray dryers. The powder is then melted and further purified in the melt reactor before going through an electrolytic process to separate magnesium metal from chlorine. The metal is then refined or alloyed and cast into molds. The chlorine from the melt reactor is combusted with natural gas in the chlorine reduction burner (CRB) and converted into hydrochloric acid (HCl). The HCl is removed from the gas stream through a scrubber train. The chlorine that is generated at the electrolytic cells is collected and piped to the chlorine plant where it is liquefied for reuse or sale. USM also produces other minerals and chemicals for sale as a byproduct of magnesium production, lithium carbonate and food grade HCl acid.

USM operates a wide array of equipment that produces PM, NO_X, and SO_2. This equipment ranges from diesel-fueled engines to natural gas fired equipment such as boilers, burners, furnaces, turbines. The PM producing equipment includes the spray dryers and emergency off-gas stack. The equipment that can be found in the subsequent section is the relevant equipment that emits pollutants of concern for the purposes of this four-factor analysis.

USM also operates mobile equipment that facilitate various operations on site and movement of material. These emissions will not be included in this four-factor analysis as they constitute a very small portion of the overall NO_X emissions and USM maximizes efficiencies on product loads and vehicle miles traveled to reduce operating costs.

3.1. EQUIPMENT DESCRIPTION

The following subsections describe the equipment utilized by USM to generate their final products for sale.

3.1.1. Natural Gas Turbines | Duct Burners - (Spray Dryers)

Three 12,700 KW natural gas fired turbines are utilized for onsite electrical generation. The exhaust stream of each turbine is equipped with an additional 15.3 MMBtu/hr duct burner to increase the temperature of the exhaust gas from the turbines for use in the spray dryers. The spray dryers utilize the heated exhaust to dry the concentrated brine solution into a magnesium chloride powder utilizing one of three identical spray dryers.

3.1.2. Emergency Off-gas Stack

The emergency off-gas (EOG) scrubber stack is a pollutant source for PM_{10}. The EOG system is primarily operated to collect fugitive emissions within the melt/reactor building as part of USM's industrial hygiene/worker safety program.

3.1.3. Chlorine Reduction Burner

The chlorine reduction burner (CRB) is the control device that reduces (reacts) chlorine gas from the melt/reactor process with natural gas (CH4) to produce hydrogen chloride gas which is recovered as hydrochloric acid (liquid) for use in other areas of USM's production processes. The CRB has a minimum firing rating of 1 MMBtu/hr and a maximum fire rating of 42 MMBtu/hr. The CRB controls most of the chlorine emissions from the facility and utilizes only natural gas as a fuel source. An operating temperature of 1,650 to 2,000 degrees Fahrenheit is maintained to achieve the necessary reaction of chlorine gas within the combustion zone, the typical fire rating for the required temperature is 20 MMBtu/hr.

3.1.4. Riley Boiler

The Riley Boiler is a 60 MMBtu/hr boiler that was installed when the plant was first constructed in 1972. The boiler provides heat through the production of steam for operations throughout the site.

3.1.5. Diesel-fired Engines

USM utilizes two main sizes of diesel-fired engines to power the direct drive pumps. These pumps move water around the solar evaporation pond system to increase the magnesium chloride concentration in the brine until the brine is eventually pumped to the processing facility. USM utilizes the following engines onsite, all of which are compliant with NESHAP 40 CFR 63 Subpart ZZZZ:

- 14 - Caterpillar 3406 (420 hp)
- 13 – Caterpillar 3208 (225 hp)
- 1 – Cummings C-9 (285 hp)
- 1 – Caterpillar 3306 (225 hp)
- 1 – Caterpillar 3304 (90 hp)
- 1 – 292 hp fire pump engine

All engines are retrofit with an EST Oxidation Converter, a packed catalyst system, for the reduction of CO and PM emissions.

3.1.6. Hydrochloric Acid Plant

The plant produces food grade hydrochloric acid by reducing purified chlorine in a natural gas flame to produce hydrogen chloride gas. The gas passes through a series of absorbers to produce the food grade hydrochloric acid.

3.1.7. Cast House

USM operates eleven natural gas fired crucible furnaces, each crucible furnace contains six individual 1 MMBtu/hr burners, in the cast house. The cast house also utilizes bayonet burners in tool heating boxes, the heating boxes are necessary for site safety. The tools are heated to remove any water condensation from the tools and bring them up to a working temperature to eliminate the risk of explosion when working with magnesium metal. The cast house is also equipped with a natural gas fired anode oven for magnesium purification.

3.1.8. Lithium Carbonate Plant

The lithium carbonate plant separates lithium from electrolytic process sludge (also referred to as "smut") in a series of digester units, soda ash contact ("demag") units, filter presses, a dryer/classifier and packaging system. Emission units consist of several natural gas fired pieces of equipment. Two natural gas fired ultra-low NO_X boilers, a 63 MMBtu/hr and 84 MMBtu/hr unit and two low-NO_X natural gas fired evaporator burners, a 50 MMBtu/hr and 100 MMBtu/hr unit.

3.1.9. Other Sources

A small propane heater is utilized at the south pumping station. It does not operate full time and has a minimal impact on overall NO_X emissions. This emission source is included here and the emissions tables, but no analysis was performed.

3.1.10. Mobile Sources

Emissions from mobile sources on site come from diesel and propane consumption. The mobile sources include equipment like trucks, track hoes, bulldozers, cranes, skid loaders, and forklifts. The sources are responsible for product development, product handling, and various other site operations. These emission sources were included in the equipment and emission sections for completeness, but as they are not stationary sources no further analysis was performed.

4. BASELINE EMISSIONS

This section summarizes the baseline emission rates that are used as a starting point for the accompanying four-factor analysis presented in section 5. Specifically, they are used in the cost effectiveness analysis to determine the annual cost per ton of pollutant removed for a specific control device or strategy.

4.1. PM_{10} EMISSIONS

USM has provided the following emissions information for PM_{10}. The emissions represent actual emissions at their facility for the 2018 calendar year and are based on a combination of actual fuel use, stack testing, operational hours, or production rates. The Lithium Plant was permitted in 2020 and actual emissions are not yet available, for this reason potential to emit totals were included in the table below for this plant's emissions instead of actuals. The baseline annual emission rates that will be used for the purposes of this analysis are summarized below in Table 4-1.

Table 4-1: Annual PM_{10} Baseline Actual Emission Rates (tons/yr)

Equipment	PM10 Baseline Emissions (tons/yr)
Turbines | Duct Burners	921.06
Emergency Off-gas Stack	43.42
Chlorine Reduction Burner	3.29
Riley Boiler	1.81
Diesel Engines	1.28
HCl Plant	0.33
Cast House	1.12
Lithium Plant	11.64*
Other Sources	4.42
Mobile Sources	4.83
Total	993.21

*Lithium Plant emissions are listed as PTE emissions, as it was not in operation in 2018.

UDAQ has made the decision that the deciview impacts at the five National Parks within Utah are not significantly impacted by point source particulate matter emissions. USM acknowledges that they are a major source for PM_{10} but agrees with UDAQ's assessment, the low dispersion rate for particulate matter makes its negative impact on visibility at the national parks the least likely contributor. As a result, no further analysis or discussion was performed for PM_{10} emissions within this document.

4.2. SO_2 EMISSIONS

USM has provided the following emissions information for SO_2. The emissions represent actual emissions at their facility for the 2018 calendar year and are based on a combination of actual fuel use, stack testing, operational hours, or production rates. The Lithium Plant was permitted in 2020 and actual emissions are not yet available, for this reason potential to emit totals were included in the table below for this plant's emissions instead of actuals. The baseline annual emission rates that will be used for the purposes of this analysis are summarized below in Table 4-2.

Table 4-2: Annual SO_2 Baseline Actual Emission Rates (tons/yr)

Equipment	SO2 Baseline Emissions (tons/yr)
Turbines | Duct Burners	1.66
Chlorine Reduction Burner	0.07
Riley Boiler	0.14
Diesel Engines	0.03
HCl Plant	0.03
Cast House	7.29
Lithium Plant	0.75*
Other Sources	0.06
Mobile Sources	0.05
Total	10.08

*Lithium Plant emissions are listed as PTE emissions, as it was not in operation in 2018.

Due to the insignificant amount of sulfur dioxide emissions coming from USM, a decision was made in the fall of 2019 during a meeting with UDAQ to omit sulfur dioxide from the upcoming BART analysis. Any reductions in SO_2 would not result in any reasonable progress goals and would also likely be cost prohibitive given the minimal impacts of additional controls. No further discussion or analysis was performed for SO_2.

