



REGIONAL HAZE FOUR-FACTOR ANALYSIS

DCP Operating Company, LP
Linam Ranch Gas Plant



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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 DCP Operating Company, LP (DCP), that its Linam Ranch Gas Plant (Linam) was identified as one of the sources possibly contributing to regional haze at nearby Class I areas.

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 DCP 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 (SO₂) shall be included in this analysis. The equipment at the facility

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 to a Four-Factor Analysis

Equipment	NO_x Hourly PTE (lb/hr)	NO_x Annual PTE (tpy)	NO_x Subject to Analysis? (Yes/No)	SO₂ Hourly PTE (lb/hr)	SO₂ Annual PTE (tpy)	SO₂ Subject to Analysis? (Yes/No)
Clark TLA-6 2SLB RICE (Unit 6)	39.29		Yes	0.010		No
Clark TLA-6 2SLB RICE (Unit 7)	39.29		Yes	0.010		No
Clark HBA-6 2SLB RICE (Unit 8)	47.49	566.08	Yes	0.0070	0.12	No
Clark HBA-6 2SLB RICE (Unit 9)	47.49		Yes	0.0070		No
Clark HBA-6 2SLB RICE (Unit 10)	47.49		Yes	0.0070		No
Clark HBA-6 2SLB RICE (Unit 11)	47.49		Yes	0.0070		No
Solar Centaur T-70 Turbine (Unit 29)	11.82	51.78	Yes	0.26	1.16	No
Solar Centaur T-70 Turbine (Unit 30)	11.26	49.32	Yes	0.25	1.10	No
Solar Centaur T-4700 Turbine (Unit 31)	26.03	114.01	Yes	0.13	0.55	No
Solar Centaur T-4000 Turbine (Unit 32B)	23.72	103.88	Yes	0.12	0.54	No
ESD Flare (Unit 4A)	14.80	0.88	No*	9301.45	4.13	No*

* Pursuant to NMED Guidance received on 9/23/2019, the Four Factor Analysis is to be completed for steady state sources of emissions only; as such, emissions from SSM/M activities are not subject to a Four Factor Analysis.

Once the applicability of the four factor analysis has been determined for process equipment and pollutants, potential retrofit control technologies must be identified. In accordance with 40 CFR 51 Appendix Y and at the recommendation of the NMED¹, potentially applicable emissions reduction technologies are informed by reviewing the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC). In order to determine the most relevant and current retrofit controls available, the RBLC was 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

At Linam, the six (6) natural gas-fired two-stroke lean burn engines (Units 6, 7, 8, 9, 10 & 11) and four (4) combustion turbines (Units 29, 30, 31 & 32B) are subject to this four-factor analysis based on NO_x emissions. No units are subject based on SO₂ emissions. The turbines are either Solar Centaur T-70, T-4000 or T-4700 units. Manufacture dates for these units range from 1979 to 1995. The engines are either Clark TLA-6 or HBA-6 units. Manufacture dates range from 1951 to 1974 for the engines.

2.1. NATURAL GAS-FIRED COMBUSTION TURBINES

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 dictate 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 Linam are regenerative cycle turbines, which are essentially simple cycle gas turbine with an added heat exchanger.

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 (N₂) and oxygen (O₂) 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 Linam'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.

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

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

³ Ibid.

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 Options for Combustion Turbines

Control Equipment	Technically Feasible?	NO_x Control Efficiency
Good Combustion Practices	Yes	Base Case
Improved Combustion Technology	Yes	vendor ppm guarantee
Water/Steam Injection	No	N/A
Selective Catalytic Reduction	Yes	70%

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 Linam. However, these good combustion practices are currently in use at Linam, as required by various conditions in its Title V and NSR permits. Accordingly, no further assessment of these control practices has been included in this report.

2.1.2.2. Improved Combustion Technology

The improved combustion technology control option, commonly referred to as 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 chamber. There are several levels of improvements that can be made to the combustion chamber, which achieve this NO_x control at varying levels. Based on communications with Solar, the DLN control option involves a thorough overhaul of the combustion section of the turbine, including replacement of the air and fuel injection nozzles, modifications to or complete replacement of the combustion chamber, and replacement of the electrical control system for the unit. Solar’s specific technology, SoLoNO_x utilizes lean-premixed combustion technology to ensure an extremely uniform air/fuel mixture and stringently controls the combustion process to prevent undesirable emissions from forming. An overall reduction efficiency of 55% - 80% can be achieved for the turbines located at this facility

⁴ Ibid.

using this technology in comparison to permitted PTE. Reduction efficiencies are dependent on, and can vary based on, existing technologies already installed on the facility's units.

Solar has performed numerous retrofits of existing turbines with SoLoNO_x and, even though there are extensive overhaul and implementation costs, the technology is technically feasible. Therefore, a cost analysis will be completed to determine the cost effectiveness per ton of NO_x removed.

2.1.2.3. Water/Steam Injection

Water or steam injection is a control technology for gas turbines that has been demonstrated to effectively suppress NO_x emissions. Injection of steam and water has the effect of increasing the thermal mass by dilution and thereby reducing the peak temperature in the flame zone. There is an additional benefit of absorbing the latent heat of vaporization from the flame zone when water injection is utilized. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.⁵

Steam injection is not discussed as an option for these Solar turbines at Linam because Solar does not manufacture turbines with steam injection technology. Although the Solar turbines are mechanically capable of supporting water injection, Solar has stated that they do not offer water injection retrofits for any of the Centaur 40 conventional combustion line of turbines. This is primarily due to the design of the combustor housing of the conventional Centaur 40. The injectors on this style of combustor intersect directly into the combustor without using direct air flow for the direction of fuel. The style of injector needed to implement water injection technology is referred to by Solar as a Dual Lined Injector. This type of injector introduces fuel laterally into the front of a combustor and utilizes a controlled flow to disperse fuel.

Solar considers the control technique to be antiquated technology in comparison to the other control methods they have available, such as SoLoNO_x. Solar has retired this control option and does not recommend water injection be installed to control emissions from their turbine units. Also, Solar stated that if direct modifications are made to the turbine engine or it's supporting hardware to retrofit third party water injection control, then Solar will not uphold any existing warranty to the unit and previous maintenance work done by Solar to the turbines. Combustion turbine units are high capital value assets and this retrofit would create a high risk factor going against manufacturer's recommendation.

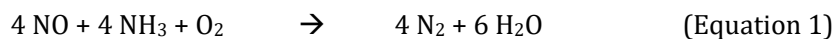
Furthermore, per conversations with Solar, approximately 5 gallons per minute (gpm) of de-ionized or de-mineralized water will be needed to properly implement this control. For a continuously operating turbine, this represents a total water usage of approximately 2.6 million gallons per year, per unit, without taking into consideration leaks and evaporative losses that would occur during transport. Securing the availability of such a large quantity of water will be a difficult even without factoring in the necessary de-ionization and de-mineralization treatment.

Although the Solar turbines on site have the potential to be mechanically retrofitted with water injection, the facility also does not have access to sufficient water for this technology. Additionally, based on the high mineral content of water in the Permian Basin, even when filtration techniques are implemented, DCP engineers have determined that continuous water injection poses a high risk for vibrational imbalance on rotating equipment, which may cause critical damage to the equipment and ultimately decrease the equipment life expectancy. For these reasons, DCP has deemed this control technology as technically infeasible for the turbines located at Linam.

⁵ U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"

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 (N₂) and water (H₂O).⁶ The chemical reactions for this process are shown in the equations below.



A 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 sites 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

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.

Assuming that any space limitations can be overcome, SCR is considered a technically feasible control option for the turbines located at Linam. SCR units typically achieve 65% to 90% NO_x reduction, dependent on the exhaust temperature and upstream NO_x concentration. If the NO_x concentration is already low, it can be difficult to achieve these control efficiencies.¹⁰ A cost analysis is completed for SCR using an overall reduction efficiency of 70%.

2.2. NATURAL GAS-FIRED TWO-STROKE LEAN-BURN (2SLB) ENGINES

2.2.1. Two-Stroke Lean-Burn Engines Background

A reciprocating internal combustion engine (RICE) is a device that uses the combustion of fuel and air in an internal chamber to generate a reciprocating motion and convert heat energy into mechanical work. The units use a piston to draw air and fuel into the combustion chamber and compress it. The compressed air/fuel mixture is then ignited, generating combustion in the chamber. The energy of combustion pushes out the piston, turning

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.

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

¹⁰ Ibid.

a crankshaft and producing mechanical work. In the same cycle, the products of combustion remaining in the chamber are released and exhausted from the unit.

Natural gas-fired RICE are separated into multiple design classes, including 2-stroke lean-burn (2SLB), 4-stroke lean-burn (4SLB), and 4-stroke rich-burn (4SRB). The four-stroke design uses four strokes of the piston, or two turns of the crankshaft, to complete the power cycle. The two-stroke design completes the power cycle in a single revolution of the crankshaft. Rich-burn engines are designed to operate close to the stoichiometric, or chemically balanced, air-to-fuel ratio (around 16:1) with exhaust oxygen levels less than 4%, while lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1), with exhaust oxygen levels of 12% or more.¹¹

NO_x is formed in reciprocating engines via the same three mechanisms applicable to the turbines:

- (1) Thermal NO_x - the thermal dissociation and subsequent reaction of nitrogen (N₂) and oxygen (O₂) molecules during combustion,
- (2) Fuel NO_x - the evolution and reaction of fuel-bound nitrogen compounds with oxygen, and
- (3) Prompt NO_x - the early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The Linam engines also use natural gas fuel; therefore, the formation of prompt and fuel NO_x will again be insignificant, and this analysis will focus on thermal NO_x. The rate of NO_x formation through the thermal NO_x mechanism is highly dependent upon the air-to-fuel ratio, combustion temperature, and residence time at the combustion temperature. Maximum thermal NO_x formation occurs near the stoichiometric air-to-fuel mixture ratio because combustion temperatures are greatest at this ratio.¹²

NO_x reduction in natural gas-fired RICE can be accomplished by three general methods, as follows:¹³

- (1) Operational control methods, such as adjusting the timing or other operating parameters.
- (2) Combustion control techniques, for example reducing the peak flame temperature or introducing inerts that limit initial NO_x formation.
- (3) Post-combustion NO_x control technologies, which employ various strategies to chemically reduce NO_x.

The PTE associated with each engine is reported in the facility's New Source Review and Title V permits, as well as summarized in Table 1 of this report.

2.2.2. Potential NO_x Controls for 2SLB Engines

Potential retrofit control options identified for 2SLB RICE were identified via comprehensive review of the RBLC and available technical literature and are summarized in Table 3. A detailed description and discussion of the technical feasibility and anticipated performance of each control is provided below.

¹¹ U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"

¹² Ibid.

¹³ Ibid.

Table 3. Potential Control Equipment for 2SLB RICE

Control Equipment	Technically Feasible?	NO_x Control Efficiency
Good Combustion Practices and Fuel Selection	Yes	Base Case
Clean Burn Technology	No	5% - 30%
Selective Catalytic Reduction	No	N/A
Non-Selective Catalytic Reduction	No	N/A

2.2.2.1. Good Combustion Practices and Fuel Selection

By following the same concepts from engineering knowledge, experience, and manufacturer's recommendations referenced above, good combustion practices for operation of engines can be developed and maintained. This is achieved 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 for the 2SLB engines are similar to those 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 2SLB engines at Linam and these practices are currently in use at Linam, as required by various conditions in its Title V and NSR permit authorizations. Accordingly, no further assessment of these control practices is included in this report.