4.3. NO_X EMISSIONS

USM has provided the following emissions information for NO_X. The emissions represent actual emissions at their facility for the 2018 calendar year and are based on a combination of actual fuel use, stack testing, operational hours, or production rates. The Lithium Plant was permitted in 2020 and actual emissions are not yet available, for this reason potential to emit totals were included in the table below for this plant's emissions instead of actuals. The baseline annual emission rates that will be used for the purposes of this analysis are summarized below in Table 4-3.

Table 4-3: Annual NO_X Baseline Actual Emission Rates (tons/yr)

Equipment	NO_X Baseline Emissions (tons/yr)
Turbines | Duct Burners	813.58
Chlorine Reduction Burner	11.66
Riley Boiler	45.25
Diesel Engines	71.65
HCl Plant	4.32
Casting House	14.70
Lithium Plant	26.61*
Other Sources	0.02
Mobile Sources	73.01
Total	1,060.79

*Lithium Plant emissions are listed as PTE emissions, as it was not in operation in 2018.

The values listed above will be utilized in determining actual reductions to emissions because of any additional retrofit control technology. The same assumptions of operation that were employed to calculate annual emissions in 2018 will be employed to determine any reductions from add-on equipment because of the ensuing BART analysis.

5. NO_X FOUR-FACTOR ANALYSIS

The four-factor analysis was completed using a top-down approach, using the following four steps:

Step 1 – Identify all potentially available retrofit control technologies
Step 2 – Eliminate technically infeasible options
Step 3 – Rank remaining control technologies by control effectiveness
Step 4 – Evaluate most effective controls and document conclusions

All four factors of the analysis will be touched on in step four of the above approach. The most effective controls will be represented in a cost per ton removed evaluation, satisfying factor 1, (costs of compliance) and factor 4 (remaining useful life of equipment). Factor 2, (time necessary for compliance) will be included in the conclusions section. Factor 3 (energy and non-air quality environmental impacts of compliance) will be satisfied in steps 2 and 3 of the above approach.

The following four-factor analysis was performed for the NO_X emission units listed in Table 4.3 and utilizing the emission rates included within.

All the NO_X generated at USM is a result of the fuel combustion process. Two primary formation mechanisms are responsible, thermal NO_X, when atmospheric nitrogen and oxygen disassociate in the combustion zone and form NO_X, or fuel NO_X when nitrogen present in the fuel interacts with atmospheric oxygen in the combustion zone. USM utilizes natural gas as a fuel source except during times of curtailment, natural gas and diesel have little to no nitrogen content resulting in the majority of NO_X formation being thermal in origin.

Control strategies for NO_X formation fall into one of two categories, combustion controls or post-combustion controls. Combustion control technologies focus on reducing the peak flame temperature and excess air in the combustion zone resulting in reduced NO_X formation. Post-combustion controls focus on reducing NO_X after it has formed in the exhaust stream usually by utilizing a catalyst.

5.1. TURBINES AND DUCT BURNERS

5.1.1. Step 1: Identify All Potentially Available Retrofit NO_X Control Technologies

The turbines at USM are utilized for electrical generation as an integrated part of the production process. The exhaust from the turbines is routed to a duct burner to increase the temperature before being routed to a spray dryer. The heated exhaust is used to dry the magnesium chloride slurry into a magnesium chloride powder. For the spray dryer to work properly the inlet temperature of the exhaust steam needs to reach 1,000 °F. The exhaust temperature from the turbines is 900 °F, and the duct burners boost the temperature to 1,000 °F.

The duct burners take the exhaust from the turbines and continue to heat it to the desired temperature. NO_X control strategies for this type of equipment does not exist, inlet temperatures and exit temperatures prohibit the use of combustion controls, and post combustion controls are similarly prohibitive, as exhaust temperatures need to reach 1,000 °F. The duct burners emissions are incorporated with the turbines emissions and were included here for completeness. However, since no NO_X control strategies exist for the duct burners at USM, given their utilization, no further analysis was performed for them.

Common control technologies for reduction of NO_X emissions in natural gas turbines, identified by the EPA[3], are listed in Table 5-1 below.

Table 5-1: Available Retrofit NO_X Control Technologies for Combustion Turbines

Combustion Turbines NO_X Control Technologies	
Combustion Controls	Water or Steam Injection
	Dry Low-NO_X
Post-Combustion Controls	Selective Catalytic Reduction (SCR)

5.1.1.1. Combustion Controls

5.1.1.1.1. Water or Steam Injection

Water and or steam injection is commonly termed wet control for gas turbines. Steam or water injection controls the formation of NO_X emissions by decreasing the peak flame temperature. It is an effective tool for reducing the formation of thermal NO_X in all but regenerative cycle combustors.

Evaporation of the water reduces the cycle efficiency of a few percent but increases power output by double that reduction. This is caused by the steam formed or injected in the combustor raising the mass flow rate through the turbine therefore increasing power.

NO_X emission reductions of generally 60-70% can be achieved using water or steam injection at water-to-fuel ratios of 0.2:1 to 1:1. It is important to utilize water or steam free of contaminants, so a water treatment system is an integral component of a wet control system.

Several mechanical limits exist when it comes to water or steam injection systems. Some examples of this are combustion operating instabilities, increased CO, heat rate penalties, combustion flame blow-off or flame-out. These limitations can decrease the efficiency of the water or steam injection system and increase the maintenance required on the turbine.

5.1.1.1.2. Dry Low-NO_X

NO_X emission control techniques that are performed in without the injection of water or steam are referred to as dry controls, but the method for emissions reductions is the same, reducing the peak flame temperature. This is generally accomplished by lean combustion or staged combustion.

Lean combustion refers to a technique that reduces the air/fuel ratio beyond that of normal stoichiometric operation (equivalence ratio = 1) to an air/fuel equivalence ratio of 2, i.e. very lean. This reduces the combustion temperature by reducing the air required for combustion below

[3] U.S. Environmental Protection Agency. (1993). *Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines.* North Carolina: Office of Air Quality Planning and Standards.

stoichiometric levels. This method is only achievable under normal load range, during periods of startup or low load a transition program with higher air/fuel ratios is required. This results in increased NO_X emissions during periods of startup or low load situations.

Staged combustion is another technique to lower NO_X emissions, this strategy utilizes multiple combustion zones, usually two. The first zone operates lean or rich, but the second zone always operates lean. The incomplete combustion that results in the first combustions zone is further combusted in the lean second combustion zone resulting in reduced NO_X formation.

5.1.1.2. Post-Combustion Controls

5.1.1.2.1. Selective Catalytic Reduction (SCR)

In the SCR process, ammonia is injected in the gas turbines exhaust gas stream reacting with NO_X in the presence of a catalyst to form molecular nitrogen and water. SCR works best in base loaded combined cycle gas turbine applications where the turbine is fueled with natural gas. SCR is capable of NO_X removal efficiencies between 70% and 90%. The catalytic NO_X-ammonia reaction takes place over a limited temperature range, 600-750 °F, anything about ~850 °F and the catalyst is damaged irreversibly. Ammonia slip is also a concern when utilizing an SCR for NO_X emission reductions, as well as ammonia storage, and costs of disposal of spent catalysts.

5.1.2. Step 2: Eliminate Technically Infeasible Options

To evaluate if the above NO_X controls are technically feasible it is important to understand the role of the turbines at USM. The turbines are utilized for electrical generation and are integral to the production process. The exhaust coupled with a duct burner is used in a spray dryer to dry the magnesium chloride slurry into a magnesium chloride powder. For the spray dryer to work properly the exhaust temperature of turbines needs to reach 1,000 °F. This is achieved by utilizing an inline duct burner to boost the temperature from 900 °F to 1,000 °F. The magnesium chloride powder is then sent to the melt reactor for further processing.

Taking these operational constraints into consideration, step 2 of the top-down review can be completed.

5.1.2.1. Combustion Controls

Combustion controls focus on reducing the peak flame temperature in the combustion zone of the turbine, therefore reducing thermal NO_X formation. Given that the parameters required for drying the magnesium chloride brine both options are directly conflict with the need for 1,000 °F exhaust temperatures.

5.1.2.1.1. Water or Steam Injection

This control technology given its strategy for reducing peak flame temperature is adding water to the combustion zone directly conflicts with the magnesium chloride powder production. Moisture in the exhaust stream will most definitely affect the ability of the spray dryers to operate as designed. This method is considered technically infeasible given the operational requirements of the spray dryers and will not be considered further.