2.2.2.2. Clean Burn Technology

Clean Burn Technology (CBT) is another term for utilizing combustion mixtures in engines with fuel-lean air-to-fuel ratios. This method of reducing NO_x emissions involves reconfiguring the engines by adding or enhancing an air-to-fuel ratio controller, making the unit capable of operating at more desirable ratios.

Rich-burn engines are normally designed to operate close to the stoichiometric, or chemically balanced, air-to-fuel ratio of 16:1, while lean-burn engines operate at significantly higher air-to-fuel ratios (ranging from 20:1 to 50:1). A combustion mixture with a higher air-to-fuel ratio results in reduced NO_x emissions, because using fuel-lean mixtures lowers the combustion temperature by diluting energy input. As noted, 2SLB engines are typically designed to operate at the high air-to-fuel ratios employed in CBT, so by design these units are in general not amenable to an increase in air-to-fuel ratio to receive significant NO_x reduction benefits. The technology will also have a negative trade-off through an increase in Carbon Monoxide(CO) emissions; however, further increasing the air-to-fuel ratio in lean-burn engines can decrease the NO_x emissions to some degree.¹⁴

Additionally, in order to avoid derating the engine, combustion air must be increased at constant fuel flow. To achieve this, the engine will need to be retrofitted with a turbocharger, which forces additional air into the combustion chamber, as well as an automatic air-to-fuel ratio controller.

Many 2SLB engines, such as naturally aspirated engines, do not have identical air-to-fuel ratios in each cylinder, which can result in limited ability to vary the air-to-fuel ratio. To maintain acceptable engine performance at

¹⁴ State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines, State of New Jersey Department of Environmental Protection, 2003.

lean conditions, high energy ignition systems (HEIS) have been developed that promote flame stability at very lean conditions.¹⁵

2SLB engines are mechanically capable of being retrofit with more sensitive air-to-fuel ratio controllers and running on higher air-to-fuel ratio combustion to control NO_x emissions. However, based on the advanced age, type of engine, and discussion with vendor, DCP has determined that clean burn technology retrofits are physically possible yet deemed technically infeasible for the engines at Linam. The aforementioned available clean burn control technologies are incapable of being retrofit on the existing 70-year-old engines on site.

2.2.2.3. Selective Catalytic Reduction

Implementation of SCR controls for 2SLB engines follows the same process and has the same technical drawbacks as discussed in Section 2.1.2.4 of this report.

Typical concerns for SCR system in regards to ammonia slip or insufficient ammonia was not applicable to the engines at Linam. For engines that typically operate at variable loads, such as engines on gas transmission pipelines, a SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia to gain the reductions needed.¹⁶ As Linam Ranch does not typically operate with variable loads, the facility does not expect to have periods of ammonia slip or insufficient ammonia.

The characteristics of 2SLB engine exhaust streams are well understood across industry to be non-favorable conditions for the chemical reactions necessary for SCR to reduce NO_x emissions effectively. This is due to undesirable processes occurring in SCR systems as lean burn engines, by design, have higher oxygen level in the exhaust system. In the SCR system of a 2SLB engine, several competitive, nonselective reactions will occur with abundant oxygen. These reactions can either produce secondary emissions or, at best, unproductively consume ammonia as complete oxidation of ammonia generates nitric oxide. For the aforementioned reasons, SCR installation on 2SLB engines requires significant understanding of the process to design, implement and maintain as this type of control system often requires retrofit upgrades/modifications to the engine's combustion system resulting in a custom type control system. Due to the aforementioned reasons, SCR systems have not been widely applied to natural gas fired 2SLB engines similar to those at Linam and application of this control technology can only be seen on very large diesel-fired stationary engines and on large combustion turbines.

Additionally, there is historical precedent that installation of SCR on 2SLB engines can result in significant technical complications, including a necessity to derate the engines and unreliable operation post-retrofit due to a back pressure drop that happens with the exhaust system putting constraints on the engines. Many times, sizing of the SCR system has to be custom designed in accordance with the allowable pressure drop in the exhaust per manufacturer specifications. Another issue using a catalyst (part of the SCR system) on a 2SLB engine is poisoning of the catalyst by lubricant because in two stroke engines, the oil is mixed with either the fuel or the air to lubricate the piston.

AP-42 Section 3.2 does list SCR as an available control technology for 2SLB engines, however, the challenges of applying this control technology on 2SLB engines are strongly asserted by RBLC not identifying SCR as a control for these specific engine models.¹⁷

¹⁵ Ibid.

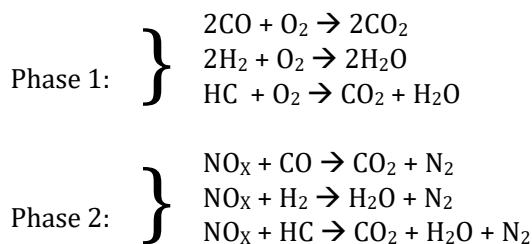
¹⁶ U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"

¹⁷ Ibid.

Due to the technical barriers associated with SCR as applied to specific 2SLB engines, as described above, it has been determined that this method of NO_x control is technically infeasible for the 2SLB engines at Linam.

2.2.2.4. Non-Selective Catalytic Reduction

Non-Selective Catalytic Reduction (NSCR) is a control technique that uses residual hydrocarbons and carbon monoxide (CO) in engine exhaust as a reducing agent for NO_x. In an NSCR system, hydrocarbons and CO are oxidized by oxygen (O₂) and NO_x. The excess hydrocarbons, CO, and NO_x pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H₂O and CO₂, while reducing NO_x to N₂.¹⁸ This technique does not require additional reagents to be injected because the unburnt hydrocarbons in the engine exhaust are used as the reductant. The chemical reactions for this process are shown in the equations below.¹⁹



The reactions in Phase 1 of the chemical process above function to remove excess oxygen from the exhaust stream. This step is necessary because if the oxygen is not removed, it will react more readily with the CO and hydrocarbons than the NO_x, thus reducing the potential for NO_x removal.

Despite this oxygen removal step in the chemical process, the engine exhaust gas stream must already have low levels of excess oxygen, or the oxygen will not be fully removed in Phase 1 and the NO_x removal will not be efficient. Consequently, application of the NSCR control technique is effectively limited to engines with normal exhaust oxygen levels of 4% or less. This does not include lean-burn engines, which typically have an exhaust excess oxygen level around 8%, ranging from 4% to 17%.²⁰

The exhaust oxygen levels for 2SLB engines are not sufficiently low to support the reactions described above; therefore, this technology is not a method used to control NO_x emissions from lean-burn engines. Furthermore, NSCR was not identified in the review of the RBLC as a potential control of NO_x emissions from large natural gas-fired lean-burn stationary RICE and AP-42 Section 3.2 does not list NSCR as an available control technique for 2SLB engines.²¹ For these reasons, it has been determined that this method of NO_x control is infeasible for the 2SLB engines at Linam.

¹⁸ U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines".

¹⁹ U.S. EPA, "Compliance Assurance Monitoring Technical Guidance Document", Appendix B Review Draft, 2005

²⁰ U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"

²¹ Ibid.

3. COST OF COMPLIANCE

DCP 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 using quotes provided by vendors as well as default assumptions from the Cost Control Manual.²² Cost effectiveness considerations for the turbines are discussed below, with costs summarized in Table 4.

3.1. NATURAL GAS-FIRED COMBUSTION TURBINES

Table 4. Cost Analysis Summary of Technically Feasible Control Options for Combustion Turbines at Linam

Control Equipment	Unit	Capital Cost (\$)	Annual Cost (\$)	Emission Reduction (tpy)	Cost Effectiveness (\$/ton) ²³
SoLoNO_x	29	\$188,125	\$605,743	29.21	\$21,278.01
	30	\$188,125	\$618,799	25.97	\$23,829.64
	31	\$1,377,841	\$269,048	86.78	\$3,100.23
	32B	\$1,377,841	\$268,605	21.04	\$12,764.91
SCR	29	\$1,500,000	\$256,678	35.81	\$7,168.48
	30	\$1,500,000	\$254,319	33.08	\$7,688.74
	31	\$1,500,000	\$246,027	78.07	\$3,151.46
	32B	\$1,500,000	\$231,770	19.51	\$11,880.95

²² 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>

²³ Cost Effectiveness and emission reduction as shown in Table 4 are based on 2016 EI information, which reflects a conservative emission calculation approach multiplying turbine operating hours by *permitted PTE emission rate* (lb/hr). Using the actual emission testing data (NSPS KKKK) for these turbines, rather than PTE, the following table reflects what actual emission reduction would be derived from the control technologies and estimated cost effectiveness:

Control Equipment	Unit	Capital Cost (\$)	Annual Cost (\$)	Emission Reduction (tpy)	Cost Effectiveness (\$/ton)
SoLoNO_x	29	\$188,125	\$605,743	0	N/A
	30	\$188,125	\$618,799	0	N/A
	31	\$1,377,841	\$269,048	31.98	\$8,413.01
	32B	\$1,377,841	\$268,605	3.82	\$70,315.54
SCR	29	\$1,500,000	\$256,678	13.08	\$19,623.74
	30	\$1,500,000	\$254,319	5.99	\$42,457.25
	31	\$1,500,000	\$246,027	39.71	\$6,195.60
	32B	\$1,500,000	\$231,770	7.45	\$31,110.07

DCP has selected to use the EPA Air Pollution Control Cost Spreadsheet for SCR to estimate the costs associated with implementing a SCR control system on the turbines at Linam. The estimate incorporates direct capital cost for equipment and vendor labor, direct annual costs (maintenance, operator costs, reagent cost, electricity cost, and catalyst cost), and indirect costs associated with DCP's internal labor, overhead and capital recovery for the project.

This cost estimate assumes that the SCR will reduce NO_x emissions with a 70% efficiency.²⁴ There is no historical data to support a higher control efficiency assumption. In addition, due to the age of the units and current availability of control equipment for them, it is assumed that there would be significant difficulties retrofitting each of these turbines due to initial assessment and the need of a custom engineered SCR system.

These cost estimates have been developed, and applied to the retrofit of these turbines based on two approaches: (i) in Table 4 using the 2016 Emission Inventory submittal for Linam, which is based on PTE for the turbines, so it reflects a potential or theoretical emissions reduction if the turbine were operating at its maximum permitted emissions rate, and; (ii) the Table in Footnote 23 using NSPS KKKK testing data for these turbines reflecting actual emissions for the turbines, thus reflecting actual emissions reductions that would be achieved. A copy of the EPA Air Pollution Control Cost Spreadsheet for each unit is included in Appendix B of this report. Based on actual emissions reductions, these technologies reflect a cost-effectiveness of over \$5,000 per ton on the lowest-side, and generally tens of thousands of dollars per ton for these turbines.

²⁴ U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

4. TIME NECESSARY FOR COMPLIANCE

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 DCP'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. NATURAL GAS-FIRED COMBUSTION TURBINES

DCP estimates that approximately 13 months will be needed to budget, design, procure, and construct the SoLoNO_x control equipment. Factors that have been considered for this anticipated timeline include time for DCP to budget and allocate funds (3 months); 6 months for unit inspection and delivery; and 3 weeks for installation. A contingency factor of 25% has also been applied to account for potential circumstances or setbacks associated with installation of this new technology.

DCP is not certain whether standard SCR technology can be found to be applied to these particular turbines at Linam given their age, design and the fact that such control system is not provided by the turbine manufacturer. It is possible that SCR technology for the turbines at Linam may need to be custom engineered and developed. DCP estimates that approximately 9 months would be needed to budget, design, procure, and construct the SCR control equipment. Factors that have been considered for this anticipated timeline include time for DCP to budget and allocate funds (3 months); and 4 months to design, deliver and install SCR technology. A contingency factor of 25% has also been applied to account for potential circumstances or setbacks associated with installation of this new technology.

5. ENERGY AND NON-AIR ENVIRONMENTAL IMPACTS

This section addresses the potential energy and non-air environmental impacts that installation of the technically feasible control options pose on a source. The consideration of energy impacts involves assessing the impact of a control measure on the energy that is consumed by the source. Non-air environmental impacts are assessed based on the effect of the control on non-air environmental media. Some examples of non-air environmental impacts include water resource depletion, solid waste generation, increased noise and odor pollution, and increased land usage.

5.1. NATURAL GAS-FIRED COMBUSTION TURBINES

The implementation of SCR on the turbines at Linam would result in several energy and non-air impacts. The primary impact of this control would be a significant increase in energy consumption, which would be necessary to power the units. The estimated energy consumption for each unit is summarized in Table 5, and is based on the EPA Air Pollution Control Cost Manual.²⁵ The calculation for these values is included in Appendix B of this report.

Table 5. Energy Consumption Analysis Summary

Unit	Annual Energy Consumption
29	349.7 MWh/year
30	333.1 MWh/year
31	165.8 MWh/year
32B	163.1 MWh/year
Total	1011.6 MWh/year

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/m³. 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.²⁶ 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.²⁷

²⁵ 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>

²⁶ U.S. EPA, EPA/635/R-10/005F, "Toxicological Report of Urea", July 2011

²⁷ U.S. EPA, EPA/635/R-16/163Fc, "Toxicological Review of Ammonia Noncancer Inhalation: Executive Summary", September 2016

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. Linam is a Gas Plant, which already maintains a high level of health and safety risk. DCP considers any increase to this risk unacceptable.

6. REMAINING USEFUL LIFE OF SOURCES

The anticipated remaining useful life of each source is addressed here for the NMED's consideration. The assessment of this factor involves estimating how long the sources analyzed will remain in operation and the lifetime of potential control measures, accounting for equipment and site-specific limitations.

40 CFR Part 51, Appendix Y includes guidance on the characterization of this factor, stating that the remaining useful life of a source will typically be longer than the useful life of the emission control system. Therefore, it is appropriate to annualize compliance costs based on the useful life of the control equipment, rather than the life of the source.²⁸

6.1. NATURAL GAS-FIRED COMBUSTION TURBINES

Based on their current age and operating efficiency, it is estimated that the remaining useful life of the turbines will be longer than the SCR units. The turbines have operated for more than 40 years without any significant deterioration in operating efficiency; therefore, this analysis of the remaining useful life of the equipment will be based on the anticipated useful life of the SoLoNO_x and SCR control technologies.

The estimated useful life of the SoLoNO_x control technology is 20 years, based on default values from the EPA Air Pollution Control Cost Manual.²⁹

The estimated useful life of the SCR control technology is 20 years, based on default values from the EPA Air Pollution Control Cost Manual.³⁰

²⁸ 40 CFR 51, Appendix Y, Section II.B.4.f

²⁹ 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>

³⁰ 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>

7. SUMMARY & CONCLUSIONS

Based on a comprehensive review of the RBLC, available literature, and manufacturer's input of potentially available control technologies for the natural-gas fired turbines located at Linam, DCP has determined that both SoLoNO_x and SCR are technically feasible control options for the turbines. DCP notes that there are significant cost implications for each turbine at the facility with these technologies, that there are significant time and resource expenditures necessary for these technologies, and that there are significant energy and non-air impacts associated with these technologies particularly the SCR technology. DCP further notes that, considering the information reflected in this report, these control technologies are not cost-effective for the estimated reasonable progress improvement, and further notes that DCP's Linam Ranch natural gas processing plant is barely over the agency's Q/d assessment threshold of 5.5 with a Q/d of 7.6.

8. SUPPORTING DOCUMENTATION

Appendix A – RBLC Tables

Appendix B – Cost Calculations and EPA Cost Analysis Spreadsheets

APPENDIX A - RBLC TABLES

RBLC Analysis for Natural Gas Fired Turbines – NO_x Control

IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology	Good Combustion Technique	Improved Combustion Technology (Low-NO _x Combustors, Ultra-Low NO _x Combustors and other improved combustion technology) ^a	Water/Steam Injection ^b	Selective Catalytic Reduction (SCR) ^c
	Control Technology Description	NO _x emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. Primary combustion occurs at lower temperatures under oxygen-deficient conditions. By following EPA's "Good Combustion Practices" guidance document, good combustion practices can be 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 optimal NO _x emissions.	Low-NO _x burners employ multi-staged combustion to inhibit the formation of NO _x . Primary combustion occurs at lower temperatures under oxygen-deficient conditions; secondary combustion occurs in the presence of excess air. This category includes Improved Combustion Technology Lean Head End Liners for the GE turbines assessed here.	Injected water/steam acts as a heat sink, lowering combustion zone peak temperatures, resulting in a decrease in thermal NO _x .	A nitrogen-based reagent (e.g., ammonia, urea) is injected into the exhaust stream downstream of the combustion unit. The reagent reacts selectively with NO _x to produce molecular N ₂ and water in a reactor vessel containing a metallic or ceramic catalyst.
	Other Considerations	N/A	N/A	Results in a small efficiency penalty but an increase in power output. May increase CO and VOC emissions. Not available in certain models.	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 reagent may 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.
	RBLC Database Information	Included in RBLC for control of NO _x emissions from combustion turbines.	Included in RBLC for the control of NO _x emissions from combustion turbines.	Not included in RBLC for the control of NO _x emissions from combustion turbines; identified as a control option based on AP-42 Section 3.1.	Included in RBLC for the control of NO _x emissions from combustion turbines.
ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	Feasibility Discussion	Technically feasible.	Technically infeasible. This option is not available for the turbine model.	Technically infeasible. This option is not available for the turbine model.	Technically feasible.
RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	Base Case			63%

a. California EPA, Air Resources Board, "Section 311 - Non-Selective Catalytic Reduction and Other NO_x Controls," http://www.arb.ca.gov/cap/manuals/cntrldev/sncr_etc/311nsr.htm

b. U.S. EPA, AP-42 Section 3.1, "Stationary Gas Turbines"

c. 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.

Turbine RBLC Results
Completed RBLC Search on 9/19/2019 for a ten year period of 1/1/2019 to 09/19/2015