5.1.2.1.2. Dry Low-NO_X

Reducing peak flame temperatures and lowering the temperature of the exhaust gas would require a larger duct burner be installed. A larger duct burner would create just as much NO_X as the reduction, possibly more. For this reason both the lean combustion and staged combustion methods are considered technically infeasible, as the operational requirements for the spray dryers would be negatively impacted to a point where they would conflict with the production of magnesium product, as a result this will not be considered further.

5.1.2.2. Post Combustion Controls

5.1.2.2.1. Selective Catalytic Reduction (SCR)

An SCR system requires a specific operating temperature to be effective at NO_X removal, that temperature hovers around 750 °F. The duct burners take the exhaust from the turbines at roughly 900 °F and heat it to 1,000 °F. An SCR system is not technically feasible at these operating temperatures and will not be considered further in this analysis.

5.1.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 of the review process is to rank the technically feasible options by how effective they are at removing NO_X emissions. As no control technologies are technically feasible for the specific operations at USM, no ranking is possible.

5.1.4. Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

As no remaining retrofit control technologies are technically feasible, analysis of the above list is not possible.

5.1.4.1. Summary and Conclusions

USM requires specific temperatures from their exhaust stream for their proper operation of the spray dryers, any changes to the turbine or duct burners would require significant alterations to the spray dryers. The turbines and duct burners, in 2018, emitted 813.58 tons of NO_X emissions. Although this is a significant source of NO_X emissions, no technically feasible retrofit technologies were found during the BART analysis. USM will continue to operate the turbines and duct burners as they are currently configured.

5.2. CHLORINE REDUCTION BURNER

5.2.1. Step 1: Identify All Potentially Available Retrofit NO_X Control Technologies

USM operates the only primary magnesium metal production facility in the United States. As such it is the only facility that operates a chlorine reduction burner (CRB) in the United States. The CRB is a control device for chlorine gas emissions. It is designed to take the chlorine gas that is generated in the melt reactor process and as tail-gas from the chlorine (purification) plant, and in the presence of heat and methane, produce CO2 and hydrochloric acid (HCl). The HCl is scrubbed and recovered as hydrochloric acid liquid prior to the exhaust stream being further scrubbed and then vented to the atmosphere.

Combustion techniques that lower the formation of thermal NO_X by lowering the peak flame temperature are not a viable option for control as they would impact the CRB's main function of reducing the chlorine emissions that are emitted to the atmosphere. The CRB requires an operating temperature of no less than 1,650 °F and no more than 2,000 °F for proper operation and has strict monitoring requirements listed in their Title V operating permit[4].

Post-combustion techniques involving a catalyst would foul the packed scrubbers that remove the HCl acid from the exhaust stream, which could violate the emission requirements found in 40 CFR 63 Subpart TTTTT[5].

Given the unique operating parameters involved in the CRB no control technologies exist for the reduction of NO_X emissions. Therefore, no additional analysis was performed for the CRB.

5.2.2. Step 2: Eliminate Technically Infeasible Options

No NO_X emission reduction retrofit controls are available for the CRB.

5.2.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 of the review process is to rank the technically feasible options by how effective they are at removing NO_X emissions. As no control technologies are technically feasible for the specific operations at USM, no ranking is possible.

5.2.4. Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality

[4] See UDAQ Title V Operating Permit #4500030003 dated December 12, 2018.
[5] 40 CFR 63 Appendix Table 1 to Subpart TTTTT of Part 63 – Emission Limits

- The remaining useful life of the source

As no remaining retrofit control technologies are technically feasible, analysis of the above list is not possible.

5.1.4.1. Summary and Conclusions

The CRB at USM is required to maintain an operating temperature of 1,650 to 2,000 °F, and as such combustion controls are not a viable option for controlling the formation of thermal NO_X. Post-combustion controls are similarly disadvantageous, and the exhaust stream from the CRB passes through an absorber to recover HCL as hydrochloric acid liquid and then several packed bed scrubbers to remove PM. The addition of any catalyst to remove NO_X emissions could interfere with the scrubber's operation and result in emissions that violate the emissions standards that are listed in the appliable MACT, Subpart TTTTT. The CRB at USM currently emits 11.66 tons of NO_X annually. USM will continue to operate the CRB as it is currently configured.

5.3. RILEY BOILER

5.3.1. Step 1: Identify All Potentially Available Retrofit NO_X Control Technologies

USM utilizes a 60 MMBtu/hr boiler, referred to as the Riley boiler that was first installed prior to the plant beginning operation in 1972. The boiler utilizes natural gas as a combustion source and provides heat throughout the plant via the production of steam. The boiler is located in the middle of their facility, nestled between scrubbers, spray dryers, and various other equipment.

Common NO_X control strategies for a natural gas boiler are listed below in Table 5-2. The RBLC of the EPA Clean Air Technology Center as well as EPA's, "Nitrogen Oxides (NO_X), Why and How They are Controlled"[6] were utilized in determining control technologies for evaluation.

Table 5-2: Available Retrofit NO_X Control Technologies for Combustion Turbines

Boiler NO_X Control Technologies	
Combustion Controls	Flue Gas Recirculation (FGR)
	Low NO_X Burners
	Ultra-Low NO_X Burners
Post-Combustion Controls	Selective Catalytic Reduction (SCR)
	Selective Non-Catalytic Reduction (SNCR)

5.3.1.1. Combustion Controls

5.3.1.1.1. Flue Gas Recirculation (FGR)

Flue gas recirculation consists of recirculating a portion of the flue gas to the combustion zone to lower the peak flame temperature and lowers the percentage of oxygen in the combustion zone, thereby reducing thermal NO_X formation. FGR is one of the main NO_X reduction strategies for

[6] U.S. EPA. (1999). *Nitrogen Oxides (NOx), Why and How They Are Controlled.* North Carolina: U.S. Environmental Protection Agency.

low NO_X and ultra-low NO_X burners. Standalone FGR systems can achieve up to 50% NO_X reductions.[7]

5.3.1.1.2. Low NO_X burners

Low NO_X burners reduce the formation of thermal NO_X by utilizing multiple technologies coupled with staged combustion. Many variations of a low NO_X burner exist, almost all of them utilizing staged combustion for controlling fuel to air ratios to limit the peak flame temperature. Controlling fuel and air mixing at the burner creates larger and more branching flames, making low NO_X burners have a larger footprint than a standard boiler like the one installed at USM. Low NO_X burners can reduce NO_X emissions by up to 80% from a standard combustion unit and are considered common place and often the starting point of new boiler installations.

5.3.1.1.3. Ultra-Low NO_X burners

Ultra-Low NO_X burners improve upon the design of a low NO_X burner usually by lowering combustion temperatures even more by modifying the burners further. The lower temperatures require larger volumes of fuel as the combustion process is not complete, this also increases CO emissions while reducing NO_X emissions. Depending on the provider of the ultra-low unit, technology varies but they are generally capable of meeting NO_X emission limits of 9 ppm.

5.3.1.2. Post-Combustion Controls

5.3.1.2.1. Selective Catalytic Reduction (SCR)

In the SCR process, ammonia is injected into the exhaust stream reacting with NO_X in the presence of a catalyst to form molecular nitrogen and water. SCR works best in stable conditions, units that fluctuate in operation and therefore temperature do not achieve optimal NO_X reduction rates. SCR is capable of NO_X removal efficiencies between 80% and 90%[8]. The catalytic NO_X-ammonia reaction takes place over a limited temperature range, 600-750 °F, anything about ~850 °F and the catalyst is damaged irreversibly. Ammonia slip is also a concern when utilizing an SCR for NO_X emission reductions, as well as ammonia storage, and costs of disposal of spent catalysts.

5.3.1.2.2. Selective Non-Catalytic Reduction (SNCR)

SNCR is a similar process to SCR in that it utilizes ammonia as a reductant to reduce NO_X compounds to molecular N_2 and water, however the technology does not utilize a catalyst. The ammonia in injected directly into the primary combustion zone where temperatures reach 1,400-2,000 °F. NO_X reduction in SNCR is only effective at high temperatures (1,600-2,100 °F), so additional heating of the emissions stream may be required to meet optimal operating temperatures. SNCR NO_X removal efficiencies vary between 30% and 50%.

[7] CDP. (2020, July 27). *ICIBSE Journal.* Retrieved from Module 106: Natural gas boiler flue gas recirculation to reduce NOx emissions: https://www.cibsejournal.com/cpd/modules/2016-12-nox/

[8] Ron D. Bell. (2020, July 22). *An Overview of Technologies for Reduction of Oxides of Nitrogen From Combustion Furnaces.* Retrieved from MPR: https://www.mpr.com/uploads/news/nox-reduction-coal-fired.pdf

5.3.2. Step 2: Eliminate Technically Infeasible Options

5.3.2.1. Combustion Controls

5.3.2.1.1. Flue Gas Recirculation (FGR)

FGR increases the maintenance required and can result in fouled air intake systems, combustion chamber deposits, and increased wear rates, but it is technically feasible as a retrofit option.