RBLID	FACILITY NAME	EPA REGION	PERMIT NUM	PROCESS NAME	PROCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	STANDARD EMISSION LIMIT	STANDARD EMISSION UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	COST EFFECTIVENESS	INCREMENTAL COST EFFECTIVENESS	Cost Verified	DOLLAR YEAR USED IN COST ESTIMATES							
LA-0083	ENNA NITROGEN OPERATIONS	8	200804-0786	Pre (3) Natural Gas Fired Combustion Turbines	16.13	Natural Gas	17.8	MMBtu/hr	The (3) Natural Gas fired combustion turbines rated at 17.8 MMBtu/hr each, installed in 2006.	Nitrogen Oxides (NOx)	A	selective Catalytic Reduction	0	lb	0	0	0	0	0							
CA-1333	QUALCOMM INC.	9	2012-009-000-000	Combustion gas turbine	16.13	Natural Gas	4.37	MMBtu/hr	Manufacturing Solar Turbines, Mojave, Monrovia 10-05000	Nitrogen Oxides (NOx)	A	selective Catalytic Reduction	0	lb	0	0	0	0	0							
LA-0031	CAUSATEU PASS LINE PROJECT	8	100-LA-805	Reoxidation Simple Cycle Combustion Turbine	16.13	Natural Gas	283	MMBtu/hr		Nitrogen Oxides (NOx)	B	and good combustion practices	0	lb	0	0	0	0	0							
MI-0410	THEYFORD GENERATING STATION	5	100-12	PG PEAKERS, 3 natural gas fired simple cycle combustion turbines	16.13	natural gas	173	MMBtu/hr	Two natural gas fired simple cycle combustion turbines each with an electrical generator (nominal 130MW each, 173 MMBtu/hr heat input rating each). Each turbine is limited to 343 MMBtu of natural gas per 12 month rolling time period as determined at the end of each calendar month. Both turbines combined are limited to 3.15 MMBtu of natural gas each calendar day.	Nitrogen Oxides (NOx)	A	Dry low NOx combustors	0	lb	0	0	0	0	0							
MI-0420	OTE GAS COMPANY - MILFORD COMPRESSOR STATION	5	100-10	PG TURBINES	16.13	Natural Gas	10004	HP	Five (5) simple cycle natural gas-fired combustion turbines (CTs) to drive compressors that will be used to transport natural gas through pipelines (startup or shutdown) per clock hour. The total number of startup events for all units combined shall not exceed 500 events per 12-month rolling time period. The total number of shutdown events for all units combined shall not exceed 500 events per 12-month rolling time period. The maximum nominal rating of each turbine shall not exceed 10,504 HP (500).	Nitrogen Oxides (NOx)	A	Dry ultra low NOx burners	0	lb	0	0	0	0	0							
MI-0426	OTE GAS COMPANY - MILFORD COMPRESSOR STATION	5	100-10A	FGTURBINES (5 Simple Cycle CTs: EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5)	16.13	Natural Gas	10004	HP	Five (5) simple cycle natural gas-fired combustion turbines (CTs) to drive compressors that will be used to transport natural gas through pipelines (startup or shutdown) per clock hour. The total number of startup events for all units combined shall not exceed 500 events per 12-month rolling time period. The total number of shutdown events for all units combined shall not exceed 500 events per 12-month rolling time period. The maximum nominal rating of each turbine shall not exceed 10,504 HP (500).	Nitrogen Oxides (NOx)	A	Dry ultra low NOx burners	0	lb	0	0	0	0	0							
NY-0050	MGM MIRAGE	9	8401	TURBINE GENERATORS - UNITS C001 AND C008 AT CITY CENTER	16.13	NATURAL GAS	4.6	MMBtu/hr	THE TWO UNITS ARE IDENTICAL, SOLAR MERCURY COMBUSTION GAS TURBINES FOR ELECTRIC POWER GENERATION. EACH UNIT IS RATED AT 4.6	Nitrogen Oxides (NOx)	A	LEAN PRE-BURN TECHNOLOGY AND LIMITING THE FUEL TO NATURAL GAS	0.218	lb/MMBtu	0	0	0	0	0							
NY-0108	ROTHKILL FERRY WOODCROFT PLANT	9	2012-10-02-C-050	Small Combustion Turbine (BC 2000)	16.13	Natural Gas	10079	Permanence	Small turbine for combustion	Nitrogen Oxides (NOx)	A	ONLY	0	lb	0	0	0	0	0							
NY-0151	ROSE VALLEY PLANT	9	2012-10-02-C-050	TURBINES 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53, 54, 55, 56, 57, 58, 59, 60, 61, 62, 63, 64, 65, 66, 67, 68, 69, 70, 71, 72, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 84, 85, 86, 87, 88, 89, 90, 91, 92, 93, 94, 95, 96, 97, 98, 99, 100	16.13	NATURAL GAS	8443	HP	THESE ARE 100 HP 1000 RPM TURBINES	Nitrogen Oxides (NOx)	A	Dry Low NOx Combustion	0	lb	0	0	0	0	0	0						
NY-0161	ROSE VALLEY PLANT	9	2012-10-02-C-050	COMBUSTION TURBINE WITHIN 2400 BURNERS UNIT	16.13	Natural Gas	2400	Permanence	2400 HP 1000 RPM	Nitrogen Oxides (NOx)	A	ONLY	0	lb	0	0	0	0	0							
NY-0642	ORTON COMPRESSOR STATION	9	200701104	Compressor Turbine	16.13	Natural Gas	20000	HP	Two (2) 20,000 horsepower Solar 1500 turbines in natural gas pipeline compressor service	Nitrogen Oxides (NOx)	A	Lean's SOLAR dry emission control technology	0	lb	0	0	0	0	0							
NY-0088	ROCKWELL-GENCO/ENR STATION	9	100011001-011100	PLANT GAS TURBINES	16.13	NATURAL GAS	100	HP	PLANT GAS TURBINES are identical: 100 HP (1), 100 HP (2), 100 HP (3), 100 HP (4), 100 HP (5), 100 HP (6), 100 HP (7), 100 HP (8), 100 HP (9), 100 HP (10), 100 HP (11), 100 HP (12), 100 HP (13), 100 HP (14), 100 HP (15), 100 HP (16), 100 HP (17), 100 HP (18), 100 HP (19), 100 HP (20), 100 HP (21), 100 HP (22), 100 HP (23), 100 HP (24), 100 HP (25), 100 HP (26), 100 HP (27), 100 HP (28), 100 HP (29), 100 HP (30), 100 HP (31), 100 HP (32), 100 HP (33), 100 HP (34), 100 HP (35), 100 HP (36), 100 HP (37), 100 HP (38), 100 HP (39), 100 HP (40), 100 HP (41), 100 HP (42), 100 HP (43), 100 HP (44), 100 HP (45), 100 HP (46), 100 HP (47), 100 HP (48), 100 HP (49), 100 HP (50), 100 HP (51), 100 HP (52), 100 HP (53), 100 HP (54), 100 HP (55), 100 HP (56), 100 HP (57), 100 HP (58), 100 HP (59), 100 HP (60), 100 HP (61), 100 HP (62), 100 HP (63), 100 HP (64), 100 HP (65), 100 HP (66), 100 HP (67), 100 HP (68), 100 HP (69), 100 HP (70), 100 HP (71), 100 HP (72), 100 HP (73), 100 HP (74), 100 HP (75), 100 HP (76), 100 HP (77), 100 HP (78), 100 HP (79), 100 HP (80), 100 HP (81), 100 HP (82), 100 HP (83), 100 HP (84), 100 HP (85), 100 HP (86), 100 HP (87), 100 HP (88), 100 HP (89), 100 HP (90), 100 HP (91), 100 HP (92), 100 HP (93), 100 HP (94), 100 HP (95), 100 HP (96), 100 HP (97), 100 HP (98), 100 HP (99), 100 HP (100)	Nitrogen Oxides (NOx)	A	ONLY	0	lb	0	0	0	0	0	0	0	0	0	0	0	0
MI-0283	AFC, INC. 84" LCM PLANT	5	17-JUN-207	840 84" Natural Gas Fired Emergency Generator	16.13	Natural Gas	8.53	mmBtu/hr	750 kW or 1,134 brake horsepower	Nitrogen Oxides (NOx)	A	Good Combustion Practices and the use of Turbocharger and Aftercooler	0	lb	0	0	0	0	0	0						
NY-0067	ECHO SPRINGS GAS PLANT	9	100-1007	TURBINES 1-5	16.13	NATURAL GAS	12000	HP	12000 HP 1000 RPM SOLAR 1500 TURBINES	Nitrogen Oxides (NOx)	A	ONLY	0	lb	0	0	0	0	0	0						
NY-0007	ECHO SPRINGS GAS PLANT	9	100-1007	TURBINE 1-5	16.13	NATURAL GAS	12000	HP	12000 HP 1000 RPM SOLAR 1500 TURBINES	Nitrogen Oxides (NOx)	A	ONLY	0	lb	0	0	0	0	0	0						

RBLC Analysis for Natural Gas-Fired Lean-Burn RICE – NO_x Control

IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology	Good Combustion Practices and Fuel Selection	Clean Burn Technology ^a	Selective Catalytic Reduction (SCR) ^{b,c}	Non-Selective Catalytic Reduction (NSCR) ^c
	Control Technology Description	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 EPA's "Good Combustion Practices" guidance document, good combustion practices can be 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 optimal NO _x emissions.	Natural gas fueled engines that operate with a fuel-lean air/fuel ratio are capable of low NO _x emissions.	A nitrogen-based reagent (e.g., ammonia, urea) is injected into the exhaust stream downstream of the combustion unit. The reagent reacts selectively with NO _x to produce molecular N ₂ and water in a reactor vessel containing a metallic or ceramic catalyst.	This technique uses residual hydrocarbons and CO in rich-burn engine exhaust as a reducing agent for NO _x . In an NSCR, hydrocarbons and CO are oxidized by O ₂ and NO _x . The excess hydrocarbons, CO, and NO _x pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H ₂ O and CO ₂ , while reducing NO _x to N ₂ . ^b
	Other Considerations	N/A	N/A	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 reagent may 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.	N/A
ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Included in RBLC for the control of NO _x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Included in RBLC for the control of NO _x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Not included in RBLC for the control of NO _x emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Not included in RBLC for the control of NO _x emissions from large natural gas-fired lean-burn stationary internal combustion engines.
	Feasibility Discussion	Technically feasible.	Technically feasible.	Technically infeasible. Site and unit-specific complications exclude SCR as a control option for the 2SLB engines at this facility.	Technically infeasible. The NSCR technique is limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes 4-stroke rich-burn naturally aspirated engines and some 4-stroke rich-burn turbocharged engines. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures.
RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	Base Case	80 - 93%		

a. U.S. EPA, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document – NO_x Emissions from Stationary Reciprocating Internal Combustion Engines", EPA-453/R-93-032, Section 5.2.5.4, July 1993

b. 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.

c. U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines"

Engine RBLC Results
Completed RBLC Search on 9/19/2019 for a ten year period of 1/1/2019 to 09/19/2019