5.3.2.1.2. Low NO_X Burners

To convert the standard burners currently installed in the Riley boiler, to low NO_X burners would require substantial modifications and would not really fit the definition of a retrofit. The additional space requirement due to the staged combustion a low NO_X unit requires would be challenging to fit into the existing space. This would require modifications to other systems to accommodate the additional size, and as a result has been ruled out as a technically feasible option. The low NO_X burners have been ruled out as a retrofit option and was not evaluated further.

5.3.2.1.3. Ultra-Low NO_X Burners

An ultra-low NO_X burner was similarly ruled out as technically feasible as a retrofit option as it would require a near complete replacement of the existing boiler. Additionally, the space requirements would require the same modifications as installing low NO_X burners. The ultra-low NO_X burners have been ruled out as a retrofit option and was not evaluated further.

5.3.2.2. Post-Combustion Controls

5.3.2.2.1. Selective Catalytic Reduction (SCR)

An SCR system is an effective way at reducing NO_X formation in a stationary combustion unit like the boiler utilized at USM. They do present additional safety concerns with the use of ammonia and ammonia storage. An SCR system is considered a technically feasible retrofit option for the boiler.

5.3.2.2.2. Selective Non-Catalytic Reduction (SNCR)

The boiler at USM was built in the 1970's and has had general maintenance and replacement of some of the burner units and housing as it has aged but is largely unchanged. The required operating temperatures for an SNCR system to work properly (1,600 – 2,000 °F) are not within the boilers operating range. As a result, a SNCR system has been ruled out as a retrofit option for the Riley boiler, and was not evaluated further.

5.3.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 is the ranking of the remaining commonly available retrofit control technologies by control effectiveness. Table 5-3 below ranks those remaining retrofit control technologies by their respective control effectiveness at reducing NO_X emissions.

Table 5-3: Remaining Retrofit NO_X Control Technologies by Control Effectiveness

NO_X Control Technologies	NO_X Control Reductions
Selective Catalytic Reduction (SCR)	Up to 90%
Flue Gas Recirculation (FGR)	Up to 50%

5.3.4. Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

5.3.4.1. Cost of Compliance

The Riley boiler operating at USM was installed in 1972 and has no addon equipment. The cost analysis below is based on the baseline emissions calculated using AP-42 and a full-time operating schedule, generating 45.25 tons of NO_X annually.

5.3.4.1.1. Selective Catalytic Reduction (SCR)

Evaluating the costs for an SCR unit on an existing boiler of this small size is challenging. The EPA's Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction (SCR) was used to estimate the costs of retrofitting the boiler[9]; the cost values are based on the 2018 annual average Chemical Engineering Plant Cost Index (CEPCI) value of 603.1. The summary of the results are listed below in Table 5-4, with the detailed cost results found in Appendix A.

[9] The detailed inputs and outputs of the EPA cost estimation tool can be found in Appendix A.

Table 5-4: Summary SCR Retrofit Costs for Riley Boiler

CAPITAL COSTS				
Direct Costs			**Indirect Annual Costs**	
SCR System	$86,684		Administrative Charges	$2,716
			Capital Recovery Costs	$279,930
Total	$86,684		**Total**	$282,646
ANNUAL COSTS			**Totals**	
Direct Costs			Interest rate	7.00%
Maintenance	$16,311		CRF	0.0858
Annual Reagent Cost	$48,399		Life of Control (yrs)	25
Annual Electricity Cost	$17,910		Total Capital Investments	$3,262,190
Annual Catalyst Replacement Cost	$4,064		Total Annual Costs	$369,330
Total	$70,373		Total Annual Cost	**$369,330.00***

*Reported in 2018 dollars

EPA's cost estimating tool, based on the default parameters of an SCR unit, determined that a unit would reduce NO_X emissions by an estimated 38 tons annually. The cost effectiveness based on 2018 dollars is listed in Table 5-5 below.

Table 5-5: SCR Retrofit Cost Effectiveness for Riley Boiler

	Total Annual Cost ($/yr)	Control Efficiency	NO_X Emissions Reduction	Cost Effectiveness ($/ton removed)
SCR Costs	$369,330	90%	38	$9,726*

*Reported in 2018 dollars

The costs associated with installing an SCR system on a boiler of this age would be not be considered economically feasible. As a result, the use of an SCR system for NO_X control has been ruled out as a viable retrofit option for NO_X control.

5.3.4.1.2. Flue Gas Recirculation (FGR)

The cost analysis for a FGR system on an existing boiler needs to be done by specific vendors and engineered for the specific boiler, especially for older units like the one at USM's facility. However, general cost guidelines can be used to estimate the costs for an appropriate FGR system. A general cost for an FGR system is somewhere in the range of $8-35/kW, in specific cases some can be as low as $3/kW.[10] This would put the cost range of an addon FGR for the 60 MMBtu/hr Riley boiler somewhere between $52,740 and $615,300.

[10] Frederick, N., Agrawal, R. K., & Wood, S. C. (2020, August 3). *NOx control on a Budget: Induced Flue Gas Recirculation.* Retrieved from Power Engineering: https://www.power-eng.com/2003/07/01/nosubx-sub-control-on-a-budget-induced-flue-gas-recirculation/#gref

It is important to note that these cost estimates were from EPA studies done in the 1990's, and as such the cost per ton removed analysis was performed using the high end of the range, \$615,300. The cost analysis results can be found below in Table 5-6.

Table 5-6: FGR Retrofit Costs for the Riley Boiler

<table>
<tr><th colspan="5">CAPITAL COSTS</th></tr>
<tr><th colspan="5">Direct Costs</th></tr>
<tr><td colspan="4">FGR System (all inclusive)</td><td>$615,300</td></tr>
<tr><td colspan="4" align="right">Total</td><td>$615,300</td></tr>
<tr><th colspan="2">ANNUAL COSTS</th><td></td><th colspan="2">Totals</th></tr>
<tr><th colspan="2">Direct Costs</th><td></td><td>Interest rate</td><td>7.00%</td></tr>
<tr><td>Maintenance (hrs @ $)</td><td>52 @ $60</td><td></td><td>CRF</td><td>0.0944</td></tr>
<tr><td>Cost of Maintenance hours</td><td>$3,120</td><td></td><td>Life of Control (yrs)</td><td>20</td></tr>
<tr><td></td><td></td><td></td><td>Total Capital Costs</td><td>$615,300</td></tr>
<tr><td></td><td></td><td></td><td>Annualized Capital</td><td>$58,080</td></tr>
<tr><td></td><td></td><td></td><td>Annual Maintenance Cost</td><td>$3,120</td></tr>
<tr><td align="right">Total</td><td>$3,120.00</td><td></td><td align="right">Total Annual Cost</td><td>$61,200</td></tr>
</table>

Assuming a 50% NO_X emissions control efficiency from a FGR system, a reduction of 22.6 tons of NO_X annually would result from the installation. The cost effectiveness based on dollars per ton of NO_X removed is listed below in table 5-7.

Table 5-7: FGR Retrofit Cost Effectiveness for Riley Boiler

	Total Annual Cost (\$/yr)	Control Efficiency	NO_X Emissions Reduction	Cost Effectiveness (\$/ton removed)
FGR System	\$61,200	50%	22.6	\$2,708

Based on the factored cost estimate evaluated, an FGR system may be reasonable given the amount of NO_X control achieved, and the estimated cost per ton removed of \$2,708.

5.4.4.2. Timing for Compliance

Although additional evaluation will be necessary, installation of an FGR system on the Riley boiler may be feasible before the end of 2028, the end of the second long-term strategy for regional haze.

5.4.4.3. Energy and Other Impact Not Related to Air Quality

The biggest concern related to the installation of a FGR system would be the increase in CO that is associated with the decrease in burner efficiency because of incomplete combustion. No other negative impacts are related to energy or other environmental issues.

5.4.4.4. Remaining Useful Life of the Source

The boiler has been well maintained and parts have been replaced over the years. It is reasonable to assume that the boiler will continue to operate for the foreseeable future. Given that the boiler was built and installed in 1972, it is approximately 48 years old, the remaining useful life is speculative, but given proper maintenance and replacement of worn out parts of the boiler its anticipated the boiler will last another 10 to 20 years.

5.4.4.5. Summary and Conclusions

USM has determined that a potentially viable retrofit control technology for NO_X control of the Riley boiler is the installation of an FGR system. The system would reduce NO_X emissions by approximately 22.6 tons, with an estimated cost per ton removed of $2,708. Although additional evaluation will be necessary, USM incorporating this control strategy into the Riley boilers current layout may be feasible before the end of 2028.

5.4. DIESEL ENGINES

5.4.1. Step 1: Identify All Potentially Available Retrofit NO_X Control Technologies

The diesel engines used onsite at USM are mostly comprised of modified Caterpillar engines that run direct drive water pumps for movement of fluids from one evaporation cell to another through various channels and trenches. The diesel engines are the second largest point source category for NO_X emissions, this is due to the number of engines, 31, that are utilized onsite. Of the 31 engines, one is a 292 hp fire pump engine that charges their fire suppression system under emergency conditions (e.g., a plant fire during a power outage). Control technologies for that engine have not been analyzed as part of this analysis, as it is an emergency fire water pump engine that has very minimal run times.

The remaining 30 engines are all equipped with aftermarket catalytic oxidizers to comply with the emission standards listed in 40 CFR 63 Subpart ZZZZ. The engines make and models are listed below:

- 14 - Caterpillar 3406 (420 hp)
- 13 – Caterpillar 3208 (225 hp)
- 1 – Cummings C-9 (285 hp)
- 1 – Caterpillar 3306 (225 hp)
- 1 – Caterpillar 3304 (90 hp)

Although the engines utilized at USM facility consist of different sized motors, the control technologies for NO_X are similar. The following control technologies applicability to the engines was evaluated regardless of engine size, as the only difference will be evaluated in Step 4 when looking at the implementation costs.

Common control technologies for reduction of NO_X emissions in diesel engines have been identified by EPA's Control Techniques Guidelines[11,12] and manufacturers[13,14], and are listed below in Table 5-8.

Table 5-8: Available Retrofit NO_X Control Technologies for Diesel Engine

NO_X Control Technologies	
Combustion Controls	Exhaust Gas Recirculation (EGR)
Post-Combustion Controls	Selective Catalytic Reduction (SCR)
	Lean NO_X Catalysts

5.4.1.1. Combustion Controls

5.4.1.1.1. Exhaust Gas Recirculation (EGR)

Utilizing EGR is an effective method for reducing NO_X emissions from a diesel engine. Low-pressure and high-pressure EGR systems exist but for retrofitting purposes a low-pressure system is almost always utilized as it does not require extensive engine modifications.

EGR recirculates a portion of the engine's exhaust back to the intake manifold, in most cases an intercooler lowers the temperature of the recirculated gases. The cooled recirculated gases, which have a higher heat capacity than air and contain less oxygen than air, lower the combustion temperature of the engine, resulting in less thermal NO_X forming. Diesel particulate filters are required when utilizing a low-pressure EGR system to ensure that large amounts of particulates are not recirculated to the engine. An EGR system can reduce NO_X emissions, by lowering the combustion temperature of the engine, by up to 40%.

5.4.1.2. Post-Combustion Controls

5.4.1.2.1. Selective Catalytic Reduction (SCR)

SCR is an established method for controlling NO_X emissions from stationary sources. A SCR system uses a catalyst and a chemical reductant to convert NO_X emissions to molecular nitrogen and oxygen in oxygen-rich exhaust streams common to diesel engines.

The chemical reductant of choice is generally ammonia and it is injected based on the amount of NO_X present in the exhaust stream that is calculated via algorithm. As the exhaust air and the ammonia pass over the SCR catalyst, a chemical reaction occurs that reduces NO_X emissions to nitrogen and oxygen. SCR systems on stationary sources can control 95% of NO_X emissions.

[11] United States Environmental Protection Agency. (1993, July). Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engines.

[12] *Verified Technologies List for Clean Diesel*. (2017, January 19). Retrieved from United States Environmental Protection Agency: https://www.epa.gov/verified-diesel-tech/verified-technologies-list-clean-diesel

[13] CleanAIR Systems. (2009, December). Emissions Guidebook. Retrieved from: http://www.intermountainelectronics.com/uploads/media/Media_633964831354073381.pdf

[14] *What is Retrofit*. (2020). Retrieved from Manufacturers of Emission Controls Association: http://www.meca.org/diesel-retrofit/what-is-retrofit

5.4.1.2.2. Lean NO_X Catalysts

Diesel engines are designed to run lean, which makes controlling NO_X emissions challenging. Reducing NO_X to molecular nitrogen in the oxygen-rich diesel exhaust environment requires a reductant (typically a hydrocarbon or carbon monoxide) and under normal operating conditions reductants are generally not present.

Lean NO_X catalyst systems typically inject a small amount of diesel fuel or other reductant into the exhaust upstream of the catalyst. The reductant serves as the reducing agent for the catalytic conversion of NO_X to N_2. Some systems operate passively without added reductant reduced NO_X conversion rates. A lean NO_X catalyst consists of a porous material with a highly ordered channel structure, along with either a precious metal or base metal catalyst. The added fuel and the catalyst are capable of peak NO_X control efficiencies ranging from 10 to 30 percent, which the higher control percent correlating to increased fuel injection rates.

5.4.2. Step 2: Eliminate Technically Infeasible Options

5.4.2.1. Combustion Controls

5.4.2.1.1. Exhaust Gas Recirculation (EGR)

Although EGR increases engine maintenance and can result in fouled air intake systems, combustion chamber deposits, and increased engine wear rates, it is technically feasible as a retrofit option.

5.4.2.2. Post-Combustion Controls

5.4.2.2.1. Selective Catalytic Reduction (SCR)

SCR systems are an effective way at reducing NO_X formation, they do present additional safety concerns with the use of ammonia or urea, and ammonia or urea storage. Additionally, the physical footprint of the SCR which can range from 50% to 60% the size of the engine is a real concern. It would likely mean extensive modifications to some of the existing pump stations to accommodate their size. However, given these concerns they remain a technically feasible retrofit option.

5.4.2.2.2. Lean NO_X Catalysts

Lean NO_X Catalysts are a relatively new addition to controlling NO_X emissions. Although in theory they do appear to be technically feasible an extensive search through the RBL Clearinghouse and California's CARB database we were unable to find any stationary engines that utilized this control equipment. Therefore, this will not be considered a technically feasible control option for the diesel engines and will not be evaluated further.

5.4.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 is the ranking of the remaining commonly available retrofit control technologies by control effectiveness. Table 5-9 below ranks those remaining retrofit control technologies by their respective control effectiveness at reducing NO_X emissions.

Table 5-9: Remaining Retrofit NO_X Control Technologies by Control Effectiveness

NO_X Control Technologies	NO_X Control Reductions
Selective Catalytic Reduction (SCR)	Up to 95%
Exhaust Gas Recirculation (EGR)	Up to 40%

5.4.4. Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

5.4.4.1. Cost of Compliance

Currently USM has installed catalytic oxidizers on all the diesel engines to meet the requirements in 40 CFR 63 Subpart ZZZZ, these controls are cost-effective. All additional costs calculation and cost evaluations are considered in addition to the currently controlled emission levels.

5.4.4.1.1. Selective Catalytic Reduction Cost Effectiveness

To simplify the costs associated with the SCR systems, the engines are treated as identical units, although this is a slight oversimplification the engines do fall within a similar size rating. Also the efficiency of an SCR system drops off the smaller the engine rating due to mixing in the exhaust stream, so although the SCR system may be slightly over priced for the smaller engines the increased urea consumption will make up for the bias.

The pumping stations where the engines are housed consist of platforms built over water canals at over one dozen different remote locations within the overall approximately 75,000 acre the solar pond system. Ammonia presented too many safety concerns to be considered a viable option, the following cost analysis will look only at the use of urea as the chemical reagent.

An SCR system equipped with a 4,000-gallon urea storage tank fitted with a heating system to prevent urea freezing was analyzed. The costs provided in Table 5-10 below are estimates by Caterpillar based on systems they have in place for other engines of a similar size.