RBLCD	FACILITY NAME	EPA REGION	PERMIT NUM	PROCESS NAME	PROCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	COST EFFECTIVENESS	INCREMENTAL COST EFFECTIVENESS	Cost Verified	DOLLAR YEAR USED IN COST ESTIMATES
CA-1152	AVONEL ENERGY PROJECT	9	9-018-01	EMERGENCY ICE ENGINE	17.13	NATURAL GAS	5500 HP	UNIT IS 860 HP		Nitrogen Oxides (NOx)	A	SCR, OPERATIONAL LIMIT OF 50 HR/YR	0	0	0	0	0	0	0
CA-1222	RYOCERA AMERICA INC	9	9-011-APP-00034	ICE Spark Ignition Internal Combustion Engine	17.13	Natural Gas	2889 bhp	2889 bhp	either one is 2328 bhp	Nitrogen Oxides (NOx)	A	SCR with process control NOx monitor	0	0	0	0	0	0	0
CA-1240	GOLD COAST PACKING	9	14646	Internal Combustion Engine	17.13	Natural Gas	881 bhp	881 bhp		Nitrogen Oxides (NOx)	A	SCR Catalyst-Urea Injection	0	0	0	0	0	0	0
*L-0368	NUCOR STEEL FLORIDA FACILITY	4	1500472-001-AC	Emergency Engines	17.13	Natural Gas	0	0	Two 2,000 kW Emergency Natural Gas-Fired Generators & One Emergency Natural Gas-Fired 500 HP Fire Pump	Nitrogen Oxides (NOx)	P	Good combustion practices	0	0	0	0	0	0	0
IN-0167	MACINATION LLC	5	181-12081-00054	EMERGENCY GENERATOR	17.13	NATURAL GAS	620 HP	620 HP	EMERGENCY NATURAL GAS GENERATOR, IDENTIFIED AS EU037, EXHAUSTS TO STACK 55015	Nitrogen Oxides (NOx)	P	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0	0	0	0	0	0	0
*S-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	7	C-13309	Spark Ignition RICE emergency AC generators	17.13	Natural Gas	450 kW	450 kW	Two (2) spark ignition emergency AC generators, each rated at 450 kW (approximately 604 bhp), which shall burn only natural gas for fuel for the purpose of providing emergency power.	Nitrogen Oxides (NOx)	N		0	0	0	0	0	0	0
*S-0030	STATION	7	C-13309	IG/Gas	17.13	Natural Gas	105 MW	105 MW	520CWS4), used to generate electricity. The generating capacity of	Nitrogen Oxides (NOx)	N		0	0	0	0	0	0	0
VS-0035	LACEY RANDALL GENERATION FACILITY, LLC	7	C-10592	spark ignition four stroke lean burn reciprocating internal combustion engine (RICE) electric generating units (EGUs)	17.13	Natural Gas	12526 bHP	12526 bHP	Ten new spark ignition RICE EGUs (Wartsila model 20V345G), used to generate electricity. The generating capacity of each EGU will be 9.34 megawatts (approximately 12,526 bhp). Each EGU shall be equipped with a selective catalytic reduction (SCR) system and an oxidation catalyst, and shall burn only pipeline quality natural gas for fuel.	Nitrogen Oxides (NOx)	A	Selective Catalytic Reduction (SCR) system and oxidation catalyst	0	0	0	0	0	0	0
LA-0257	SABINE PASS LNG TERMINAL	8	PSD-LA-705(M)3	Generator Engines (2)	17.13	Natural Gas	2012 hp	2012 hp		Nitrogen Oxides (NOx)	P	Comply with 40 CFR 60 Subpart JJJ	0	0	0	0	0	0	0
LA-0287	ALEXANDRIA COMPRESSOR STATION	8	PSD-LA-787	Emergency Generator Reciprocating Engine (G30, RGT 15)	17.13	Natural Gas	1175 HP	1175 HP	Non-emergency operation limited to 100 hours per year. Engine is subject to NPS Subpart JJJ.	Nitrogen Oxides (NOx)	P	Good combustion practices; use of natural gas as fuel; limit non-emergency use to <= 100 hours per year; adherence to the permittee's operating and maintenance practices	2.6 G/BHP-yr	0	0	0	0	0	0
LA-0292	HOLBROOK COMPRESSOR STATION	8	PSD-LA-789(M) 3	Waukesha 16V 275GL Compressor Engines Nos. 1-12	17.13	Natural Gas	5000 HP	5000 HP		Nitrogen Oxides (NOx)	P	Lean-burn combustion, use of natural gas as fuel, good equipment design, and proper combustion techniques	0.41 G/BHP-yr	0	0	0	0	0	0
MI-0393	RAY COMPRESSOR STATION	5	5206-09	Five spark ignition internal combustion engines	17.13	Natural Gas	12 MW/BTU/hr	12 MW/BTU/hr	Five (5) natural gas fired spark ignition ICs, Caterpillar G3616, 4735 hp lean burn engines with 2 way oxidation catalysts.	Nitrogen Oxides (NOx)	N	Low emission design and good combustion practices	0	0	0	0	0	0	0
MI-0393	RAY COMPRESSOR STATION	5	5206-09	Emergency generator	17.13	Natural Gas	5000 w/yr	5000 w/yr	This is an emergency generator which is limited to 500 hours per year of operation.	Nitrogen Oxides (NOx)	N		0	0	0	0	0	0	0
MI-0401	MIDLAND POWER STATION	5	524-118	Emergency generator	17.13	Natural Gas	1200 kW output	1200 kW output	This is a 1200kW (output) natural gas fired emergency generator. The engine was manufactured after 2009.	Nitrogen Oxides (NOx)	N		0	0	0	0	0	0	0
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	5	107-132	Emergency Engine-natural gas (EUNGENINE)	17.13	Natural Gas	1000 kW	1000 kW	A 1,000 kilowatts (kW) natural gas-fueled emergency engine manufactured in 2013. The engine is used to charge the batteries in the uninterruptible power supply (UPS) battery system (EUNGENINE). Restricted to 500 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	P	Good combustion practices	0	0	0	0	0	0	0
MI-0420	JTE GAS COMPANY - MILFORD COMPRESSOR STATION	5	185-15	EUN EM GEN	17.13	Natural Gas	225 w/yr	225 w/yr	A 508 kilowatts (kW) natural gas-fueled emergency engine manufactured in 2011 or later. The engine is used to provide electrical power to the station and support equipment in the event power from the public utility grid system is lost (EUN_EM_GEN). Restricted to 225 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	B	Low NOx design (turbo charger and after cooler) and good combustion practices.	0	0	0	0	0	0	0
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	5	107-13C	EUNGENINE (Emergency engine-natural gas)	17.13	Natural Gas	500 w/yr	500 w/yr	A 1,462 HP natural gas-fueled emergency engine manufactured in 2016 serving a 3,040 kW generator. The engine is used to charge the batteries in the uninterruptible power supply (UPS) battery system (EUNGENINE). Restricted to 144 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	P	Good combustion practices.	0	0	0	0	0	0	0
MI-0426	JTE GAS COMPANY - MILFORD COMPRESSOR STATION	5	185-15A	EUN EM GEN (Natural gas emergency engine)	17.13	Natural Gas	205 w/yr	205 w/yr	A nominally rated 1,300 electrical kilowatts (kW) output emergency genset containing a 1,618 HP natural gas fueled engine manufactured in 2011 or later. The engine is used to provide electrical power to the station and support equipment in the event power from the public utility grid system is lost (EUN_EM_GEN). Restricted to 205 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	B	Low NOx design (turbo charger and after cooler) and good combustion practices.	0	0	0	0	0	0	0
OK-0148	BUFFALO CREEK PROCESSING PLANT	6	2012-1026-C-PSD	Large Internal Combustion Engines (8xgt500 hp)	17.13	Natural Gas	1775 horsepower	1775 horsepower	Caterpillar G3608LE 45L times 6.	Nitrogen Oxides (NOx)	P	Ultra Lean Burn	0	0	0	0	0	0	0
OK-0148	BUFFALO CREEK PROCESSING PLANT	6	2012-1026-C-PSD	Large Internal Combustion Engines (8xgt500 hp)	17.13	Natural Gas	2370 horsepower	2370 horsepower	Caterpillar G3608LE 45L times 4.	Nitrogen Oxides (NOx)	P	Ultra Lean Burn	0	0	0	0	0	0	0
OK-0152	ROSE VALLEY PLANT	6	2012-1895-C-PSD	COMPRESSOR ENGINE 1, 775-HP CAT G3608LE	17.13	NATURAL GAS	1775 HP	1775 HP	THERE ARE TO BE TEN (10) ONE-KIND ENGINES. THERE ARE TO BE TWO (2) ENGINES, EACH EQUIPPED W/AN OXIDATION CATALYST. THESE WILL BE LIMITED USE (< 750 HOURS PER YEAR).	Nitrogen Oxides (NOx)	N		0	0	0	0	0	0	0
OK-0153	ROSE VALLEY PLANT	6	2012-1393-C-PSD	EMERGENCY GENERATORS 3,889-HP CAT G3520C-184	17.13	NATURAL GAS	2889 HP	2889 HP		Nitrogen Oxides (NOx)	P	LEAN BURN COMBUSTION.	0	0	0	0	0	0	0
PA-0287	WELLING COMPRESSOR STATION	3	3-63-00958	CATERPILLAR G3516B COMPRESSOR ENGINES (2)	17.13	Natural Gas	0	0		Nitrogen Oxides (NOx)	N		6.46 T/yr	EACH ENGINE	0	0	0	0	0
PA-0287	WELLING COMPRESSOR STATION	3	3-63-00958	WAUKESHA P1900G COMPRESSOR ENGINES (4)	17.13	Natural Gas	0	0		Nitrogen Oxides (NOx)	A	3-way catalyst, Johnson Matthey	3.82 T/yr	EACH ENGINE	0	0	0	0	0
PA-0297	KELLY IMG ENERGY LLC/KELLY IMG PLT	3	3-16-381A	3.11 MW GENERATORS (WAUKESHA) #1 and #2	17.13	Natural Gas	0	0		Nitrogen Oxides (NOx)	N		0	0	0	0	0	0	0
PA-0301	CARPENTER COMPRESSOR STATION	3	3-PS-63-00987	Three Four Stroke Lean Burn Engine - Caterpillar G3608 LE 2370 BHP	17.13	Natural Gas	0	0	Controlled by oxidation Catalyst, regulated by automatic air/fuel ratio controllers.	Nitrogen Oxides (NOx)	N		0	0	0	0	0	0	0
PA-0301	CARPENTER COMPRESSOR STATION	3	3-PS-63-00987	One Four Stroke lean burn engine, Caterpillar Model G3612 TA, 3550 bhp	17.13	Natural Gas	0	0	Controlled by Oxidation catalyst, regulated by an integrated automatic air/fuel ratio controller.	Nitrogen Oxides (NOx)	N		0	0	0	0	0	0	0
PA-0302	CLEMMONT COMPRESSOR STATION	3	3-PS-24-180A	Spark Ignited 4 stroke Rich Burn Engine (7 units)	17.13	Natural Gas	0	0	Spark Ignited 4 stroke Rich Burn Engine (7 units)	Nitrogen Oxides (NOx)	A	NSCR	0	0	0	0	0	0	0
TX-0642	SINTON COMPRESSOR STATION	6	PSD7X1304	Emergency Engine	17.13	Natural Gas	1332 hp	1332 hp	1328 horsepower standby generator operating no more than 100 hours per year	Nitrogen Oxides (NOx)	N		0	0	0	0	0	0	0
TX-0642	SINTON COMPRESSOR STATION	6	PSD7X1304	Emergency Engine	17.13	Natural Gas	1332 hp	1332 hp	R1 Caterpillar 3516 ultra-lean burn compressor engines at 1,188 hp each	Nitrogen Oxides (NOx)	P	Ultra-lean burn technology.	0	0	0	0	0	0	0
TX-0680	SODORA GAS PLANT	6	106139 PSD7X1236	Refrigeration compressor engine	17.13	Natural Gas	1182 hp	1182 hp	18 ultra-lean burn Caterpillar 3516 engines at 1,380 hp each	Nitrogen Oxides (NOx)	P	Ultra-lean burn technology.	0	0	0	0	0	0	0
TX-0680	SODORA GAS PLANT	6	106139 PSD7X1236	Recompression compressor engine	17.13	Natural Gas	1380 hp	1380 hp	18 ultra-lean burn Caterpillar 3516 engines at 1,380 hp each	Nitrogen Oxides (NOx)	P	Ultra-lean burn technology.	0	0	0	0	0	0	0
TX-0692	RED GATE POWER PLANT	6	106544 PSD7X1323	121 reciprocating internal combustion engines	17.13	Natural Gas	18 MW	18 MW	Each cryogenic plant at the Ramsey Gas Plant will have 5 natural gas-fired compressor engines. The residue gas from each plant will be compressed by five compressors.	Nitrogen Oxides (NOx)	A	Selective Catalytic Reduction (SCR)	0	0	0	0	0	0	0
TX-0755	RAMSEY GAS PLANT	6	PSD7X1350-D-3546	Internal Combustion Compressor Engines	17.13	Natural Gas	206149 MBtu/yr	206149 MBtu/yr		Nitrogen Oxides (NOx)	P	Ultra Lean burn engines firing natural gas	0	0	0	0	0	0	0
WY-0066	MEDICINE BOW IGL PLANT	8	CT-5873	BLACK START GENERATOR 1	17.13	NATURAL GAS	2889 HP	2889 HP	250 HOURS OF OPERATION	Nitrogen Oxides (NOx)	N	LIMITED OPERATING HOURS (250 HR/YR)	0.8 T/yr	ANNUAL	0	0	0	0	0
WY-0066	MEDICINE BOW IGL PLANT	8	CT-5873	BLACK START GENERATOR 2	17.13	NATURAL GAS	2889 HP	2889 HP	LIMITED OPERATING HOURS (250 HR/YR)	Nitrogen Oxides (NOx)	N	LIMITED OPERATING HOURS (250 HR/YR)	0.8 T/yr	ANNUAL	0	0	0	0	0
WY-0066	MEDICINE BOW IGL PLANT	8	CT-5873	BLACK START GENERATOR 3	17.13	NATURAL GAS	2889 HP	2889 HP	LIMITED OPERATING HOURS (250 HR/YR)	Nitrogen Oxides (NOx)	N	LIMITED OPERATING HOURS (250 HR/YR)	0.8 T/yr	ANNUAL	0	0	0	0	0

APPENDIX B - COST ANALYSIS CALCULATIONS

DCP Operating Company, LP
Linam Ranch Gas Plant

Turbine Cost Analysis	Interest Rate:	5.50%
All Units	Period (yrs):	20

Control Equipment	Unit	Capital Cost	Total Annual Cost*	Emission Reduction	Cost Effectiveness
		(\$)	(\$)	(tpy)	(\$/ton)
Improved Combustion (SoLoNO _x)	29	\$188,125	\$605,743	29.21	\$21,278.01
	30	\$188,125	\$618,799	25.97	\$23,829.64
	31	\$1,377,841	\$269,048	86.78	\$3,100.23
	32B	\$1,377,841	\$268,605	21.04	\$12,764.91
Selective Catalytic Reduction (SCR)	29	\$1,500,000	\$256,678	35.81	\$7,168.48
	30	\$1,500,000	\$254,319	33.08	\$7,688.74
	31	\$1,500,000	\$246,027	78.07	\$3,151.46
	32B	\$1,500,000	\$231,770	19.51	\$11,880.95

* Total Annual Cost includes the annualized capital cost as well as the direct and indirect annual operating costs.