Table 5-10: SCR Retrofit Costs for Diesel Engines

CAPITAL COSTS				
Direct Costs			**Installation Costs**	
SCR System	$20,000		Surface Equipment	$5,000
Urea Tank	$3,500		Startup	$250
Urea Tank Heating System	$4,500		Contractor Fee	$1,500
Taxes	$2,030		Contingency	$800
			Testing	$250
Total	$30,030		**Total**	$7,800
ANNUAL COSTS			**Totals**	
Direct Costs			Interest rate	7.00%
Maintenance (hrs @ $)	52 @ $20		CRF	0.0944
Cost of Maintenance hours	$1,040		Life of Control (yrs)	20
Maintenance Parts	$2,500		Total Capital Costs	$37,830
Urea Cost ($1.00/gal @ 5 gal/hr @ 4,000 hr/yr)	$20,000		Annualized Capital	$3,571
Catalyst Module (20,000 hr life, $20,000 cost to replace)	$5,000		Annual Maintenance Cost	$28,540
Total	$28,540.00		Total Annual Cost	**$32,111**

Continuing with the simplified model if each of the 30 engines play an equal role in 71.65 tons of NO_X emitted annually from the diesel engines on site, then each engine would emit 2.39 tons. A summary of the cost breakdown per engine and as an entire facility can be found in Table 5-11.

Table 5-11: Summary of SCR Cost Analysis

	Total Annual Cost ($/yr)	Control Efficiency	NO_X Emissions Reduction	Cost Effectiveness ($/ton removed)
Per Engine Basis	$32,111	95%	2.27	$14,146
All Engines	$963,326	95%	68.10	

The costs associated with the SCR exceed that which would be considered economically feasible. As a result, the use of SCR systems for NO_X control has been ruled out as a viable retrofit option for NO_X control.

5.4.4.1.2. Exhaust Gas Recirculation Cost Effectiveness

The estimated cost for a low-pressure exhaust gas recirculation system including a diesel particulate filter is somewhere in the range of $18,000 to $20,000[15]. A detailed cost breakdown

[15] *Diesel Retrofit*. (2020, July 22). Retrieved from Manufacturers of Emission Controls Association: http://www.meca.org/galleries/files/DieselRetrofitFAQ_0106.pdf

was not performed for an EGR system, the simple cost of the unit alone coupled with the increased ware on the engines regardless of maintenance makes these units not economical. A Summary of the EGR Cost Analysis can be found in Table 5-12.

Table 5-12: Summary of EGR Cost Analysis

	Total Annual Cost ($/yr)	Control Efficiency	NO_X Emissions Reduction	Cost Effectiveness ($/ton removed)
Per Engine Basis	$20,000.00	40%	0.96	$20,833.33
All Engines	$600,00.00	40%	28.80	

The emissions reductions from this unit cannot make up the costs to purchase the units, not even considering the costs to install or maintain the engines once installed. The EGR units have been ruled out as a viable option for NO_X control.

5.4.4.2. Timing for Compliance

USM believes that reasonable progress compliant controls are already in place, and any additional controls are unnecessary. However, if UDAQ determines that one of the control methods analyzed in this report is required to achieve reasonable progress, it is anticipated that this change would be implemented during the period of the second long-term strategy for regional haze (approximately ten years following the reasonable progress determination for this second planning period).

5.4.4.3. Energy and Other Impact Not Related to Air Quality

The biggest concern related to NO_X control that lies outside of air quality impacts would be that of ammonia storage. Ammonia is a caustic substance that is harmful to organic life, storing large quantities of it has the potential safety issues for personnel and for spills that can cause adverse environmental and health impacts.

The associated ammonia slip can also increase condensable $PM_{2.5}$ which contributes directly to visibility impairments.

5.4.4.4. Remaining Useful Life of the Source

The engines remaining life varies, but with proper maintenance and overhaul the engines are expected to last at least an additional 20 years, a similar lifetime to that of the control equipment being considered in this analysis.

5.4.4.5. Summary and Conclusions

USM has determined that the available retrofit control technologies are too costly for consideration of use at their facility. The diesel engines will continue to emit roughly 71.65 tons of NO_X annually. USM will continue to operate the diesel engines as they are currently configured.

5.5. HYDROCHLORIC ACID PLANT

5.5.1. Step 1: Identify All Potentially Available Retrofit NO_X Control Technologies

USM produces a pure food grade hydrochloric acid (HCl) at their acid plant. The concentration of HCl is roughly ~36% and is generated in a similar fashion to how the chlorine reduction burner works, by combusting natural gas in the presence of purified chlorine gas. The chemical reaction below demonstrates HCl formation using the combustion process.

$$CH4 + O2 + 2Cl2 \rightarrow CO2 + 4HCl$$

The average annual usage for the HCl plant is assumed to be 4,380 hours annually, exactly half of the calendar year. The HCl plant operates only when USM has suppliers in need of food grade HCl. To date in 2020, the HCl plant has not been utilized onsite, but is anticipated to resume production in the fall of 2020.

NO_X emissions associated with the HCl plant is generated through natural gas combustion in the burner. The unit is rated for less than 10 MMBtu/hr and generated 4.32 tons in 2018.

Potentially available retrofit controls for the combustion unit are the same controls typically available to other natural gas combustion units. Common retrofit controls are listed in Table 5-13 below.

Table 5-13: Available Retrofit NO_X Control Technologies for HCl Plant

NO_X Control Technologies	
Combustion Controls	Water or Steam Injection
	Dry Low-NO_X
Post-Combustion Controls	Selective Catalytic Reduction (SCR)

5.5.1.1. Combustion Controls

5.5.1.1.1. Water or Steam Injection

Steam or water injection controls the formation of NO_X emissions by decreasing the peak flame temperature. It is an effective tool for reducing the formation of thermal NO_X in all but regenerative cycle combustors.

NO_X emission reductions of generally 60-70% can be achieved using water or steam injection at water-to-fuel ratios of 0.2:1 to 1:1. It is important to utilize water or steam free of contaminants, so a water treatment system is an integral component of a wet control system.

Several mechanical limits exist when it comes to water or steam injection systems, things like combustion operating instabilities, increased CO, heat rate penalties, combustion flame blow-off or flame-out. These limitations can decrease the efficiency of the water or steam injection system and increase the maintenance required.

5.5.1.1.2. Dry Low-NO_X

NO_X emission control techniques that are performed in without the injection of water or steam are referred to as dry controls, but the method for emissions reductions is the same, reducing the peak flame temperature. This is generally accomplished by lean combustion or staged combustion.

Lean combustion refers to a technique that reduces the air/fuel ratio beyond that of normal stoichiometric operation (equivalence ratio = 1) to an air/fuel equivalence ratio of 2, i.e. very lean. This reduces the combustion temperature by reducing the air required for combustion below stoichiometric levels. This method is only achievable under normal load range, during periods of startup or low load a transition program with higher air/fuel ratios is required. This results in increased NO_X emissions during periods of startup or low load situations.

Staged combustion is another technique to lower NO_X emissions, this strategy utilizes multiple combustion zones, usually two. The first zone operates lean or rich, but the second zone always operates lean. The incomplete combustion that results in the first combustions zone is further combusted in the lean second combustion zone resulting in reduced NO_X formation.

5.5.1.2. Post-Combustion Controls

5.1.1.2.1. Selective Catalytic Reduction (SCR)

In the SCR process, ammonia or urea is injected in the exhaust gas stream reacting with NO_X in the presence of a catalyst to form molecular nitrogen and water. A SCR system can achieve a 95% reduction of NO_X emissions.

The catalytic NO_X-ammonia reaction takes place over a limited temperature range, 600-750 °F, anything about ~850 °F and the catalyst is damaged irreversibly. Ammonia slip is also a concern when utilizing an SCR for NO_X emission reductions, as well as ammonia or urea storage, and costs of disposal of spent catalysts can also be a concern.

5.5.2. Step 2: Eliminate Technically Infeasible Options

The combustion unit at the HCl plant is the primary generator of the HCl product, as a result the plants operation must be taken into consideration when talking about NO_X controls for the combustion unit.

5.5.2.1. Combustion Controls

Both water or steam injection and dry low-NO_X combustion controls are technically infeasible for the HCl plant. Both controls reduce the formation of thermal NO_X by reducing peak flame temperatures, this reduction in peak flame temperature would alter the performance of the HCl plant and as a result neither option will not be evaluated further.

5.5.2.2. Post-Combustion Controls

5.5.2.2.1. Selective Catalytic Reduction (SCR)

Although an SCR system is a feasible option retrofitting the HCl plant sizing, installation space, and operating the unit would be so challenging it is not technically feasible. The RBLC lists a facility in Louisiana that has installed an SCR unit onto a HCl plant[16], but provided no cost verification, and listed the emission type as LAER, which exceeds the requirements of this BART analysis many times over.