Control Equipment	Unit	Capital Cost	Total Annual Cost*	Emission Reduction	Cost Effectiveness
		(\$)	(\$)	(tpy)	(\$/ton)
Improved Combustion (SoLoNO _x)	29	\$188,125	\$605,743	0	N/A
	30	\$188,125	\$618,799	0	N/A
	31	\$1,377,841	\$269,048	31.98	\$8,413.01
	32B	\$1,377,841	\$268,605	3.82	\$70,315.54
Selective Catalytic Reduction (SCR)	29	\$1,500,000	\$256,678	13.08	\$19,623.74
	30	\$1,500,000	\$254,319	5.99	\$42,457.25
	31	\$1,500,000	\$246,027	39.71	\$6,195.60
	32B	\$1,500,000	\$231,770	7.45	\$31,110.07

* Total Annual Cost includes the annualized capital cost as well as the direct and indirect annual operating costs.

Control Equipment	Unit	Energy Consumption
		MWh/yr
Selective Catalytic Reduction (SCR)	29	349.7
	30	333.1
	31	165.8
	32B	163.1
	Total	1011.6

DCP Operating Company, LP

Linam Ranch Gas Plant

Solar Taurus 70-10302S	Interest Rate:	5.50%
Unit 29	Period (yrs):	20

Base (35 ppm)

NO _x ppm:	35 ppm	
NO _x lb/hr:	11.82 lb/hr	<-- From 2016 EI calculations
NO _x tpy:	51.15 tpy	<-- From 2016 EI calculations

SoLoNO_x (15 ppm)

NO _x guarantee:	15 ppm	<-- from Solar
NO _x lb/hr:	5.07 lb/hr	
NO _x tpy:	21.94 tpy	
Total Cap Investment	\$ 188,125	<-- from Solar
Annualized TCI:	\$ 15,742	<-- Based on interest rate, year and TCI
Annual O&M Costs ¹ :	\$ 605,743	<-- Includes O&M and overhaul costs
Total Annual Costs:	\$ 621,486	
Emissions Reduction:	29.21 tpy	

Cost Effectiveness:	\$ 21,278.01 \$/ton
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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 3.3.3, Corrected from 1999 to 2018 dollars based on CEPCI. Also includes cost of overhaul as provided by SoLoNO_x.

SCR (10 ppm)

NO _x guarantee:	10 ppm	<-- Assumed 70% from AP-42 Section 3.1.4.3
NO _x lb/hr:	3.55 lb/hr	
NO _x tpy:	15.35 tpy	
Total Cap Investment	\$ 1,500,000	<-- Vendor estimate
Annualized TCI:	\$ 125,519	<-- Based on interest rate, year and TCI
Annual O&M Costs:	\$ 131,159	<-- from Cost Control Spreadsheet
Total Annual Costs:	\$ 256,678	
Emissions Reduction:	35.81 tpy	

Cost Effectiveness:	\$ 7,168.48 \$/ton
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Incremental Cost:	\$ (14,109.53) \$/ton
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Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine?

Industrial

Is the SCR for a new turbine or retrofit of an existing turbine?

Retrofit

What type of fuel does the unit burn?

Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?

77.63 MMBtu/hour

What is the higher heating value (HHV) of the fuel?

1,020 Btu/scf

What is the estimated actual annual fuel consumption?

658,580,746 scf/Year

Enter the net plant heat input rate (NPHR)

8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation

3710 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired turbines, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method:

Method 1

Method 2

Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})

365 days

Number of days the turbine operates (t_{plant})

365 days

Inlet NO_x Emissions (NO_x_{in}) to SCR

0.152 lb/MMBtu

Outlet NO_x Emissions (NO_x_{out}) from SCR

0.046 lb/MMBtu

Stoichiometric Ratio Factor (SRF)

1.050

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst (H_{catalyst})

24,000 hours

Estimated SCR equipment life

20 Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})

29 percent*

Density of reagent as stored (ρ_{stored})

56 lb/cubic feet*

Number of days reagent is stored (t_{storage})

14 days

Number of SCR reactor chambers (n_{scr})

1

Number of catalyst layers (R_{layer})

3

Number of empty catalyst layers (R_{empty})

1

Ammonia Slip (Slip) provided by vendor

2 ppm

Volume of the catalyst layers (Vol_{catalyst})

UNK Cubic feet

Flue gas flow rate (Q_{fluegas})

UNK acfm

Gas temperature at the SCR inlet (T)

650 °F

Base case fuel gas volumetric flow rate factor (Q_{fuel})

484 ft³/min-MMBtu/hour

Select the reagent used

Ammonia

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution71 lbs/ft³

29.4% aqueous NH₃56 lbs/ft³

Enter the cost data for the proposed SCR:

Desired dollar-year	2018	
CEPCI for 2018	603.1 Enter the CEPCI value for 2018	603.1 2018 CEPCI
Annual Interest Rate (i)	5.5 Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/ .)
Reagent (Cost _{reag})	0.293 \$/gallon for 29% ammonia*	* \$0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity (Cost _{elect})	0.0676 \$/kWh	* \$0.0676/kWh is a default value for electricity cost. User should enter actual value, if known.
Catalyst cost (CC _{replace})	227.00 \$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 \$/hour (including benefits)*	* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.
Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.		

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf)	
Electricity Cost (\$/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a .	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA’s Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6 .	
Operator Labor Rate (\$/hour)	\$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA’s Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6 .	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q _B) =	HHV x Max. Fuel Rate =	78	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	666,724,528	scf/Year
Actual Annual fuel consumption (Mactual) =		658,580,746	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CF _{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.988	fraction
Total operating time for the SCR (t _{op}) =	CF _{total} x 8760 =	8653	hours
NOx Removal Efficiency (EF) =	(NO _x _{in} - NO _x _{out})/NO _x _{in} =	70.0	percent
NOx removed per hour =	NO _x _{in} x EF x Q _B =	8.28	lb/hour
Total NO _x removed per year =	(NO _x _{in} x EF x Q _B x t _{op})/2000 =	35.81	tons/year
NO _x removal factor (NRF) =	EF/80 =	0.88	
Volumetric flue gas flow rate (q _{flue gas}) =	Q _{fuel} x QB x (460 + T)/(460 + 700)n _{scr} =	35,954	acfm
Space velocity (V _{space}) =	q _{flue gas} /Vol _{catalyst} =	137.74	/hour
Residence Time	1/V _{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO ₂ Emission rate =	(%S/100)x(64/32)*1x10 ⁶)/HHV =		
Elevation Factor (ELEVF) =	14.7 psia/P =	1.14	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6] ^{5.256} x (1/144)* =	12.8	psia
Retrofit Factor (RF)	Retrofit to existing turbine	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

Not applicable; factor applies only to coal-fired turbines

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate) ^Y -1) , where Y = H _{catalysts} /(t _{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume (Vol _{catalyst}) =	2.81 x Q _B x EF _{adj} x Slip _{adj} x NO _x _{adj} x S _{adj} x (T _{adj} /N _{scr})	261.03	Cubic feet
Cross sectional area of the catalyst (A _{catalyst}) =	q _{flue gas} /(16ft/sec x 60 sec/min)	37	ft ²
Height of each catalyst layer (H _{layer}) =	(Vol _{catalyst} /(R _{layer} x A _{catalyst})) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A _{SCR}) =	1.15 x A _{catalyst}	43	ft ²
Reactor length and width dimensions for a square reactor =	(A _{SCR}) ^{0.5}	6.6	feet
Reactor height =	(R _{layer} + R _{empty}) x (7ft + h _{layer}) + 9ft	50	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft ³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m _{reagent}) =	(NO _x _{in} x Q _B x EF x SRF x MW _R)/MW _{NOx} =	3	lb/hour
Reagent Usage Rate (m _{sol}) =	m _{reagent} /Csol =	11	lb/hour
	(m _{sol} x 7.4805)/Reagent Density	1	gal/hour
Estimated tank volume for reagent storage =	(m _{sol} x 7.4805 x t _{storage} x 24)/Reagent Density =	500	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i) ⁿ /(1+ i) ⁿ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF) ^{0.43} = where A = (0.1 x QB) for industrial turbines.	39.92 349683.0549 349.6830549	kW kWh/yr MWh/yr

Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	\$1,500,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)	
TAC = Direct Annual Costs + Indirect Annual Costs	

Direct Annual Costs (DAC) =	\$128,441 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$128,268 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$256,709 in 2018 dollars

Direct Annual Costs (DAC)	
DAC = (Annual Maintenance Cost) + (Annual Operating Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)	

Annual Maintenance Cost =	$0.005 \times \text{TCI} =$	\$7,500 in 2018 dollars
Annual Operating Cost =	$\text{Operator Labor Rate} \times \text{Hours/Day} \times t_{\text{SCR}} =$	\$87,600 in 2018 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$3,756 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$23,350 in 2018 dollars
Annual Catalyst Replacement Cost =		\$6,235 in 2018 dollars
	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}}) \times \text{FWF}$	
Direct Annual Cost =		\$128,441 in 2018 dollars

Indirect Annual Cost (IDAC)	
IDAC = Administrative Charges + Capital Recovery Costs	

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$2,718 in 2018 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$125,550 in 2018 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$128,268 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year	
----------------------------------------------------------	--

Total Annual Cost (TAC) =	\$256,709 per year in 2018 dollars
NOx Removed =	36 tons/year
Cost Effectiveness =	\$7,169 per ton of NOx removed in 2018 dollars

DCP Operating Company, LP

Linam Ranch Gas Plant

Solar Taurus 70-9702S	Interest Rate:	5.50%
Unit 30	Period (yrs):	20

Base (33 ppm)

NO _x ppm:	33 ppm	
NO _x lb/hr:	11.26 lb/hr	<-- From 2016 EI calculations
NO _x tpy:	47.25 tpy	<-- From 2016 EI calculations

SoLoNO_x (15 ppm)

NO _x guarantee:	15 ppm	<-- from Solar
NO _x lb/hr:	5.07 lb/hr	
NO _x tpy:	21.28 tpy	
Total Cap Investment	\$ 188,125	<-- from Solar
Annualized TCI:	\$ 15,742	<-- Based on interest rate, year and TCI
Annual O&M Costs ¹ :	\$ 603,057	<-- Includes O&M and overhaul costs
Total Annual Costs:	\$ 618,799	
Emissions Reduction:	25.97 tpy	

Cost Effectiveness:	\$ 23,829.64 \$/ton
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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 3.3.3, Corrected from 1999 to 2018 dollars based on CEPCI. Also includes cost of overhaul as provided by SoLoNO_x.

SCR (10 ppm)

NO _x guarantee:	10 ppm	<-- Assumed 70% from AP-42 Section 3.1.4.3
NO _x lb/hr:	3.38 lb/hr	
NO _x tpy:	14.18 tpy	
Total Cap Investment	\$ 1,500,000	<-- Vendor estimate
Annualized TCI:	\$ 125,519	<-- Based on interest rate, year and TCI
Annual O&M Costs:	\$ 128,800	<-- from Cost Control Spreadsheet
Total Annual Costs:	\$ 254,319	
Emissions Reduction:	33.08 tpy	

Cost Effectiveness:	\$ 7,688.74 \$/ton
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Incremental Cost:	\$ (16,140.90) \$/ton
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Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine?

Industrial

What type of fuel does the unit burn?

Natural Gas

Is the SCR for a new turbine or retrofit of an existing turbine?

Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?

73.95 MMBtu/hour

What is the higher heating value (HHV) of the fuel?

1,020 Btu/scf

What is the estimated actual annual fuel consumption?

608,459,422 scf/Year

Enter the net plant heat input rate (NPHR)

8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation

3710 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Not Applicable

Enter the sulfur content (%S) =

percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,828
Lignite	0	0.82	6,686

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired turbines, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method:

☐ Method 1

☐ Method 2

☒ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})

365 days

Number of days the turbine operates (t_{plant})

365 days

Inlet NO_x Emissions (NO_x_{in}) to SCR

0.15 lb/MMBtu

Outlet NO_x Emissions (NO_x_{out}) from SCR

0.046 lb/MMBtu

Stoichiometric Ratio Factor (SRF)

1.050

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst (H_{catalyst})

24,000 hours

Estimated SCR equipment life

20 Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})

29 percent*

Density of reagent as stored (ρ_{stored})

56 lb/cubic feet*

Number of days reagent is stored (t_{storage})

14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Number of SCR reactor chambers (n_{scr})

1

Number of catalyst layers (R_{layer})

3

Number of empty catalyst layers (R_{empty})

1

Ammonia Slip (Slip) provided by vendor

2 ppm

Volume of the catalyst layers (Vol_{catalyst})
(Enter "UNK" if value is not known)

UNK Cubic feet

Flue gas flow rate (Q_{fluegas})
(Enter "UNK" if value is not known)

UNK acfm

Gas temperature at the SCR inlet (T)

650 °F

Base case fuel gas volumetric flow rate factor (Q_{fuel})

484 ft³/min-MMBtu/hour

Select the reagent used

Ammonia

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SCR:

Desired dollar-year	2018	
CEPCI for 2018	603.1 Enter the CEPCI value for 2018	603.1 2018 CEPCI
Annual Interest Rate (i)	5.5 Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent (Cost _{reag})	0.293 \$/gallon for 29% ammonia*	* \$0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity (Cost _{elect})	0.0676 \$/kWh	* \$0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost (CC _{replace})	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst) 227.00	* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 \$/hour (including benefits)*	* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.
Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.		

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost (\$/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA’s Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate (\$/hour)	\$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q _B) =	HHV x Max. Fuel Rate =	74	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	635,065,475	scf/Year
Actual Annual fuel consumption (Mactual) =		608,459,422	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CF _{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.958	fraction
Total operating time for the SCR (t _{op}) =	CF _{total} x 8760 =	8393	hours
NOx Removal Efficiency (EF) =	(NOX _{in} - NOX _{out})/NOX _{in} =	70.0	percent
NOx removed per hour =	NOX _{in} x EF x Q _B =	7.88	lb/hour
Total NO _x removed per year =	(NOX _{in} x EF x Q _B x t _{op})/2000 =	33.08	tons/year
NO _x removal factor (NRF) =	EF/80 =	0.88	
Volumetric flue gas flow rate (q _{flue gas}) =	Q _{fuel} x QB x (460 + T)/(460 + 700)n _{scr} =	34,247	acfm
Space velocity (V _{space}) =	q _{flue gas} /Vol _{catalyst} =	137.74	/hour
Residence Time	1/V _{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO ₂ Emission rate =	(%S/100)x(64/32)*1x10 ⁶ /HHV =		
Elevation Factor (ELEVF) =	14.7 psia/P =	1.14	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6] ^{5.256} x (1/144)* =	12.8	psia
Retrofit Factor (RF)	Retrofit to existing turbine	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate) ^Y -1) , where Y = H _{catalyts} /(t _{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume (Vol _{catalyst}) =	2.81 x Q _B x EF _{adj} x Slipadj x NOX _{adj} x S _{adj} x (T _{adj} /N _{scr})	248.63	Cubic feet
Cross sectional area of the catalyst (A _{catalyst}) =	q _{flue gas} /(16ft/sec x 60 sec/min)	36	ft ²
Height of each catalyst layer (H _{layer}) =	(Vol _{catalyst} /(R _{layer} x A _{catalyst})) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A _{SCR}) =	1.15 x A _{catalyst}	41	ft ²
Reactor length and width dimensions for a square reactor =	(A _{SCR}) ^{0.5}	6.4	feet
Reactor height =	(R _{layer} + R _{empty}) x (7ft + h _{layer}) + 9ft	50	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft ³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m _{reagent}) =	(NOX _{in} x Q _B x EF x SRF x MW _R)/MW _{NOx} =	3	lb/hour
Reagent Usage Rate (m _{sol}) =	m _{reagent} /Csol =	11	lb/hour
	(m _{sol} x 7.4805)/Reagent Density	1	gal/hour
Estimated tank volume for reagent storage =	(m _{sol} x 7.4805 x t _{storage} x 24)/Reagent Density =	500	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i) ⁿ /(1+ i) ⁿ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF) ^{0.43} = where A = (0.1 x QB) for industrial turbines.	38.02	kW
		333078.5449	kWh/yr
		333.0785449	MWh/yr

Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	\$1,500,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)	
TAC = Direct Annual Costs + Indirect Annual Costs	

Direct Annual Costs (DAC) =	\$126,082 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$128,268 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$254,350 in 2018 dollars

Direct Annual Costs (DAC)	
DAC = (Annual Maintenance Cost) + (Annual Operating Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)	

Annual Maintenance Cost =	$0.005 \times \text{TCI} =$	\$7,500 in 2018 dollars
Annual Operating Cost =	$\text{Operator Labor Rate} \times \text{Hours/Day} \times t_{\text{SCR}} =$	\$87,600 in 2018 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$3,470 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$21,573 in 2018 dollars
Annual Catalyst Replacement Cost =		\$5,939 in 2018 dollars
	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}}) \times \text{FWF}$	
Direct Annual Cost =		\$126,082 in 2018 dollars

Indirect Annual Cost (IDAC)	
IDAC = Administrative Charges + Capital Recovery Costs	

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$2,718 in 2018 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$125,550 in 2018 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$128,268 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year	
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Total Annual Cost (TAC) =	\$254,350 per year in 2018 dollars
NOx Removed =	33 tons/year
Cost Effectiveness =	\$7,690 per ton of NOx removed in 2018 dollars

DCP Operating Company, LP

Linam Ranch Gas Plant

Solar Centaur T-4700	Interest Rate:	5.50%
Unit 31	Period (yrs):	20

Base (113 ppm)

NO _x ppm:	113 ppm	
NO _x lb/hr:	26.03 lb/hr	<-- From 2016 EI calculations
NO _x tpy:	111.53 tpy	<-- From 2016 EI calculations

SoLoNO_x (25 ppm)

NO _x guarantee:	25 ppm	<-- from Solar
NO _x lb/hr:	5.77 lb/hr	
NO _x tpy:	24.74 tpy	
Total Cap Investment	\$ 1,377,841	<-- from Solar
Annualized TCI:	\$ 115,297	<-- Based on interest rate, year and TCI
Annual O&M Costs ¹ :	\$ 153,751	<-- Includes O&M and overhaul costs
Total Annual Costs:	\$ 269,048	
Emissions Reduction:	86.78 tpy	

Cost Effectiveness:	\$ 3,100.23 \$/ton
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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 3.3.3, Corrected from 1999 to 2018 dollars based on CEPCI. Also includes cost of overhaul as provided by SoLoNO_x.

SCR (34 ppm)

NO _x guarantee:	34 ppm	<-- Assumed 70% from AP-42 Section 3.1.4.3
NO _x lb/hr:	7.81 lb/hr	
NO _x tpy:	33.46 tpy	
Total Cap Investment	\$ 1,500,000	<-- Vendor estimate
Annualized TCI:	\$ 125,519	<-- Based on interest rate, year and TCI
Annual O&M Costs:	\$ 120,508	<-- from Cost Control Spreadsheet
Total Annual Costs:	\$ 246,027	
Emissions Reduction:	78.07 tpy	

Cost Effectiveness:	\$ 3,151.46 \$/ton
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Incremental Cost:	\$ 51.22 \$/ton
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Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine?

Industrial

What type of fuel does the unit burn?

Natural Gas

Is the SCR for a new turbine or retrofit of an existing turbine?

Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?

36.80 MMBtu/hour

What is the higher heating value (HHV) of the fuel?

1,020 Btu/scf

What is the estimated actual annual fuel consumption?

309,156,078 scf/Year

Enter the net plant heat input rate (NPHR)

8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation

3710 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,828
Lignite	0	0.82	6,686

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired turbines, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method:

☐ Method 1

☐ Method 2

☒ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})

365 days

Number of days the turbine operates (t_{plant})

365 days

Inlet NO_x Emissions (NO_x_{in}) to SCR

0.71 lb/MMBtu

Outlet NO_x Emissions (NO_x_{out}) from SCR

0.21 lb/MMBtu

Stoichiometric Ratio Factor (SRF)

1.050

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst (H_{catalyst})

24,000 hours

Estimated SCR equipment life

20 Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})

29 percent*

Density of reagent as stored (ρ_{stored})

56 lb/cubic feet*

Number of days reagent is stored (t_{storage})

14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Number of SCR reactor chambers (n_{SCR})

1

Number of catalyst layers (R_{layer})

3

Number of empty catalyst layers (R_{empty})

1

Ammonia Slip (Slip) provided by vendor

2 ppm

Volume of the catalyst layers (Vol_{catalyst})

UNK Cubic feet

Flue gas flow rate (Q_{fluegas})

UNK acfm

Flue gas flow rate (Q_{fluegas})

UNK acfm

Gas temperature at the SCR inlet (T)

650 °F

Base case fuel gas volumetric flow rate factor (Q_{fuel})

484 ft³/min-MMBtu/hour

Select the reagent used

Ammonia

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SCR:

Desired dollar-year	2018	
CEPCI for 2018	603.1 Enter the CEPCI value for 2018	603.1 2018 CEPCI
Annual Interest Rate (i)	5.5 Percent*	
Reagent (Cost _{reag})	0.293 \$/gallon for 29% ammonia*	
Electricity (Cost _{elect})	0.0676 \$/kWh	
Catalyst cost (CC _{replace})	227.00 \$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)	
Operator Labor Rate	60.00 \$/hour (including benefits)*	
Operator Hours/Day	4.00 hours/day*	

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost (\$/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA’s Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate (\$/hour)	\$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q _B) =	HHV x Max. Fuel Rate =	37	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	316,047,059	scf/Year
Actual Annual fuel consumption (Mactual) =		309,156,078	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CF _{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.978	fraction
Total operating time for the SCR (t _{op}) =	CF _{total} x 8760 =	8569	hours
NOx Removal Efficiency (EF) =	(NOX _{in} - NOX _{out})/NOX _{in} =	70.0	percent
NOx removed per hour =	NOX _{in} x EF x Q _B =	18.22	lb/hour
Total NO _x removed per year =	(NOX _{in} x EF x Q _B x t _{op})/2000 =	78.07	tons/year
NO _x removal factor (NRF) =	EF/80 =	0.88	
Volumetric flue gas flow rate (q _{flue gas}) =	Q _{fuel} x QB x (460 + T)/(460 + 700)n _{scr} =	17,043	acfm
Space velocity (V _{space}) =	q _{flue gas} /Vol _{catalyst} =	115.02	/hour
Residence Time	1/V _{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO ₂ Emission rate =	(%S/100)x(64/32)*1x10 ⁶ /HHV =		
Elevation Factor (ELEVF) =	14.7 psia/P =	1.14	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6] ^{5.256} x (1/144)* =	12.8	psia
Retrofit Factor (RF)	Retrofit to existing turbine	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