Sizing the SCR unit is challenging because the burner rate is not static, and the run times can be quite short. USM only operates the HCl plant when they have a supplier in need of the product. Depending on the economy and availability this can be quite infrequent. The minimal operating schedule would also make operating the unit a challenge. Historically there have been operation times that vary from half a day to several weeks. Downtime of the plant can be up to 8 months or more, requiring additional maintenance to get the unit operational upon startup.

The installation space required for an SCR unit is not extremely large, however, the exhaust stack on the HCl plant sits inside the racking and piping for the plant itself, and although it is probably feasible it would be a challenging retrofit.

For the reasons listed above this control technology is not considered technically feasible as a retrofit option for the hydrochloric acid plant and was not evaluated further.

5.5.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 of the review process is to rank the technically feasible options by how effective they are at removing NO_X emissions. As no control technologies are technically feasible for this specific operations at USM, no ranking is possible.

5.5.4. Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

As no remaining retrofit control technologies are technically feasible analysis of the above list is not possible.

5.1.4.1. Summary and Conclusions

The HCl plant at USM operates infrequently and has a minimal impact on the overall NO_X emissions associated with the plant. In 2018, the HCl plant was responsible for 4.32 tons of NO_X. No retrofit control options were technically feasible for the operations at USM. USM will continue to operate the HCl plant as it currently configured on an as needed basis.

[16] See Appendix B for RBLC search Results

5.6. CASTING HOUSE

5.6.1. Step 1: Identify All Potentially Available Retrofit NO_X Control Technologies

The cast house at USM operates eleven natural gas fired crucible furnaces. Each crucible furnace is equipped with six 1 MMBtu/hr burners, three in an upper horizontal angled array and three in a lower horizontal angled array, for a total heating rating of 6 MMBtu/hr per crucible furnace, for a total of 66 burners. After an extensive search of the RBLC database only two entries were found for crucible furnaces, both employing smaller burners in numerous quantities like operations at USM. Both the entries in the RBLC utilized AP-42 emission factors and operated with no emission controls[17]. Given the smaller size of these natural gas burners, and their array and installation it is unlikely that any control technologies exist, it is even less likely that a retrofit control technology would exist. No additional analysis was performed for the burners associated with the crucible furnaces USM operates.

The cast house also utilizes tool heating boxes, they are top and open-faced boxes with four small bayonet style burners, these burners typically range from 0.1 to 0.25 MMBtu/hr. The tool heating boxes sole purpose is safety. The tools used in USM casting house are heated up to remove any potential for water vapor or condensation forming on the metal when it contacts the heated magnesium metal. Water and magnesium can result in the formation of hydrogen gas, which is very explosive. These tool heating boxes are an integral part of the process and perform mandatory safety tasks. Given their low burner rating no retrofit controls exist that would still allow the heating boxes to function as needed. No additional analysis was performed for the tool heating boxes at USM.

5.6.2. Step 2: Eliminate Technically Infeasible Options

No retrofit controls were identified for the 1 MMBtu/hr burners utilized in the casting house at USM. Similarly, no retrofit controls were identified for the tool heating boxes that utilize 0.1 to 0.25 MMBtu/hr burners.

5.6.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 of the review process is to rank the technically feasible options by how effective they are at removing NO_X emissions. As no control technologies are technically feasible for the specific operations at USM, no ranking is possible.

5.6.4. Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance

[17] See Appendix B for RBLC search Results

- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

As no remaining retrofit control technologies are technically feasible analysis of the above list is not possible.

5.6.4.1. Summary and Conclusions

USM operates eleven crucible furnaces for the purposes of maintaining magnesium metal in a molten state and casting that molten magnesium into ingots. Each furnace utilizes six smaller burners rated at 1 MMBtu/hr each. Additionally, there are multiple tool heating racks placed strategically around the casting house that are used to heat tools that will be in contact with heated magnesium ore. The combination of these burner units combusting natural gas emit 14.70 tons of NO_X emission annually. Given that there is a total of ~80 burners in the casting house, each contributing a minimal amount of NO_X emissions. Controls for these small combustion devices are not readily available, and none were found during the BART analysis. USM will continue to operate the casting house as it is currently configured.

5.7. LITHIUM PLANT

USM has recently constructed the lithium plant, which finished the permitting process on April 20, 2020. The lithium plant digests existing waste coupled with current waste streams to extract the available lithium ore. The NO_X emissions from the plant come from natural gas combustion units. The plant consists of two boilers, a 63 and an 84 MMBtu/hr; and two evaporative burners, a 50 and a 100 MMBtu/hr. The analysis for the lithium plant was broken into two sections, a natural gas fired boiler section and an evaporative burner section.

5.7.1. Natural Gas Fired Boilers

The natural gas fired boilers were installed in early 2020 and went through a BACT analysis earlier this year. They are ultra-low-NO_X units capable of meeting a concentration limit of 9 ppm NO_X or less[18]. As BACT is more inclusive than BART performing a BART analysis on these boilers would be redundant and would yield no results. No additional analysis was performed on the 62 MMBtu/hr or 84 MMBtu/hr natural gas fired boilers installed in 2020, however the NO_X BACT analysis that was completed for USM's AO is included below.

5.7.1.1. Boiler BACT Analysis from AO dated April 20, 2020

Two boilers are proposed for the Lithium Carbonate Production Plant: a 63 MMBtu/hr unit and an 84 MMBtu/hr unit. Both boilers will be fueled by natural gas and will operate 8,760 hours per year. NO_X emissions from both boilers combined will be 6.04 tons annually.

NO_X

NO_X emissions are generated from the natural gas combustion process.

[18] Per UDAQ Approval Order DAQE-AN107160050-20 dated April 20, 2020.

Available Control Technologies

Technically feasible options for NO_X control include selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), low NO_X burners, ultra-low NO_X burners, flue gas recirculation (FGR), and good combustion practices.

SCR is an add-on technology that chemically reduces NO_X compounds from the stack flue gas to N_2 and water. Ammonia is injected into the flue gas upstream of the catalyst chamber. The ammonia-air mixture then passes through a thermal catalytic reactor where the catalytic reaction is completed. NO_X reduction in SCR is only effective at high temperatures (480 F to 800 F), so additional heating of the emission stream may be required to meet optimal operating temperatures. SCR NO_X removal efficiencies are between 70% and 90%.

SNCR is similar to SCR in the use of ammonia as a reductant to reduce NO_X compounds to molecular N_2 and water but the technology does not utilize a catalyst. The ammonia is injected directly into the primary combustion zone where temperatures reach 1,400 to 2,000 F. NO_X reduction in SNCR is only effective at high temperatures (1600 F to 2100 F), so additional heating of the emission stream may be required to meet optimal operating temperatures. SNCR NO_X removal efficiencies vary between 30% and 50%.

Low and ultra-low NO_X burners are commonly used to reduce NO_X emissions from natural gas combustion equipment. Low NO_X burners can achieve NO_X emissions rates of 30 ppmvd and ultra-low NO_X burners will achieve NO_X emission rates of 9 ppmvd.

FGR consists of recirculating a portion of the flue gas to the combustion zone in order to lower the peak flame temperature and results in reduced thermal NO_X production. FGR is one of the main reduction methods for low-NO_X or ultra-low NO_X burners.

Good combustion practices and use of clean fuel includes the use of gaseous fuels and combustion practices to minimize the formation of NO_X emissions from the combustion process.

Technical and Economic Feasibility

All control technologies identified are technically feasible. USM has proposed to install boilers with ultra-low NO_X burners rated at 9 ppmvd.

The proposed boilers with ultra-low NO_X burners will generate relatively low NO_X emissions (6.04 tpy for both boilers). The addition of SCR and SNCR would reduce these emissions by 50 to 80% from an ultra-low NO_X burner, or 3 to 5 ton reduction. Due to the high costs of SCR and SNCR systems, this reduction would not be considered cost effective. Furthermore, there are several considerations with SCR and SNCRs that make these controls not technically feasible for boilers like the units proposed for the Lithium Carbonate Plant.

1) Due to the costs of SCR and SNCR systems, these technologies are usually applied to large combustion units (>100 MMBtu/hr).
2) High operating temperature requirements may require additional heating of the exhaust stream.
3) Health and safety considerations since SCR and SNCR require storage and handling of ammonia, a hazardous chemical.

4) Ammonia slip (i.e. ammonia emissions from unreacted ammonia) pose additional environmental and safety concerns

Given these technical difficulties, environmental concerns, and the relatively low NO_X emissions from the boilers with ultra-low NO_X burners, SCR and SNCR are not considered a feasible option.

Select BACT

DAQ considers BACT for NO_X from the boilers as the use of an ultra-low NO_X burners rated at 9 ppm, good combustion practices, and limiting visible emissions to 10% opacity from each boiler.