Not applicable; factor applies only to coal-fired turbines

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate) ^Y -1) , where Y = H _{catalyts} /(t _{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume (Vol _{catalyst}) =	2.81 x Q _B x EF _{adj} x Slipadj x NOX _{adj} x S _{adj} x (T _{adj} /N _{scr})	148.18	Cubic feet
Cross sectional area of the catalyst (A _{catalyst}) =	q _{flue gas} /(16ft/sec x 60 sec/min)	18	ft ²
Height of each catalyst layer (H _{layer}) =	(Vol _{catalyst} /(R _{layer} x A _{catalyst})) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A _{SCR}) =	1.15 x A _{catalyst}	20	ft ²
Reactor length and width dimensions for a square reactor =	(A _{SCR}) ^{0.5}	4.5	feet
Reactor height =	(R _{layer} + R _{empty}) x (7ft + h _{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft ³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m _{reagent}) =	(NOX _{in} x Q _B x EF x SRF x MW _R)/MW _{NOx} =	7	lb/hour
Reagent Usage Rate (m _{sol}) =	m _{reagent} /Csol =	24	lb/hour
	(m _{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m _{sol} x 7.4805 x t _{storage} x 24)/Reagent Density =	1,100	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i) ⁿ /(1+ i) ⁿ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF) ^{0.43} = where A = (0.1 x QB) for industrial turbines.	18.92	kW
		165760.065	kWh/yr
		165.760065	MWh/yr

Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	\$1,500,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)	
TAC = Direct Annual Costs + Indirect Annual Costs	

Direct Annual Costs (DAC) =	\$117,790 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$128,268 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$246,058 in 2018 dollars

Direct Annual Costs (DAC)	
DAC = (Annual Maintenance Cost) + (Annual Operating Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)	

Annual Maintenance Cost =	$0.005 \times TCI =$	\$7,500 in 2018 dollars
Annual Operating Cost =	$\text{Operator Labor Rate} \times \text{Hours/Day} \times t_{SCR} =$	\$87,600 in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times \text{Cost}_{reag} \times t_{op} =$	\$8,190 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{elect} \times t_{op} =$	\$10,961 in 2018 dollars
Annual Catalyst Replacement Cost =		\$3,540 in 2018 dollars
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	
Direct Annual Cost =		\$117,790 in 2018 dollars

Indirect Annual Cost (IDAC)	
IDAC = Administrative Charges + Capital Recovery Costs	

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$2,718 in 2018 dollars
Capital Recovery Costs (CR)=	$CRF \times TCI =$	\$125,550 in 2018 dollars
Indirect Annual Cost (IDAC) =	$AC + CR =$	\$128,268 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$246,058 per year in 2018 dollars
NOx Removed =	78 tons/year
Cost Effectiveness =	\$3,152 per ton of NOx removed in 2018 dollars

DCP Operating Company, LP

Linam Ranch Gas Plant

Solar Centaur T-4000	Interest Rate:	5.50%
Unit 32B	Period (yrs):	20

Base (102 ppm)

NO _x ppm:	102 ppm	
NO _x lb/hr:	23.72 lb/hr	<-- From 2016 EI calculations
NO _x tpy:	27.87 tpy	<-- From 2016 EI calculations

SoLoNO_x (25 ppm)

NO _x guarantee:	25 ppm	<-- from Solar
NO _x lb/hr:	5.81 lb/hr	
NO _x tpy:	6.83 tpy	
Total Cap Investment	\$ 1,377,841	<-- from Solar
Annualized TCI:	\$ 115,297	<-- Based on interest rate, year and TCI
Annual O&M Costs ¹ :	\$ 153,309	<-- Includes O&M and overhaul costs
Total Annual Costs:	\$ 268,605	
Emissions Reduction:	21.04 tpy	

Cost Effectiveness:	\$ 12,764.91 \$/ton
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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 3.3.3, Corrected from 1999 to 2018 dollars based on CEPCI. Also includes cost of overhaul as provided by SoLoNO_x.

SCR (31 ppm)

NO _x guarantee:	31 ppm	<-- Assumed 70% from AP-42 Section 3.1.4.3
NO _x lb/hr:	7.12 lb/hr	
NO _x tpy:	8.36 tpy	
Total Cap Investment	\$ 1,500,000	<-- Vendor estimate
Annualized TCI:	\$ 125,519	<-- Based on interest rate, year and TCI
Annual O&M Costs:	\$ 106,251	<-- from Cost Control Spreadsheet
Total Annual Costs:	\$ 231,770	
Emissions Reduction:	19.51 tpy	

Cost Effectiveness:	\$ 11,880.95 \$/ton
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Incremental Cost:	\$ (883.96) \$/ton
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Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine?

Industrial

What type of fuel does the unit burn?

Natural Gas

Is the SCR for a new turbine or retrofit of an existing turbine?

Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?

36.21 MMBtu/hour

What is the higher heating value (HHV) of the fuel?

1,020 Btu/scf

What is the estimated actual annual fuel consumption?

83,425,083 scf/Year

Enter the net plant heat input rate (NPHR)

8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation

3710 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired turbines, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method:

☐ Method 1

☐ Method 2

☒ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})

365 days

Number of days the turbine operates (t_{plant})

365 days

Inlet NO_x Emissions (NO_x_{in}) to SCR

0.66 lb/MMBtu

Outlet NO_x Emissions (NO_x_{out}) from SCR

0.20 lb/MMBtu

Stoichiometric Ratio Factor (SRF)

1.050

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst (H_{catalyst})

24,000 hours

Estimated SCR equipment life

20 Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})

29 percent*

Density of reagent as stored (ρ_{stored})

56 lb/cubic feet*

Number of days reagent is stored (t_{storage})

14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Number of SCR reactor chambers (n_{scr})

1

Number of catalyst layers (R_{layer})

3

Number of empty catalyst layers (R_{empty})

1

Ammonia Slip (Slip) provided by vendor

2 ppm

Volume of the catalyst layers (Vol_{catalyst})
(Enter "UNK" if value is not known)

UNK Cubic feet

Flue gas flow rate (Q_{fluegas})
(Enter "UNK" if value is not known)

UNK acfm

Gas temperature at the SCR inlet (T)

650 °F

Base case fuel gas volumetric flow rate factor (Q_{fuel})

484 ft³/min-MMBtu/hour

Select the reagent used

Ammonia

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SCR:

Desired dollar-year	2018	
CEPCI for 2018	603.1 Enter the CEPCI value for 2018	603.1 2018 CEPCI
Annual Interest Rate (i)	5.5 Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/ .)
Reagent (Cost _{reag})	0.293 \$/gallon for 29% ammonia*	* \$0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity (Cost _{elect})	0.0676 \$/kWh	* \$0.0676/kWh is a default value for electricity cost. User should enter actual value, if known.
Catalyst cost (CC _{replace})	227.00 \$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 \$/hour (including benefits)*	* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.
Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.		

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf)	
Electricity Cost (\$/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a .	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA’s Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6 .	
Operator Labor Rate (\$/hour)	\$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA’s Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6 .	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q _B) =	HHV x Max. Fuel Rate =	36	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	310,980,309	scf/Year
Actual Annual fuel consumption (Mactual) =		83,425,083	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CF _{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.268	fraction
Total operating time for the SCR (t _{op}) =	CF _{total} x 8760 =	2350	hours
NOx Removal Efficiency (EF) =	(NOX _{in} - NOX _{out})/NOX _{in} =	70.0	percent
NOx removed per hour =	NOX _{in} x EF x Q _B =	16.60	lb/hour
Total NO _x removed per year =	(NOX _{in} x EF x Q _B x t _{op})/2000 =	19.51	tons/year
NO _x removal factor (NRF) =	EF/80 =	0.88	
Volumetric flue gas flow rate (q _{flue gas}) =	Q _{fuel} x QB x (460 + T)/(460 + 700)n _{scr} =	16,770	acfm
Space velocity (V _{space}) =	q _{flue gas} /Vol _{catalyst} =	116.84	/hour
Residence Time	1/V _{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO ₂ Emission rate =	(%S/100)x(64/32)*1x10 ⁶ /HHV =		
Elevation Factor (ELEVF) =	14.7 psia/P =	1.14	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6] ^{5.256} x (1/144)* =	12.8	psia
Retrofit Factor (RF)	Retrofit to existing turbine	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

Not applicable; factor applies only to coal-fired turbines

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate) ^Y -1) , where Y = H _{catalyts} /(t _{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume (Vol _{catalyst}) =	2.81 x Q _B x EF _{adj} x Slipadj x NOX _{adj} x S _{adj} x (T _{adj} /N _{scr})	143.54	Cubic feet
Cross sectional area of the catalyst (A _{catalyst}) =	q _{flue gas} /(16ft/sec x 60 sec/min)	17	ft ²
Height of each catalyst layer (H _{layer}) =	(Vol _{catalyst} /(R _{layer} x A _{catalyst})) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A _{SCR}) =	1.15 x A _{catalyst}	20	ft ²
Reactor length and width dimensions for a square reactor =	(A _{SCR}) ^{0.5}	4.5	feet
Reactor height =	(R _{layer} + R _{empty}) x (7ft + h _{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft ³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m _{reagent}) =	(NOX _{in} x Q _B x EF x SRF x MW _R)/MW _{NOx} =	6	lb/hour
Reagent Usage Rate (m _{sol}) =	m _{reagent} /Csol =	22	lb/hour
	(m _{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m _{sol} x 7.4805 x t _{storage} x 24)/Reagent Density =	1,000	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i) ⁿ /(1+ i) ⁿ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF) ^{0.43} =	18.62	kW
	where A = (0.1 x QB) for industrial turbines.	163102.6609	kWh/yr
		163.1026609	MWh/yr

Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	\$1,500,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)	
TAC = Direct Annual Costs + Indirect Annual Costs	

Direct Annual Costs (DAC) =	\$103,533 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$128,268 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$231,801 in 2018 dollars

Direct Annual Costs (DAC)	
DAC = (Annual Maintenance Cost) + (Annual Operating Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)	

Annual Maintenance Cost =	$0.005 \times TCI =$	\$7,500 in 2018 dollars
Annual Operating Cost =	$\text{Operator Labor Rate} \times \text{Hours/Day} \times t_{SCR} =$	\$87,600 in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times \text{Cost}_{reag} \times t_{op} =$	\$2,046 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{elect} \times t_{op} =$	\$2,958 in 2018 dollars
Annual Catalyst Replacement Cost =		\$3,429 in 2018 dollars
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	
Direct Annual Cost =		\$103,533 in 2018 dollars

Indirect Annual Cost (IDAC)	
IDAC = Administrative Charges + Capital Recovery Costs	

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$2,718 in 2018 dollars
Capital Recovery Costs (CR)=	$CRF \times TCI =$	\$125,550 in 2018 dollars
Indirect Annual Cost (IDAC) =	$AC + CR =$	\$128,268 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$231,801 per year in 2018 dollars
NOx Removed =	20 tons/year
Cost Effectiveness =	\$11,883 per ton of NOx removed in 2018 dollars