5.7.2. Evaporative Burners

The natural gas fired evaporative burners were similarly installed in early 2020 and went through a BACT analysis earlier this year. They are low-NO_X units capable of meeting a concentration limit of 30 ppm NO_X or less[19]. As BACT is more inclusive than BART performing a BART analysis on these evaporative burners would be redundant and would yield no results. No additional analysis was performed on the 50 MMBtu/hr or 100 MMBtu/hr evaporative burners installed in 2020, however the NO_X BACT analysis that was completed for USM's AO is included below.

5.7.2.1. Evaporative Burner BACT Analysis from AO dated April 20, 2020

USM has proposed to install two evaporator burners to supply hot exhaust gases for evaporating water from process liquors. One evaporator burner will have a heat input rating of 100 MMBtu/hr and the other evaporator burner will have a heat input rating of 50 MMBtu/hr. Both evaporator burners will be fueled by natural gas and will operate 8,760 hours per year. NO_X emissions from both evaporator burners combined are 20.57 tons annually.

NO_X

NO_X emissions will be generated from the natural gas combustion process.

Available Control Technologies

Technically feasible options for NO_X control include SCR, SNCR, low NO_X burners, ultra-low NO_X burners, FGR, and good combustion practices. These technologies were described above in the Boilers NO_X section.

Technical and Economic Feasibility

All control technologies identified are technically feasible. USM considered three burner options: uncontrolled at 130 ppmvd NO_X, low NO_X at 30 ppmvd, and ultra-low NO_X at 9-15 ppmvd.

According to the manufacturer of the burners, ultra-low NO_X burners are not technically feasible for the operating requirements of the Lithium Carbonate Plant.

[19] Per UDAQ Approval Order DAQE-AN107160050-20 dated April 20, 2020.

The first operating requirement is the process temperature. The process requires a temperature of 1,500 degrees F. According to burner manufacturer, ultra-low NO_X burners are limited to a maximum temperature of 1,000 degrees F at the site elevation (4,220 feet above sea level).

The second operating requirement is the turndown ratio. Ultra-low NO_X burners are limited to a turndown ratio of 5:1, while a low NO_X burner is capable of 13:1 turndown ratio. Turndown is a ratio of capacity at full fire to its lowest firing point before shut-down and indicates the number of on/off cycles. At each cycle, air is purged through the unit to remove any explosive gases. The lower the turndown ratio, the more sensitive the burner is to low firing points, and more purge cycles are required. Purge cycles removes heat from the burner and increases the number of startups. A low turndown ratio increases the number of on/off cycles, which can in turn deteriorate burner components and increase maintenance costs. The higher turndown ratio makes the burner more responsive to variable loads and is more suitable for the anticipated fluctuations in daily operations. The low NO_X burner with a higher turndown ratio is more suitable for the operations at the Lithium Carbonate Plant.

The third operating requirement is system reliability. The proposed burner will be fired in a combustion chamber which is attached to a spray tower. The spray tower will deliver the brine to be heated by the burner. Brine will be delivered at variable flows and distribution which will affect the back pressure on the burner. An ultra-low NO_X burner would be more sensitive to fluctuations in back pressure in the spray towers and would not be suitable for the planned process of the Lithium Carbonate Plant.

Given these operational considerations, an ultra-low NO_X burner is not considered technically feasible for operations at the Lithium Carbonate Plant.

USM conducted a cost analysis to determine the economic feasibility of the low NO_X burners (30 ppm). For the 100 MMBtu/hr burner, the capital cost of a low NO_X burner was estimated at \$163,451 and would reduce NO_X emissions by 24.91 tpy. This would result in a cost efficiency of \$6,536 per ton of NO_x removed. For the 50 MMBtu/hr burner, the capital cost of a low NO_X burner was estimated at \$122,499 and would reduce NO_X emissions by 13.64 tpy. This would result in a cost efficiency of \$8,373 per ton of NO_X removed. Therefore, low NO_X burners were determined to be economically feasible for both burners.

SCR and SNCR are not technically or economically feasible options for the same reasons previously discussed in the Boiler section.

Select BACT

BACT for these burners is a 10% opacity limitation and installation of low-NO_X burners, that will be certified by the manufacture to meet 30 ppm NO_X emissions.

6. CONCLUSION

This report outlines USM's evaluation of possible retrofit options for all NO_X emitting units onsite at their Rowley Plant located in Tooele County, Utah, in an attempt at reducing their NO_X emissions facility wide and reducing their impact on visibility impairment issues. The results of this report found that it is potentially technologically and economically feasible to install a flue gas recirculation unit on the Riley boiler, reducing their NO_X emissions by an estimated 22.6 tons annually. Aside from this change, there were currently no other technically or economically feasible options available for USM's Rowley Plant.

Pending further technological and cost refinement, the implementation schedule for the installation of the FGR unit may be installed prior to the end of 2028. Therefore, the emissions for the 2028 modeling scenario could be an estimated 22.6 tons less than the 2018 baseline year NO_X emissions.

APPENDIX A: RILEY BOILER SCR COST ESTIMATE

Cost Estimate		
USM Riley Boiler SCR Cost Analysis using EPA's SCR Cost Manual		

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 80{,}000 \times (200/B_{MW})^{0.35} \times BMW \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$3,262,190	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$86,684	in 2018 dollars
Indirect Annual Costs (IDAC) =	$282,646	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$369,330	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$16,311	in 2018 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$48,399	in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$17,910	in 2018 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$4,064	in 2018 dollars
Direct Annual Cost =		$86,684	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,716	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$279,930	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$282,646	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$369,330	per year in 2018 dollars
NOx Removed =	38	tons/year
Cost Effectiveness =	$9,726	per ton of NOx removed in 2018 dollars

APPENDIX B: RBLC SEARCH RESULTS

Table B-1: RBLC Search Results

USM EQUIPMENT	RBLC ID	FACILITY NAME	COMPANY NAME	OPERATING STATE	PERMIT ISSUE DATE	PROCESS NAME	FUEL SOURCE	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	BASIS
Casting House	MI-0301	Alchem Aluminum	Alchem Aluminum, Inc.	Michigan	5/2/2000	Crucible Heaters/Stations	Natural Gas	2.00 MMBtu/hr	NO_X	None, AP-42	0.14 lb/MMBtu	
HCl Plant	LA-0242	Hydrochloric Acid Production Furnace	Shintech Louisiana, LLC	Louisiana	6/29/2010	Hydrochloric Acid Production Furnace	Natural Gas	39.00 MMBtu/hr	NO_X	SCR	0.0146 lb/MMBtu	
Riley Boiler	PA-0319	Renaissance Energy Center	APV Renaissance Partners	Pennsylvania	8/27/2018	Auxiliary Boiler	Natural Gas	88.00 MMBtu/hr	NO_X	Low NOX Burners, FGR	0.02 lb/MMBtu	LAER
Riley Boiler	WV-0032	Brooke County Power Plant	ESC Brooke County Power I, LLC	West Virginia	9/18/2018	Auxiliary Boiler	Natural Gas	111.6 MMBtu/hr	NO_X	Low NoX burner	0.011 lb/MMBtu	BACT - PSD
Riley Boiler	MI-0433	MEC North, LLC & MEC South, LLC	Marchall Energy Center LLC	Michigan	6/29/2018	Auxiliary Boiler	Natural Gas	61.5 MMBtu/hr	NO_X	Low NOX burners, FGR	0.04 lb/MMBtu	BACT - PSD
Riley Boiler	FL-0367	Shady Hills Combined Cycle Facility	Shady Hilly Energy Center, LLC	Florida	7/27/2018	Auxiliary Boiler	Natural Gas	60.00 MMBtu/hr	NO_X	Low NOX burner	0.05 lb/MMBtu	BACT - PSD
Riley Boiler	WY-0011	CIG	CIG	Wyoming	8/25/1976	Boiler, Gas, 2	Natural Gas	48.40 MMBtu/hr	NO_X	Design	0.2 lb/MMBtu	Other
Riley Boiler	TX-0079.A	Shintech, Inc.	Shintech, Inc.	Texas	1/5/1981	Boiler, Steam	Natural Gas	55.00 MMBtu/hr	NO_X	Low Nox Burners	0.12 lb/MMBtu	BACT - PSD
Riley Boiler	IL-0020	Archer Daniels Midland	Archer Daniels Midland	Illinois	5/28/1982	Boiler	Natural Gas	90.00 MMBtu/hr	NO_X	Design	0.17 lb/MMBtu	BACT - PSD